Consumers Energy Company
Electric Rate Case No. U-22070
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A-160 (SAM-3)	McPhail, Scott A	Voltage Regulator Controller BCA
A-161 (SAM-4)	McPhail, Scott A	Bridge Period Voltage Regulator Controller Projects
A-162 (SAM-5)	McPhail, Scott A	Voltage Regulator Controller Inventory Record
A-163 (SAM-6)	McPhail, Scott A	Metro Modernization Reliability Benefits
A-164 (SAM-7)	McPhail, Scott A	DistAM Benefits;
A-165 (SAM-8)	McPhail, Scott A	Weather Stations Reliability Benefits
A-166 (HJM-1)	Myers, Heidi J	Distribution Investment Recovery Mechanism-Annual Revenue Requirement
A-167 (JMP-1)	Partlan, Jennifer M	Bridge Period LVD Project List
A-168 (JMP-2)	Partlan, Jennifer M	Test Year LVD Project List
A-169 (JMP-3)	Partlan, Jennifer M	Conservation Voltage Reduction Measurement and Verification Independent Assessment
A-170 (JMP-4)	Partlan, Jennifer M	LVD Repetitive Outages Investment Reliability Data
A-171 (JMP-5)	Partlan, Jennifer M	Ferrand Estates Concept Approval
A-172 (JMP-6)	Partlan, Jennifer M	Summary of Overhead to Underground Project Benefit Cost Analyses (BCA)
A-173 (HLP-51)	Patton, Hannah L	Regulatory Asset and Amortization Expense of the PowerMIDrive and PowerMIFleet for the Projected 12-Month Period Ending April 30, 2028

A-174 (HLP-52)	Patton, Hannah L	Regulatory Asset and Amortization of Karn and Campbell Plant Retention and Separation Costs for the Projected 12-Month Period Ending April 30, 2028
A-175 (HLP-53)	Patton, Hannah L	Regulatory Asset and Amortization Expense of the Net Book Value of Campbell Plant 1, 2, and 3 for the Projected 12-Month Period Ending April 30, 2028
A-176 (HLP-54)	Patton, Hannah L	Regulatory Asset and Amortization Expense of Karn and Campbell Decommissioning Costs for the Projected 12-Month Period Ending April 30, 2028
A-177 (HLP-55)	Patton, Hannah L	Regulatory Asset and Amortization Expense of the Karn, Campbell, and Classic 7 Ash Disposal Costs for the Projected 12-Month Period Ending April 30, 2028
A-178 (HLP-56)	Patton, Hannah L	Regulatory Asset and Amortization Expense of the Karn, Campbell, and Classic 7 Ash Disposal Costs for the Projected 12-Month Period Ending April 30, 2028
A-179 (HLP-57)	Patton, Hannah L	Campbell Regulatory Asset – Return On for the Projected 12-Month Period Ending April 30, 2028
A-180 (HLP-58)	Patton, Hannah L	Regulatory Asset Summary of Forestry Ramp-up
A-181 (HLP-59)	Patton, Hannah L	Demand Response Revenue Requirement
A-182 (HLP-60)	Patton, Hannah L	Distribution Deferral for the projected test year ending February 28, 2026
A-183 (HLP-61)	Patton, Hannah L	Distribution Deferral for the projected test year ending April 30, 2027
A-184 (HLP-62)	Patton, Hannah L	Regulatory Asset and Amortization of the March/April 2025 Storm Deferral
A-185 (HLP-63)	Patton, Hannah L	Regulatory Asset and Amortization Expense of Case No. U-21502 (Itron Refund)
A-12 (DAS-1), Sch B-5.10	Schmoekel, Daniel A	Summary of Actual and Projected Electric Capital Expenditures for the Years 2021 through 2028
A-186 (SES-1)	Stewart, Sara E	Line Clearing O&M Expense
A-187 (SES-2)	Stewart, Sara E	Projected LVD Tree-Caused Reliability of the Line Clearing Ramp-Up Plan
A-188 (SES-3)	Stewart, Sara E	2026 HVD Line Clearing Work Plan
A-189 (SES-4)	Stewart, Sara E	2026 LVD Line Clearing Work Plan
A-190 (SES-5) CONF	Stewart, Sara E	Post-Work Review Supporting Documentation Examples
A-191 (SES-6)	Stewart, Sara E	Summary of O&M Expenses Projected Using Inflation
A-192 (SES-7)	Stewart, Sara E	Analysis of Projected Costs, Cost Savings, and Reliability Improvements of Implementing a Four-Year Cycle for LVD Circuits
A-193 (BJV-1)	Vanblarcum, Brian J	Development of the Property Tax Rate for the Test Year
A-194 (BJV-2)	Vanblarcum, Brian J	Amortization of Excess Deferred Federal Income Taxes for the Test Year and Tax Reform Regulatory Liability & Amortization
A-195 (MEW-1)	Wittbrodt, Mark E	Generating Unit Periodic Outages
A-196 (MEW-2)	Wittbrodt, Mark E	Generating Unit Availability Projections
A-197 (MEW-4)	Wittbrodt, Mark E	Summary of the Generation O&M Expense for the Historic Year (2025) and Test Year ending April 30, 2028
A-198 (MEW-5)	Wittbrodt, Mark E	Actual Coal Ash Disposal Plan Expenditures
A-199 (MEW-6)	Wittbrodt, Mark E	Covert LCI SFC Replacement Concept Approval
A-200 (MEW-7)	Wittbrodt, Mark E	Covert Site Spare GSU Concept Approvals
A-201 (MEW-8)	Wittbrodt, Mark E	Covert Netmation Operating System Concept Approval
A-202 (MEW-9)	Wittbrodt, Mark E	Covert Units 1 through 3 DCS Evergreen Concept Approval
A-203 (MEW-10) CONF	Wittbrodt, Mark E	Covert Plant LTSA (Confidential)
A-204 (MEW-11)	Wittbrodt, Mark E	Covert Units 1 through 3 NERC Relay Replacement Concept
A-205 (MEW-12)	Wittbrodt, Mark E	Covert Units 1 through 3 Circulating Water Pump Replacement Concept Approval
A-206 (MEW-13)	Wittbrodt, Mark E	Covert MS Tee Header Replacement Unit 1 and 3 Concept Approval
A-207 (MEW-14)	Wittbrodt, Mark E	Covert Plant Replace Sulfuric Hypo and Building Concept Approval
A-208 (MEW-15)	Wittbrodt, Mark E	Karn Unit 3 & 4 Combustion Air Heater Replacement Concept Approval
A-209 (MEW-16)	Wittbrodt, Mark E	Karn Unit 3 & 4 Ductwork Expansion Joint Replacement Concept Approval
A-210 (MEW-17)	Wittbrodt, Mark E	Karn 4 Post-Transformer Fire Remediation Concept Approval
A-211 (MEW-18)	Wittbrodt, Mark E	Karn Unit 4 ID Fan Inlet Damper Replacement Concept Approval
A-212 (MEW-19)	Wittbrodt, Mark E	Zeeland Phase 2 Gas Turbine AGP Replacement and AFS Concept Approval
A-213 (MEW-20)	Wittbrodt, Mark E	Zeeland Phase 2 Turbine Replacement Concept Approval
A-214 (MEW-21)	Wittbrodt, Mark E	Zeeland Purchase of Site Spare GSU Concept Approval

A-215 (MEW-22) CONF	Wittbrodt, Mark E	Zeeland Plant GE LTSA (Confidential)
A-216 (MEW-23)	Wittbrodt, Mark E	Zeeland Ph I & II High Recovery Gas Valves Concept Approva
A-217 (MEW-24)	Wittbrodt, Mark E	Zeeland 2C Field Exchange and Generator Major Overhaul Concept Approval
A-218 (MEW-25)	Wittbrodt, Mark E	Zeeland MS & Hot Reheat Isolation Valve Replacement Concept Approval
A-219 (MEW-26) CONF	Wittbrodt, Mark E	Jackson Plant GE LTSA (Confidential)
A-220 (MEW-27) CONF	Wittbrodt, Mark E	Jackson Plant GE LTSA Amendment 1 dated February 28, 2002 (Confidential)
A-221 (MEW-28) CONF	Wittbrodt, Mark E	Jackson Plant GE LTSA Amendment 2 dated November 17, 2017 (Confidential)
A-222 (MEW-29) CONF	Wittbrodt, Mark E	Jackson Plant GE LTSA Amendment 3 dated December 17, 2018 (Confidential)
A-223 (MEW-30) CONF	Wittbrodt, Mark E	Jackson Plant GE LTSA Assignment Agreement (Confidential)
A-224 (MEW-31)	Wittbrodt, Mark E	Jackson GSU Transformer Site Spare Concept Approval
A-225 (MEW-32)	Wittbrodt, Mark E	Jackson Variable Inlet Guide Vain Concept Approval
A-226 (MEW-33)	Wittbrodt, Mark E	Jackson Unit 7 GT Rotor Replacement Concept Approval
A-227 (MEW-34)	Wittbrodt, Mark E	Jackson Main and Aux Cooling Tower Rebuild Concept Approval
A-228 (MEW-35)	Wittbrodt, Mark E	LPS DCS Control Relay Concept Approval
A-229 (MEW-36) CONF	Wittbrodt, Mark E	LPS Unit 1 Pony Motor Replacement Concept Approval
A-230 (MEW-37) CONF	Wittbrodt, Mark E	LPS Units 2 & 4 Head Cover and Bottom Ring Replacement Concept Approval (Confidential)
A-231 (MEW-38)	Wittbrodt, Mark E	LPS Administration Building Concept Approval
A-232 (MEW-39)	Wittbrodt, Mark E	LPS Replace 480V DLC Concept Approval
A-233 (MEW-40)	Wittbrodt, Mark E	LPS Governor Replacement Concept Approval
A-234 (MEW-41)	Wittbrodt, Mark E	LPS Intake Gate and Gate House Concept Approval
A-235 (MEW-42)	Wittbrodt, Mark E	LPS Life Cycle Management Concept Approval
A-236 (MEW-43)	Wittbrodt, Mark E	Emergent Reliability Funding 2025 Detail
A-237 (SES-8)	Stewart, Sara E	Analysis of Costs, Benefits, and Reliability Improvements of Removing 100% of Tree Canopy in First Zones
A-238 (BAG-3)	Gray, Brittani A	Rate Case Customer Communications

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U- 22070

EXHIBITS

OF

RACHEL R. BABALE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources
Electric Low Voltage Distribution (LVD) Workplan

Case No.: U-22070
Exhibit No.: A-30 (RRB-1)
Page: 1 of 1
Witness: RRBabale
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Description	2024 YE Actual	2025 YE Actual	2026 YE Projected 12 Mos Ending 12/31/2026	2027 YE Projected 12 Mos Ending 12/31/2027	2028 YE Projected 12 Mos Ending 12/31/2028	Bridge Period 16 Mos Ending 4/30/2027	Test Period 12 Mos Ending 4/30/2028
1	LVD Electric Operations Resource Requirement (FTEs)	1,155	1,189	1,306	1,468	1,497	1,368	1,479
2	LVD Consumers Energy Resources (FTEs)	1,017	1,051	1,188	1,338	1,365	1,238	1,347
3	LVD Consumers Energy Resources (percent change from prior year FTE)		3%	13%	13%	2%	18%	13%
4	LVD Contractor Resources (FTEs)	138	138	118	130	132	130	132
5	LVD Contractor Resources (percent change from prior year FTE)		0%	-14%	10%	-4%	10%	2%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources
Electric High Voltage Distribution (HVD) Workplan

Case No.: U-22070
Exhibit No.: A-31 (RRB-2)
Page: 1 of 1
Witness: RRBabale
Date: June 2026

Line No.	(a) Description	(b) 2024 YE Actual	(c) 2025 YE Actual	(d) 2026 YE Projected 12 Mos Ending 12/31/2026	(e) 2027 YE Projected 12 Mos Ending 12/31/2027	(f) 2028 YE Projected 12 Mos Ending 12/31/2028	(g) Bridge Period 16 Mos Ending 4/30/2027	(h) Test Period 12 Mos Ending 4/30/2028
1	HVD Electric Operations Resource Requirement (FTEs)	409	447	386	466	425	444	425
2	HVD Consumers Energy Resources (FTEs)	209	175	166	185	184	163	184
3	HVD Consumers Energy Resources (percent change from prior year FTE)	2%	-16%	-5%	11%	-1%	-7%	11%
4	HVD Contractor Resources (FTEs)	200	272	220	281	241	281	241
5	HVD Contractor Resources (percent change from prior year FTE)		36%	-19%	28%	21%	28%	-14%

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

STACY H. BAKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Information Technology Operations O&M Expenses
For the Year 2025 and Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-17 (SHB-1)
Page: 1 of 2
Witness: SHBaker
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2025	(c) Projected 12 Mos Ending 4/30/2028
1	**Information Technology**	**49,197**	**60,320**
	Labor	10,607	12,633
	Material	1,859	2,412
	Contractor	12,988	10,700
	Contracts	21,843	33,192
	Non-Labor Overheads	-	-
	Non-Labor Other	1,899	1,382
2	**Security**	**10,179**	**13,421**
	Labor	4,085	4,458
	Material	32	2
	Contractor	3,251	2,238
	Contracts	2,262	6,420
	Non-Labor Overheads	-	-
	Non-Labor Other	550	304
3	**Total IT Operations O&M Expenses**	**59,376**	**73,741**
	Labor	14,692	17,091
	Material	1,891	2,413
	Contractor	16,240	12,939
	Contracts	24,105	39,612
	Non-Labor Overheads	-	-
	Non-Labor Other	2,449	1,686

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of IT Operations O&M Expenses Projected Using Inflation
For the Year 2025 and Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-17 (SHB-1)
Page: 2 of 2
Witness: SHBaker
Date: June 2026

Line No.	Description	(a) Actual 12 Mos Ending 12/31/2025	(b) Inflation Applied to Projected Test Year (b) * Compounded Inflation Rate	(c) Scope/ Cost Increases Net of Productivity Gains	(d) Projected O&M 12 Mos Ending 4/30/2028 (b) + (c) + (d)
1	Information Technology	49,197	3,073	8,051	60,320
2	Security	10,179	636	2,606	13,421
3	**Total IT Operations O&M Expenses**	**$ 59,376**	**$ 3,709**	**$ 10,657**	**$ 73,741**

Notes

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Historical 13 Month Average of IT Cloud Computing Prepaid Balance
For the years 2024 - 13 months balance ending December 31, 2025
Electric Allocation

Case No.: U-22070
Exhibit No.: A-18 (SHB-2)
Page: 1 of 2
Witness: SHBaker
Date: June 2026

Line No.	(a) Description	(b) Bal. Ended 12/31/2024	(c) Bal. Ended 1/31/2025	(d) Bal. Ended 2/28/2025	(e) Bal. Ended 3/31/2025	(f) Bal. Ended 4/30/2025	(g) Bal. Ended 5/31/2025	(h) Bal. Ended 6/30/2025	(i) Bal. Ended 7/31/2025	(j) Bal. Ended 8/31/2025	(k) Bal. Ended 9/30/2025	(l) Bal. Ended 10/31/2025	(m) Bal. Ended 11/30/2025	(n) Bal. Ended 12/31/2025	(o) 13 mos. Average
1	**IT Cloud Computing Prepaid**	$ (4,396,019)	$ (10,610,952)	$ (9,932,679)	$(10,894,307)	$ (9,348,181)	$ (9,275,302)	$ (8,919,050)	$ (7,978,707)	$ (6,909,261)	$ (6,577,566)	$ (5,970,116)	$ (5,047,163)	$ (4,140,471)	**$ (7,692,290)**
2	**Total**	**$ (4,396,019)**	**$ (10,610,952)**	**$ (9,932,679)**	**$(10,894,307)**	**$ (9,348,181)**	**$ (9,275,302)**	**$ (8,919,050)**	**$ (7,978,707)**	**$ (6,909,261)**	**$ (6,577,566)**	**$ (5,970,116)**	**$ (5,047,163)**	**$ (4,140,471)**	**$ (7,692,290)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected 13 Month Average of IT Cloud Computing Prepaid Balance
For the years 2027 - 13 months balance ending April 30, 2028
Electric Allocation

Case No.: U-22070
Exhibit No.: A-18 (SHB-2)
Page: 2 of 2
Witness: SHBaker
Date: June 2026

Line No.	(a) Description	(b) Bal. Ending 4/30/2027	(c) Bal. Ending 5/31/2027	(d) Bal. Ending 6/30/2027	(e) Bal. Ending 7/31/2027	(f) Bal. Ending 8/31/2027	(g) Bal. Ending 9/30/2027	(h) Bal. Ending 10/31/2027	(i) Bal. Ending 11/30/2027	(j) Bal. Ending 12/31/2027	(k) Bal. Ending 1/31/2028	(l) Bal. Ending 2/29/2028	(m) Bal. Ending 3/31/2028	(n) Bal. Ending 4/30/2028	(o) 13 mos. Average
1	**IT Cloud Computing Prepaid**	$ 13,720,911	$ 12,646,849	$ 12,786,455	$ 11,557,342	$ 11,077,560	$ 9,972,599	$ 8,722,860	$ 7,273,421	$ 5,934,340	$ 6,838,157	$ 21,696,253	$ 19,701,681	$ 22,067,548	**$ 12,615,075**
2	**Total**	**$ 13,720,911**	**$ 12,646,849**	**$ 12,786,455**	**$ 11,557,342**	**$ 11,077,560**	**$ 9,972,599**	**$ 8,722,860**	**$ 7,273,421**	**$ 5,934,340**	**$ 6,838,157**	**$ 21,696,253**	**$ 19,701,681**	**$ 22,067,548**	**$ 12,615,075**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Information Technology Investments O&M Expenses
For the Year 2025 and Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-19 (SHB-3)
Page: 1 of 2
Witness: SHBaker
Date: June 2026

Line No.	(a) Description	(b) Actual 12 Mos Ended 12/31/2025	(c) 12 Mos Ending 4/30/2028
	Investments Planning		
1	**Information Technology**	**601**	**640**
	Labor	472	640
	Software	-	-
	Material	-	-
	Contractor	129	-
	Non-Labor Overheads	-	-
	Non-Labor Other	-	-
2	**Security**	**3**	**9**
	Labor	3	9
	Software	-	-
	Material	-	-
	Contractor	-	-
	Non-Labor Overheads	-	-
	Non-Labor Other	-	-
	Investments O&M		
3	**Information Technology**	**7,097**	**9,415**
	Labor	1,495	3,796
	Software	380	417
	Material	516	387
	Contractor	4,670	4,663
	Non-Labor Overheads	-	-
	Non-Labor Other	36	153
4	**Security**	**811**	**1,537**
	Labor	252	973
	Software	202	455
	Material	2	26
	Contractor	349	83
	Non-Labor Overheads	-	-
	Non-Labor Other	6	(0)
5	**Total IT Investments O&M Expenses**	**$ 8,512**	**$ 11,601**
	Labor	2,221	5,419
	Software	583	872
	Material	518	412
	Contractor	5,149	4,746
	Non-Labor Overheads	-	-
	Non-Labor Other	41	153

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Investments O&M Expenses Projected Using Inflation
For the Year 2025 and Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-19 (SHB-3)
Page: 2 of 2
Witness: SHBaker
Date: June 2026

Line No.	(a) Description	(b) Actual 12 Mos Ending 12/31/2025	(c) Inflation Applied to Projected Test Year (b) * Compounded Inflation Rate	(d) Scope/ Cost Increases Net of Productivity Gains	(e) Projected O&M 12 Mos Ending 4/30/2028 (b) + (c) + (d)
1	**Investments Planning**	**604**	**38**	**7**	**649**
	Information Technology	601	38	1	640
	Security	3	0	6	9
2	**Investments O&M**	**7,908**	**494**	**2,550**	**10,952**
	Information Technology	7,097	443	1,875	9,415
	Security	811	51	676	1,537
3	**Total IT Investments O&M Expenses**	**$ 8,512**	**$ 532**	**$ 2,558**	**$ 11,601**

Notes

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

Schedule B-5.5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected Electric and Common Capital Expenditures
Information Technology
($000)

Case No.: U-22070
Exhibit No.: A-12 (SHB-4)
Schedule: B-5.5
Page: 1 of 2
Witness: SHBaker
Date: June 2026

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Period 12 Mos Ended 12/31/2026	(d) Projected Bridge Period 4 Mos Ending 4/30/2027	(e) Projected Bridge Period 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
1	**Corporate**	**$ 2,411**	**$ 739**	**$ 228**	**$ 966**	**$ 716**
	Labor	277	516	54	570	177
	Software	1,376	-	27	27	79
	Materials	-	-	1	1	2
	Contractor	614	-	127	127	403
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	144	223	18	241	55
	Contingency	-	-	-	-	-
2	**Customer**	**$ 2,333**	**$ 3,331**	**$ 566**	**$ 3,897**	**$ 1,636**
	Labor	291	719	153	872	416
	Software	93	-	10	10	30
	Materials	-	6	2	8	6
	Contractor	1,811	2,091	342	2,433	1,016
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	138	516	59	575	167
	Contingency	-	-	-	-	-
3	**Electric**	**$ 5,401**	**$ 11,233**	**$ 5,632**	**$ 16,865**	**$ 15,047**
	Labor	1,070	3,890	1,490	5,380	3,844
	Software	764	538	1,755	2,294	3,669
	Materials	575	1,718	456	2,174	1,114
	Contractor	2,600	3,097	1,025	4,122	4,017
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	391	1,990	906	2,896	2,402
	Contingency	-	-	-	-	-
4	**Electric & Gas Shared**	**$ 2,788**	**$ 1,344**	**$ 403**	**$ 1,747**	**$ 1,210**
	Labor	491	377	72	449	217
	Software	6	-	-	-	-
	Materials	75	7	10	17	30
	Contractor	1,912	798	296	1,094	888
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	303	163	25	188	75
	Contingency	-	-	-	-	-
5	**IT/Digital Foundation**	**$ 19,469**	**$ 58,816**	**$ 20,181**	**$ 78,997**	**$ 28,862**
	Labor	2,434	11,398	4,562	15,959	5,317
	Software	961	937	199	1,136	402
	Materials	10,550	12,758	4,415	17,173	13,933
	Contractor	4,811	28,391	8,198	36,589	5,618
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	714	5,332	2,808	8,139	3,592
	Contingency	-	-	-	-	-
6	**Security**	**$ 4,635**	**$ 6,928**	**$ 4,386**	**$ 11,315**	**$ 11,229**
	Labor	525	1,013	510	1,523	1,433
	Software	2,369	264	1,517	1,780	3,126
	Materials	31	2,854	1,618	4,472	4,621
	Contractor	1,528	2,288	373	2,661	1,083
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	182	510	368	878	965
	Contingency	-	-	-	-	-
7	**Total Information Technology Capital**	**$ 37,036**	**$ 82,391**	**$ 31,396**	**$ 113,788**	**$ 58,700**
	Labor	5,087	17,912	6,841	24,754	11,405
	Software	5,569	1,739	3,508	5,247	7,307
	Materials	11,232	17,343	6,502	23,844	19,706
	Contractor	13,276	36,664	10,361	47,025	13,025
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	1,872	8,733	4,184	12,917	7,256
	Contingency	-	-	-	-	-
		32,401	75,463	27,010	102,473	47,471

MICHIGAN PUBLIC SERVICE COMMISSION **Schedule B-5.5**

Consumers Energy Company

Summary of Actual & Projected Electric and Common Capital Expenditures

Information Technology

($000)

Case No.: U-22070
Exhibit No.: A-12 (SHB-4)
Schedule: B-5.5
Page: 2 of 2
Witness: SHBaker
Date: June 2026

Line No	(a)	(b)	(c)	(d)	(e)
			Projected		
		4 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028	28 Mos Ending 4/30/2028
8	**Corporate**	**$ 246**	**$ 720**	**$ 716**	**$ 1,682**
	Labor	172	398	177	747
	Software	-	27	79	107
	Materials	-	1	2	3
	Contractor	-	127	403	530
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	74	167	55	296
	Contingency	-	-	-	-
9	**Customer**	**$ 1,146**	**$ 2,751**	**$ 1,636**	**$ 5,534**
	Labor	265	607	416	1,288
	Software	-	10	30	40
	Materials	2	6	6	14
	Contractor	703	1,730	1,016	3,449
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	176	399	167	743
	Contingency	-	-	-	-
10	**Electric**	**$ 3,889**	**$ 12,976**	**$ 15,047**	**$ 31,912**
	Labor	1,225	4,156	3,844	9,224
	Software	181	2,112	3,669	5,963
	Materials	498	1,676	1,114	3,287
	Contractor	1,320	2,802	4,017	8,140
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	666	2,230	2,402	5,298
	Contingency	-	-	-	-
11	**Electric & Gas Shared**	**$ 530**	**$ 1,217**	**$ 1,210**	**$ 2,957**
	Labor	115	335	217	667
	Software	-	-	-	-
	Materials	2	14	30	46
	Contractor	361	733	888	1,982
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	52	135	75	263
	Contingency	-	-	-	-
12	**IT/Digital Foundation**	**$ 10,502**	**$ 68,495**	**$ 28,862**	**$ 107,859**
	Labor	1,723	14,237	5,317	21,277
	Software	272	864	402	1,538
	Materials	4,253	12,921	13,933	31,107
	Contractor	3,629	32,960	5,618	42,206
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	626	7,513	3,592	11,731
	Contingency	-	-	-	-
13	**Security**	**$ 2,309**	**$ 9,005**	**$ 11,229**	**$ 22,544**
	Labor	338	1,185	1,433	2,956
	Software	88	1,692	3,126	4,906
	Materials	951	3,521	4,621	9,094
	Contractor	763	1,899	1,083	3,744
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	170	708	965	1,843
	Contingency	-	-	-	-
14	**Total Information Technology Capital**	**$ 18,623**	**$ 95,165**	**$ 58,700**	**$ 172,488**
	Labor	3,836	20,917	11,405	36,159
	Software	541	4,706	7,307	12,555
	Materials	5,706	18,139	19,706	43,551
	Contractor	6,775	40,251	13,025	60,051
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	1,765	11,152	7,256	20,173
	Contingency	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(l)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
1	2025	2025 Union Contract Changes	Software(Intangible)	Corporate	The Human Resources - 2025 Union Changes project will implement SAP and other system changes required as a result of three collective bargaining agreements which will be renegotiated and ratified. Collective bargaining agreements expire every five years for Operating Maintenance and Construction (OM&C), Virtual Contact Center (VCC), and Zealand employee groups. For OM&C, the current agreement ends June 1, 2025. The VCC agreement ends August 1, 2025. The Zealand agreement ends October 1, 2025. Collective bargaining agreements expire every five years for OM&C (Operating Maintenance and Construction), CCC (Customer Contact Center) and Zealand employee groups. For OM&C, the current agreement ends June 1, 2025. CCC agreement ends in August 1, 2025. Zealand agreement ends October 1, 2025. Technology changes are required to reflect these new agreements. Otherwise, employees in these union groups may not be paid appropriately or get correct benefits. Completion of this project will provide value to the Company and its customers through: (1) waste elimination by making changes in the software for any pay and benefit changes as required by the new agreements; (2) defect reduction by adding process automation to otherwise manual processes for tracking and recording work, premium, and absence time; and (3) improved employee engagement among the OM&C, CCC, and Zealand union employees. The scope of this project encompasses making any system changes required to support the new working agreement for the OM&C, CCC and Zealand employees. Exact details will be finalized after the negotiation process is completed and contracts are approved. Three alternatives were considered for this project: (1) Make no system changes after the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, union grievances, significant manual processes leading to greater possibility of error, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances. (2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs. (3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievances. Option (3) was chosen because it leverages current SAP technology, automates what would otherwise require manual processing, and is the least costly option.	2025-04-24	2026-02-02	-1.00	-	58,546		-	-	-	-	-	-	-	34,806	-	-	6,401	28,405	-	-
2	2025	Application Currency-Corporate-O&A	Software(Intangible)	Corporate	The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	247,951		-	-	-	-	-	-	-	153,681	7,387	-	77,304	68,991	-	-
3	2025	Asset Accounting Upgrade 2025-202	Software(Intangible)	Corporate	The project will upgrade our current accounting asset management software to the latest version as required by the vendor and implement additional new features, ensuring continued support of a critical financial application, and providing new functionality. In 2027, standard vendor support ends for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility. This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; and (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor software from the current version to the newer version. Alternatives considered include: (1) Evaluate SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and FiveTech Plan, it would be more complex, cost more, and not provide all the required features. (2) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) Upgrade to the newest version of current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.	2025-06-18	2026-08-28	-1.00	-	566,275		-	-	-	-	-	-	-	174,802	-	-	20,295	154,508	-	-
4	2025	Product Family Enhancements-Corp	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	665,241	3,130		456,156	-	-	173,696	233,480	-	48,979	1,940	-	-	84	1,856	-	-
5	2025	Product Family Enhancements-Corp	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	357,471		-	-	-	-	-	-	-	221,562	-	-	43,678	177,885	-	-
6	2025	Talent Management Enablement	Software(Intangible)	Corporate	The project will deliver technology solutions to enable best-in-class Talent Management programs and processes that are critical to achieve the Company's overarching Talent Strategy Plan. The Talent Strategy Plan is a key enabler of the company's Integrated Resource Plan (IRP), Electric Distribution Infrastructure Investment Plan (EDIIP), and Natural Gas Delivery Plan (NGDP). Effective Talent Management programs and processes are critical to develop the skills, capabilities, productivity, and experience necessary to successfully execute these plans that deliver clean, reliable, affordable energy through an exceptional customer experience. Significant technology improvements are required to transform Human Resources (HR) to develop the skills and capabilities necessary to achieve the Company's strategic destination. Currently, many Talent Management processes are manually managed with little or no technology enablement. Specifically, the talent compensation processes are mostly manually done outside the system which introduces waste, and a potential for errors. In addition there is a limited visibility of competency gaps within the workforce. The Company cannot effectively place talent in accelerated development programs aligned to competency gaps, nor can it recognize and motivate employees for quickly increasing competency and performance. Furthermore, the Company operates in an increasingly competitive job market where candidates and employees expect best-in-class processes, technologies and experiences relative to their employment and career development. The lack of full technical enablement across Talent Management programs poses a risk to employee attraction, retention and limits the ability to develop the right skills at the right time to deliver on Company strategies. This project will add value to the Company through technology that will enable: (1) fully functional integrated compensation module; (2) accelerated and targeted talent development of critical skills necessary to deliver on the Company's commitment to clean energy and exceptional customer experience; (2) transparency into talent and skill gaps in order to identify retention and service delivery risks within critical areas, as well as inform succession and hiring strategies; (3) improved knowledge transfer, business continuity, and customer service during a time when retirement eligibility is high and risk of knowledge loss has the potential to negatively impact customer service and satisfaction; and (4) increased efficiency and quality of talent management through simplified and automated processes that reduce costs associated with recruiting, onboarding, and developing employees. Talent Management Enablement will deliver the best-practice technology to enable and enhance (1) Fully functional integrated talent compensation management; (2) Simplified and automated talent management process for employee lifecycle management from on-boarding through Off-boarding; (3) Succession Planning and Business Continuity; (4) Career Development and Employee Retention;. The scope will include: (1) implementation of each system/application; (2) integration with current systems, applications and processes as applicable; (3) retrofit current systems and applications to ensure a seamless end-to-end experience of HR processes; (4) delivery of mobile capabilities for in scope processes; (5) reporting and analytics dashboards and report insights for in scope processes. These alternatives were considered for these Talent Management programs and processes: (1) Develop custom, internally built solutions that could meet most requirements. This alternative was not selected because a custom solution would result in higher overall costs, higher maintenance costs, fewer upgrades, and would not leverage industry best practices to ensure best-in-class delivery; (2) Select an on-premise software tool. This alternative was not selected because it requires internal maintenance, increases infrastructure costs, and would have less frequent upgrades which would hinder the Company's ability to ensure processes are evolving alongside industry trends and best practices. (3) Evaluate and select cloud/SaaS solution(s) which would have lower infrastructure costs, less internal maintenance than an on-premise solution, and would be built and evolved with upgrades based on industry best practices. Based on research, internal experience with successful best practice implementations, and vendor demonstrations, option three was selected.	2023-09-07	2025-01-26	-1.00	377,372	486,075		65,532	-	-	4,439	58,790	-	2,303	63,347	-	-	14,218	49,129	-	-
7	2025	Total Information Management (TIM)	Software(Intangible)	Corporate	The project will replace the existing Total Information Management (TIM) on-premise solution with a cloud-based OpenText Software as a Service (SaaS) solution. It will provide the Company with the ability to reduce operational costs for performing upgrades and maintenance, take advantage of new enhancements offered by the vendor, and ensure continued support of the platform. The existing on-premise Total Information Management (TIM) solution hardware and software is at end of support. The state of the current infrastructure creates security, stability, and reliability risk for the platform. Without vendor support, the application no longer receives security patches, bug fixes, or functionality support from the vendor, which creates additional security, stability, and reliability risk. This project will provide value to the Company through: (1) reducing costs with cloud allocated hardware scalable to current usage needs; (2) reducing operating costs with vendor managed feature updates and maintenance provided without service disruption; (3) providing access to new and innovative capabilities; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) migrating, upgrading, and transforming the dataset to the latest version of OpenText Extended Enterprise Content Management (xECM) Cloud Edition and deploying in the vendor hosted cloud; (2) migrating on-premise documents to the vendor hosted OpenText Core Archive cloud; and (3) enabling new functionality including a new user interface, new workflow capabilities, new workgroup management features, and new integrations with Microsoft 365 applications. Alternatives considered include: (1) Defer to a future date. This alternative was not selected due to requiring upgrades of existing on-premise hardware, impeding our ability to take advantage of new features offered by the cloud solution, and reducing cost savings opportunities presented by moving to the cloud. (2) Deploy OpenText on-premise solution to new on-premise hardware. This alternative was not selected due to cost associated with purchasing new hardware, cost associated to maintain, and it does not free up internal resources to focus on other value-added initiatives. (3) Select and migrate to a new vendor software. This alternative was not selected due to the cost, effort, and complexity of replacing the platform with a whole new technology. (4) Migrate to the OpenText cloud platform. This alternative was selected due to it building on the Company strategy of moving to cloud, reducing operating and maintenance costs, and it reduces risk by ensuring consistent, seamless vendor support.	2025-03-10	2026-01-27	-1.00	2,754,880	512,955		1,889,021	1,376,261	-	98,571	321,272	-	92,916	317,932	254,796	-	11,748	51,388	-	-
8	**SUBTOTAL**	**2025 Corporate**										**2,410,709**	**1,376,261**	**-**	**276,706**	**613,543**	**-**	**144,198**	**968,071**	**262,183**	**-**	**173,727**	**532,161**	**-**	**-**
9	2025	Application Currency-CX&O-Capital	Software(Intangible)	Customer	Prior period adjustment.							(8,911)	-	-	(4,714)	-	-	(1,196)	-	-	-	-	-	-	-
10	2025	Application Currency-CX&O-O&M	Software(Intangible)	Customer	Prior period adjustment.							-	-	-	-	-	-	-	2,565	-	-	2,565	-	-	-

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	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
11	2025	Customer Order Service Tracker	Software(Intangible)	Customer	Short cycle orders including gas emergencies and meter services account for many of the incoming customer inquiries to the contact centers. This project will implement a service order status tracker to provide transparency to customers and oversight to internal teams supporting utility service orders across Company service areas. The tracker will provide timely and accurate service order updates, creating a more robust customer experience for tracking service order status and location-based updates. Customers have limited visibility to when Company assigned crews will be on premise and what work will be completed. This is due to features missing within the Company's digital channels for accurate updates from dispatch, scheduling, and field crews. The lack of awareness drives calls into the call center, resulting in approximately 346,000 annual contact center calls related to short cycle requests. Additionally, this lack of visibility increases truck rolls due to dispatchers being unaware of crew locations and routes which can cause crews to be assigned when a local crew could have completed the work. This leads to overall customer dissatisfaction because of a lack of visibility to scheduled and ongoing short cycle work. Enabling a digital channel for communication regarding utility service orders will improve customer experience and reduce the waste of repetitive crew dispatching. This project will add value to the Company and its customers by: (1) providing transparency for customers on the timing and location of the associated crew completing utility service orders, (2) reducing calls to contact centers by customers seeking clarification regarding arrival times through visibility to scheduling time-frames and providing notifications to customers when crews are enroute, (3) improving resource assignment by current location, which decreases wasted truck rolls through enabling location services for active crews, (4) increasing visibility into the service person(s) completing the order by enabling crews to connect with customers through digital channels, and (5) improving customer experience for short cycle service orders by implementing a channel of choice for Company interactions. The scope for the project includes: (1) modifying the customer self-service portal to include features that support utility service order tracking, including the location of crews enroute, (2) providing desktop and mobile capabilities, (3) enhancing the existing ServiceBench platform to allow real-time status updates that can be communicated to customers, (4) utilizing location-based services to update internal portal in real time, and (5) enabling text and email notifications to alert customers of service crews arrival times. Alternatives considered for this project include: (1) Deploy a mobile application to address utility service order tracking, (2) utilize a cloud hosted solution from a third-party, (3) modify the existing customer portal to enable customers and the Company to track utility service orders and crews. Options one and two were not selected as the cost associated with deployment would greatly outweigh the benefits with call reduction and improved customer experience. The third option was selected because it utilizes existing technologies, which reduces the implementation complexity and project cost and has faster value realization for the customer and the Company.	2025-01-01	2025-12-31	-1.00	3,382,089	881,140		388,818	-	-	9,502	375,601	-	3,716	127,534	-	-	1,540	125,994	-	-
12	2025	Energy Assistance Enhancements ar	Software(Intangible)	Customer	The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy (CARE) project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interfaces and updates to SAP to process various requests. Upcoming modifications will be identified following an ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services (DHHS) and Michigan Public Service Commission (MPSC) to prioritize the list of changes. Each grant year, DHHS and MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track active CARE customers, and how they will administer the Michigan Energy Assistance Program (MEAP) benefits through bill credits and arrears forgiveness. The criteria changes significantly each year; therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requirements are not fulfilled, the Company is at risk of losing state Low Income Home Energy Assistance Program (LIHEAP) funds to assist low-income customers with paying their energy bills, thereby increasing the customers risk of shutoff for non-payment. In addition, our energy assistance programs function within all software platforms in the company which consistently need enhancements and updates. The project will provide the following value: (1) complete modifications to internal SAP application and Agency Portal to receive LIHEAP funding, which can be used to provide customers the bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LIHEAP funding; and (3) complete modifications to customer facing platforms. The project scope includes: (1) updating the enrollment and status process; (2) allowing for flat monthly bills; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and Michigan Public Service Commission; (6) updating CARE dunning process; and (7) updating CE PASS functionality to enhance Agency Self-Service. Alternatives considered included: (1) continue with current process, which would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization, which would remove ownership and visibility into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. Option 3 was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems (SAP, Agency Portal, etc.) , therefore a cloud or third party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.	2025-01-01	2025-12-31	0.00	-	293,972		-	-	-	-	-	-	-	182,205	-	-	108,246	73,959	-	-
13	2025	Enhancements - Customer Experien	Software(Intangible)	Customer	The CX&O initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the CX&O Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT technology investments for CX&O. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	354,329	68,530		242,963	-	-	102,084	110,577	-	30,302	42,475	-	-	5,050	37,425	-	-
14	2025	Enhancements-CX&O-O&M	Software(Intangible)	Customer	The CX&O initiative will utilize O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort technology changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing technology requires a short timeframe between inception and implementation. Failure to make these changes or to update aging technology can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of technology enhancements in the CX&O Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work technology efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT technology investments for CX&O. The scope of technology enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	205,253		-	-	-	-	-	-	-	127,217	-	-	36,209	91,008	-	-
15	2025	Genesys Cloud Migration	Software(Intangible)	Customer	The project will migrate the Company's existing on-premise customer contact solution and deploy it to the Genesys Platform As A Service (PAAS) cloud-based solution. It will provide the Company with the ability to reduce operational costs for performing upgrades and maintenance, take advantage of new enhancements offered by the vendor, and ensure continued support of a critical customer communication channel. In 2028, standard vendor support ends for the current on-premise contact center software and extended support is not available from the vendor. Without vendor support, the application no longer receives security patches, bug fixes, or functionality support from the vendor, which creates security, stability, and reliability risk. With the upcoming end of standard support, the vendor is no longer offering feature enhancements to the current on-premise solution limiting the Company's ability to invest in new ways to better serve its customers. This project will provide value to both the Company and its customers through: (1) reducing costs with cloud allocated hardware scalable to current usage needs; (2) reducing operating costs with vendor managed feature updates and maintenance provided without service disruption; (3) providing access to new and innovative capabilities to enhance customer service; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) deploying the new PAAS cloud-based solution in the vendor cloud environment; (2) installing a new internet circuit to directly connect the Company's systems to the vendors cloud environment; (3) updating existing customer interactive voice response (IVR) system to accommodate the new cloud implementation; and (4) implement new features supporting analytics, quality, and reporting. Alternatives considered include: (1) Defer to later years. This alternative was not selected due to requiring upgrades of existing on-premise hardware, impeding our ability to take advantage of new features offered by the cloud solution, and reducing cost savings opportunities presented by moving to the cloud; (2) Deploy Genesys on-premise solution to new on-premise hardware. This alternative was not selected due cost associated with purchasing new hardware and does not address the security, stability, and reliability risk resulting from the vendor end of support for the on-premise software. (3) Select and migrate to a new vendor software. This alternative was not selected due to the complexity of our existing internal integrations between the Genesys platform and the Company's other internal systems. As a result, selecting a new system with a new vendor would make the switch cost prohibitive. (4) Migrate to the Genesys Cloud platform. This alternative was selected due to it building on the Company strategy of moving to cloud, reducing operating and maintenance costs, and reduces risk by ensuring consistent, seamless vendor support.	2024-06-25	2025-12-19	-0.80	-	181,298		-	-	-	-	-	-	-	19,132	-	-	9,487	9,644	-	-
16	2025	Product Family Enhancements-Cust	Software(Intangible)	Customer	The Customer initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	2,490,803	417,046		1,707,944	92,697	-	184,697	1,325,221	-	105,328	258,487	-	-	31,765	226,722	-	-
17	2025	Product Family Enhancements-Cust	Software(Intangible)	Customer	The Customer initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	17,892		-	-	-	-	-	-	-	11,090	-	-	991	10,099	-	-
18	2025	Rate Change Maintenance	Software(Intangible)	Customer	The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements. For the Company to continue to meet and comply with the Michigan Public Service Commission (MPSC) rate change requirements, there is a need to make periodic updates/modifications to the existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers. The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that includes new surcharges, price changes, and energy efficiency programs. The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC, and (2) optimizing the rate configuration in the Company's back-end system for more efficient rate changes. Alternative considered include: (1) a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and the timing it would take for testing of this model; and (2) leverage onshore resources to plan, coordinate, and execute the rate changes. This option was selected as it supports the Company's operation model for rate changes.	2025-01-01	2025-12-31	-1.00	-	301,644		-	-	-	-	-	-	-	186,960	-	-	14,372	172,589	-	-
19	2025	SiteCore Primary Upgrade 2025	Software(Intangible)	Customer	The project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for consumersenergy.com website, a channel many customers use for accessing account information and bill payment. Sitecore is currently operating on version 10.3, which is due to end mainstream support at the end of 2025. If this occurs, there will be an increase in support and maintenance fees of 10% above the annual subscription spend. The project will add value for the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to-date security posture; and (3) supporting the Company's CXi goals by improving reliability and performance. The project scope includes: (1) upgrading the Sitecore content management software to include content hosting and delivery allowing the use of new features and functionality; (2) migrate the Sitecore platform to the most up-to-date hardware and software by refreshing the application and database servers to a newer version of Windows Server and SQL Server. Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the current version falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Undergo a full website redesign. This solution was not chosen as a similar effort is already slated to begin in 2024; and (3) Upgrade Sitecore on a two-year cycle. This alternative was chosen as it provides up-to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.	2025-05-30	2026-04-30	-1.00	-	117,201		-	-	-	-	-	-	-	44,372	-	-	36,376	7,995	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST-BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
20	SUBTOTAL	2025 Customer										2,332,814	82,697	-	290,568	1,811,299	-	138,150	1,802,038	-	-	346,602	755,436	-	-
21	2025	Ransomware Recovery-OT-Electric I	New Computers / Hardware	Electric	This project will implement a multi-layered security approach to our production OT data center backups to mitigate data loss risk from a ransomware attack for both IT and OT. As an American energy provider, the company is at an increased risk of ransomware attacks by nation-states and other advanced threat actors. A severe ransomware attack could leave the Company without access to critical data or processes and little to no ability to recover the associated systems and information. In a best-case scenario, a successful ransomware attack would likely result in primary systems outages, severely limiting our capability to provide services to our customers, for up to a week and could result in months of work to recover auxiliary systems. This project will add value to the Company, and its customers, by: (1) Implementing a 3-2-1-1-0 (3 copies, 2 media, 1 offline, 1 immutable/air) strategy to protect the production data center systems, data, and backups from ransomware and broader potential cyber-attacks; (2) Providing a diverse set of restoration options to reduce data loss and improve the recovery time of mission-critical systems; (3)Mitigating the risk of complete data loss by storing backups offline and in a format that cannot be modified by any threat (internal or external); (4)Defining an OT-specific ransomware recovery plan that the Company can use to respond to a wide array of cyber-attacks with a practiced process; and (5) Providing the ability for OT to sever all communications from the industrial control systems to the public internet and corporate IT networks. The scope of this project is to deliver one-day of hardware storage level recovery points, local immutable copies of production OT data, an offline third copy of production OT data, and deliver a ransomware recovery plan with a scenario-based approach to ransomware response including plans for monitoring, testing, containment, ransomware/malware removal, and full system recovery. The project team looked at a number of alternatives to assure ransomware recovery capabilities: 1.)Paying the associated ransom, a plan to pay the ransom introduces unnecessary risk by either trusting the attacker to provide the encryption keys while taking a financial loss or the regulatory ramifications such action would result in. 2) Restoring from tape is a possibility but significantly increases OT's restoration times in the event of a severe ransomware attack (over one week to restore mission-critical systems). 3) Restoration from the public cloud was considered but delivery would have been extremely complex and capabilities are limited in ransomware recovery situations due to public Internet connections being severed to the OT datacenter when a ransomware attack is identified (Island Protocol). 4) The alternative chosen was to host ransomware capabilities in the CE OT datacenter. This solution provides enhanced recovery times and uninhibited restoration of mission critical systems.	2024-01-10	2026-02-10	-1.00	5,184,139	70,010		618,140	15,123	154,688	274,006	103,478	-	70,845	3,476	-	-	3,467	9	-	-
22	2025	Application Currency-Electric-O&M	Software(Intangible)	Electric	The Electric/Generation/Renewables Engineering and Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric/Generation/Renewables Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Electric/Generation/Renewables Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company.	2025-01-01	2025-12-31	-1.00	-	352,808		-	-	-	-	-	-	-	352,808	-	-	116,632	236,176	-	-
23	2025	Cascade Modernization and Prioritiz	Software(Intangible)	Electric	The project will add additional features and enhancements to Cascade, the High Voltage Distribution (HVD) team's asset management database, which includes HVD line switches, all substation and mobile substation equipment and some Low Voltage Distribution (LVD) equipment. These new capabilities will improve the efficiency, add automation and visualization of these assets. The Cascade Asset Management Database is currently lacking in two areas. 1) It does not currently have reporting for visual management that will show Asset Health. This results in not being able to prioritize equipment inspections and maintenance which causes wasted effort by operators spending time on the wrong equipment; and 2) integration to the Company's SCADA (Supervisory Control and Data Acquisition) system. Substation Operators inspect substations on a monthly/bi-monthly basis. Inspections require manual data entry that is already being collected by SCADA. Consequently, operators spend more time and effort on inspections focusing on data entry tasks rather than on meaningful inspection of equipment. Completion of this project will provide value to the Company through: (1) providing visual management using standard and customizable reports which will allow the Company to make data driven decisions; (2) establishing a link between equipment and SCADA which will allow anomalies to be detected and alerts to be sent to the team. This will automate data collection for substations inspections; and (3) allow visual management to be updated daily to reflect Asset Health status and be able to prioritize maintenance. The project scope includes: (1) installing the Connect module to Cascade; (2) installing the Insight module to Cascade; (3) securing a connection to the PI Historian server; (4) installing on-premise web server; and (5) creating additional dashboards. Alternatives considered included: (1) Breaking the scope into separate projects to be completed individually. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work efforts resulting in higher costs. (2) Do nothing. This alternative was not selected because the Company is not able to evaluate the equipment to the best of its ability allowing the team to make the best decisions. (3) Combining the work efforts for both initiatives into a single project to realize the most potential. This alternative was selected because it provided the best balance between achieving the project objectives and controlling the cost. Installing both solutions will allow visual management to be updated daily to reflect Asset Health status and the ability to prioritize maintenance.	2024-07-12	2025-08-25	-1.00	518,898	41,408		231,592	219,360	-	61,257	(77,384)	-	28,359	35,380	-	-	4,318	31,062	-	-
24	2025	Catastrophic Crewing (CatCrew) Ver	Software(Intangible)	Electric	The Catastrophic Crewing (Cat Crew) Version 2.0, formerly known as Catastrophic Crewing Database Replacement, will significantly overhaul and enhance the Catastrophic Crewing application, which is the software used during storms to manage storm resources and logistics, as well as key pieces of equipment during storm restoration. The current features of the Catastrophic Crewing are not meeting the continually changing expectations for the speed of service restoration for the increasing number of impactful storms in Michigan. We are unable to see and track resources or storm data accurately. There is a significant amount of manual processes, which include hotel reservations tasks, external crews assignments, and ICS on-call schedules that need weekly identification and analysis. There is an opportunity for approximately 4,000 hours of automation annually identified from these processes. The current system is not easy to use or intuitive. The data and reporting history is not accurate or up to date. There is significant potential for human error in the current system, which in turn creates a large volume of waste and increases possible risk to the public and field crews. The project will add value by: (1) streamlining the procurement of internal and external resources during storm conditions; (2) providing accurate information regarding hazard conditions and resource deficiencies; (3) enabling real time updates and safety visibility of all resources in the field; (4) reducing human struggle with office and field resourcing tasks (Ex.: with securing accommodations/hotel reservations); (5) improving reporting accuracy and reducing troubleshooting and data validation; and (6) improving resource management. The project scope includes: (1) identifying requirements for Catastrophic Crewing Application Enhancements; (2) developing, configuring, and testing interfaces, hardware, and software for the solution; (3) implementing the solution and process for the following work groups: Electric High-Voltage Distribution (HVD), Electric Low-Voltage Distribution (LVD), Mutual Assistance, Forestry, Restoration Management, and Storm Teams; (4) change management; (5) building system controls for validating that all required data entry is entered; (6) enhanced logic to automate callout for storm responders; (7) enhancing database exporting and reporting functionality; (8) error-proofing entries for all resources through data validation in the application; (9) archiving all resource data; (10) implementing functionality to identify the status of Forestry, Damage Assessment, Wire Down, and all other field resources in each area; (11) training resources on new technology and processes; and (12) automation of lodging capabilities for crews. The considered alternatives were: (1) continue with the current system and processes, not chosen due to its inability to allow timely, data-driven resource management for improved customer service and field resource safety; (2) replace the current system with a new one capable of addressing issues, not chosen because, the off-the-shelf product didn't meet all requirements, the product's cost was excessively high compared to enhancing the existing Cat Crew Management Application, and high support/maintenance cost; (3) divide the scope into separate projects, not chosen due to interrelated efforts leading to potential duplication of work and potentially higher costs, and (4) a complete overhaul and enhancement of current system. This alternative was selected because it minimizes duplication of efforts, maximizes identified benefits in operating and cost savings; and with minimal increase in ongoing application operational cost.	2024-02-09	2026-06-26	5.02	3,332,475	221,671		1,758,467	-	-	486,277	1,072,880	-	199,311	5,454	-	-	5,408	45	-	-
25	2025	Electric Geographic Information Syst	Software(Intangible)	Electric	This project will replace the existing design software for Electric Low Voltage Distribution (LVD) with a new solution that will be fully integrated to the ESRI (Environmental Systems Research Institute) GIS (Geographic Information System) platform which is already in use by the Company. This new solution will leverage GIS asset data to generate engineering designs. This will allow the Electric teams to have a single source and format to view asset data, construction drawings and redlines in both the back office and field. This change will further enable improvements to the mobile platform in quality of data that is used by the closeout team. This will also reduce the back end posting effort by using the native GIS data format; improving data quality by reducing the re-keying of data. The current design software creates waste in three areas for many teams within Electric including Low Voltage Distribution (LVD) Engineering, Field Leaders, and Customer Energy Management (CEM) Service Designers. (1) The current software does not support the native GIS data format and will not support future enablers which manage network management needs. This causes waste and room for error by having to redraw designs in GIS that have already been created and prevents optimization of the work process. (2) It is not able to integrate to SAP to automatically order materials based on the design. (3) The current software lacks needed mobile functionality due to its lack of support for the native GIS format. The designs are not georeferenced to the exact location and can't fully utilize redlining capability which causes a significant impact to data quality and crew performance. This project will add value to the Company and its employees through: (1) eliminating the need to duplicate all design work so it is in both the design system and GIS, (2) enabling mobile editing and redlining on the design in GIS, (3) enabled integration to SAP, and (4) utilizing the capabilities of the next generation GIS platform that will be delivered through an in-progress business case. The project scope includes: (1) installing a new solution that will integrate to GIS; (2) utilizing GIS geospatial and asset information data and the GIS platform for generating Electric LVD engineering designs; (3)integrating to and from SAP to automate Compatible and Mass Unit material ordering capability; (4) installing new and upgrading existing geospatial platform infrastructure to support additional users (Electric LVD designers, Field Leaders, Planners, Schedulers, etc) of GIS; (5) integrating to ProjectWise (engineering content management system); (6) configuring mobile toolset; (7) re-engineering the existing GIS data model to handle asset life cycle; and (8) configuration for new ArcGIS services. Alternatives considered include: (1) enhance existing software to be able to connect to GIS and SAP. This option was not selected because it is not native functionality in the current software. This would be extremely expensive to develop and implement; (2) continue with current solution. This option was not selected as the current software and data format hinders all downstream work and asset management workflows. This adds additional effort, technology costs, and will keep the Company from reaching its corporate competitiveness goal; (3) implement a GIS based solution. This alternative was selected because a new solution will utilize existing geospatial platform on-premise and will move the Company to a single data format that will enable both field and back office employees.	2025-09-09	2029-02-22	-0.31	6,241,626	659,758		-	-	-	-	-	-	-	759	-	-	183	576	-	-
26	2025	Electric Infrastructure Attachments	Software(Intangible)	Electric	Prior period adjustment.							1,795	-	-	-	1,795	-	-	-	-	-	-	-	-	-
27	2025	Generation Operations Digital Work I	Software(Intangible)	Electric	The project provides durable mobile devices for Ludington Pumped Storage, and mobile software and digital forms for Electric Generation at Ludington Pumped Storage and Renewable Generation. The current work management process for Electric Generation at Renewable Generation sites, and Ludington Pumped Storage is cumbersome and largely paper based. Information is currently buried in SAP, may not be complete and is not easily searchable. This system leads to process waste, re-work, and human error. An electronic mobile software will better capture maintenance, condition of equipment, provide visibility to data and records including regulatory tracking while working on equipment, and create a digital punch list for future work. This project provides value to the Company through: (1) Productivity is improved and human struggle reduced by simplification of work tracking through the mobile software. Time sheet charging is incorporated to the work order when someone on the crew pushes the clock to start versus being separately entered through SAP Employee Self Service. If there is more than one person on a crew, information is entered for the full crew versus individually, including time tracking. Functionality is available to more easily create a digital punchlist in the field when a worker sees something instead of later writing it on a punchboard and entering it separately into SAP. (2) Employee Engagement improves as the more tech savvy candidate pool for these positions are looking for mobile software to help them do their jobs. (3) Quality is improved by creating a digital punchlist when the technicians find an issue versus manually documenting it later. Accuracy increases and rework decreases when updates are performed right at the time and place of the work instead of afterwards. Productivity can also be tracked and measured for further improvements. This level of tracking is not possible with the current process and information. (4) Safety is improved as employees have remote access to manuals to reference before moving forward with and during their work. The access to manuals increases productivity and better supports error reduction training by having the manuals available so a worker can move beyond "I think" and "I believe". The project will mitigate the risk of work and safety errors from using outdated procedures. (5) For Renewable Generation, the improved maintenance program will reduce equipment downtime resulting in an increase to Megawatt hours produced. (6) For Ludington Pumped Storage, the new mobile devices will allow working with electronic Systems Operations Management System (eSOMS) which will improve productivity and reduce non-premise time. The scope of the project includes: the initial roll out for Electric Generation at Ludington Pumped Storage, and Renewable Generation, which would include: (1) purchase of mobile field devices for Ludington Pumped Storage, (2) purchase of additional mobile work management software licenses, (3) development and configuration of forms and workflow for these groups, and (4) enhance wireless connection at Ludington Pumped Storage. Alternatives considered include: (1) Utilize an SAP work management mobile solution. An SAP work management solution is not preferred since it is a new solution and requires additional project and support cost. (2) Continue the manual paper-based process. Continuing the manual paper-based process was not chosen because of process waste, re-work, and human error. (3) Customize the existing electronic Shift Operations Management System (eSOMS) mobile application to add work management functions. A custom eSOMS mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the eSOMS product was not intended to support. (4) Utilize an out of the box solution to minimize cost and risk to the Company and its employees. The combined Service Suite and digital form solution is the preferred option because it is a proven solution and provides the mobility and digital benefits at a lower cost than other alternatives.	2024-07-24	2026-01-18	-1.00	381,810	25,656		308,330	-	-	144,560	132,383	-	31,387	21,161	-	-	7,806	13,355	-	-
28	2025	HVD Supervisory Control and Data A	Software(Intangible)	Electric	The Electric High Voltage Distribution Monitoring System Upgrade project upgrades the software and hardware components of the High Voltage Distribution (HVD) Supervisory Control and Data Acquisition (SCADA) system. This system is used to monitor and control generation, transmission, and high voltage distribution voltage circuits. The upgrade will provide new functionality and enable new capabilities. Running on an older version of the HVD Software could have potential impacts on the reliability and resiliency of the low voltage distribution (LVD) system as well as the HVD system, as distribution reliability metrics depend upon HVD system availability. Maintaining an older version of the software and hardware creates risks associated with vendor responsiveness in addressing problems, as they arise. It will also take more effort to support any upgrades in the future because of difficulties resulting from longer durations between upgrade efforts. If upgrades are delayed, additional full-time resources will be required for the year upgrades occur to address upgrade complexities. Upgrading the HVD SCADA software and hardware adds value to the Company by ensuring that problems are promptly addressed when they occur. Additionally, the upgrade includes enhancements and fixes to the core product that support the resiliency of electric delivery, ensuring that customers are receiving the energy they need when they need it. Also, the distribution system depends on availability of the HVD system, staying current with the solution provider upgrades is critical to the resiliency of both systems. The scope of this project is an upgrade to the HVD SCADA software and hardware, which encompasses the following: (1) upgrading the application software; (2) upgrading the underlying application hardware; (3) implementing new functionality for improved value to the Company; (4) making necessary configuration changes; and (5) updating documentation related to the integration changes. Alternative considered include: (1) Defer the biennial upgrade of the SCADA application and its hardware. The Company targets SCADA biennial application upgrades to stay within two versions of the current application state to maintain application stability and cyber security, given the critical nature of the SCADA system. This alternative was not chosen due to increased security risk and need for vendor support of the application. Additionally, the hardware is already past the end of its useful life and has been moved over to a 3rd party warranty provider. (2) Alternative Vendor solution. This option was not chosen because the move from our current vendor would be time consuming and costly. It could also introduce instability as any alternative solutions have not been proven operationally. (3) Do nothing. This option was not chosen due to the critical nature of these systems and the potential operational risks associated with operating on an unsupported solution. (4) The option chosen is to complete the upgrade project with associated hardware and software necessary to complete the project that will deliver new functionality for improved value.	2025-04-07	2026-12-31	-1.00	3,442,113	213,929		849,601	414,669	420,716	2,283	11,280	-	653	127,424	600	48,524	-	78,301	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(l)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
29	2025	Live Wiredown Detection and ADMS	Software(Intangible)	Electric	The Live Wiredown Detection and ADMS Upgrade project, formerly known as Live Wire Down, enables, configures, tests, and implements an add-on module to the ADMS/Electra outage management system that provides the Company with the information on whether a wiredown has a live conductor or not, enabling dispatchers to prioritize truck-rolls and wire-guards to the live wiredowns first. The module provides this information based on any smart meter events being reported from behind that conductor. An upgrade to the ADMS system to the next version 3.4 is required to enable the Live Wiredown Detection module. The ADMS 3.4 version also contains several other functional enhancements the benefit the overall Electric service restoration process. Currently, the Company does not have the ability to remotely determine if a reported wire down is live. Therefore, the Company has to send truck-rolls to secure every location. Sometimes, it is a waste of time and resources for the public safety teams (police & fire) guarding a downed wire that may already be de-energized. There is no way currently to determine the priority of which wiredown the restoration team should be tending to. There are major public safety concerns around wire down operations as well as the logistics of team safety during wiredown operations. The Live Wiredown Detection module from the vendor requires an upgrade to version 3.4 of the current ADMS software. Therefore, this project would warrant an upgrade of the existing version 3.2 to new version 3.4 of the ADMS software, which itself comes with new functionality and several enhancements. The project will add value by: (1) reducing the number of truck-rolls, (2) relieving public safety personnel from downed wires quicker, (3) reducing the size of the wire down operations teams, (4) decreasing wiredown secure times, (5) implementing the ability to prioritize wiredowns, (6) gaining efficiency in resourcing and lean time spent troubleshooting, (7) meeting MPSC-regulatory standards, and (8) creating the ability to reduce isolating and enable restore or repair safer, faster, and cheaper. The scope of the project includes: (1) upgrade of the existing version 3.2 to new version 3.4 of the ADMS software, (2) turning on the "Live wire conductor" and other new functionality in the ADMS system, (3) testing the new functionality in various possible scenarios, (4) enabling the wiredown tool and other enhancements for all Low-Voltage Distribution (LVD) locations across the Company, and (5) communicating and training users on the new functionality. The alternatives considered are: (1) Developing an in-house application that provides process improvements. This option was not selected as it requires the Company to design and build the algorithm that the Electric Power Research Institute (EPRI) has already devised, and then integrate with the OMS system; (2) Using the LVD line sensors (to be deployed in 5 years) to provide some of the functionality. This option was not selected as the benefits realization would be much delayed; (3) Maintaining the current truck-roll process. This option was not selected due to the specific MPSC-regulatory standard expectations and the safety implications of doing nothing; and (4) Enabling and implementing the live wiredown module for OMS. This option of enabling and implementing the live wiredown module for OMS integrates with the new OMS system and is based on the algorithms that EPRI has already designed. This option was chosen as it has the least technology and integration risk, which avoids the need for the Company to develop their own logic and algorithm for live wiredown detection.	2025-01-01	2025-12-31	-1.00	1,582,898	116,702		-	-	-	-	-	-	-	79,279	-	-	52,136	18,143	-	-
30	2025	Product Family Enhancements-Elect	Software(Intangible)	Electric	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software & hardware and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	631,426	57,212		631,426	-	-	66,771	517,123	-	47,533	57,212	-	-	32,958	24,254	-	-
31	2025	Product Family Enhancements-Elect	Software(Intangible)	Electric	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	105,585		-	-	-	-	-	-	-	105,585	-	-	23,969	81,616	-	-
32	2025	Streetlight Outage and Restoration C	Software(Intangible)	Electric	This project will optimize the Streetlight Outage and Restoration (SOAR) application to better meet our customers need. The SOAR application is used by the Company's customers to report streetlight outages. This project will add new functionality to meet our customers' needs. While 98% of our customers are using SOAR to submit issues, between 15-20% of those issues are more than a lightbulb change/luminaire replacement, leading to multiple truck rolls, and work requiring long cycle scheduling. It lacks the most current source data due to manual process of updating the data, automation, and SMS text messaging, which leads to work and customer dissatisfaction. By integrating these optimizations, Consumers Energy will streamline the work management system, reduce errors and provide a more comprehensive and efficient solution for our customers, our schedulers and our field workers. This project creates value for the Company by: (1) improving customer and municipality communications; (2) adding visualizations to improve accuracy and speed of repair; (3) adding field improvements such as getting the issue to the right department the first time and knowing what materials are needed so the light is fixed on the first visit; and (4) automating and updating the map which will allow for more accuracy. All of these will eliminate waste by using automation and properly routing of orders. The project scope includes: (1) identifying correctly outages versus other work; (2) improving GIS data to include proper stock material and Temporary Traffic Control (TTC) requirements and prioritizing scheduled work based on outage repair needs; (3) offering SMS text messaging; (4) improving email communications by including more accurate details to customers; (5) daily automation of map data updating; (6) adding functionality for user-generated reliability reports; and (7) adding a new process to advise municipality of extended repair outages. The alternatives considered include: (1) continue the manual process. This includes adding municipality-owned lighting layers to the Company's GIS solution, updating streetlight asset information and updating of the SOAR map. This option was not selected as it is heavy in human error and waste resulting in additional costs. (2) Purchase a new system. This option was not selected as it would be extremely expensive to purchase and wouldn't have all of the requirements needed. (3) Implement technology improvements. This alternative was selected because it will improve customer communications, improve accuracy and speed of repair.	2025-09-08	2026-10-29	-0.99	1,860,161	448,127		652,802	-	-	35,122	607,935	-	9,745	338,119	-	-	7,041	331,078	-	-
33	2025	Transmission Outage Application (TC	Software(Intangible)	Electric	This project will modernize and streamline the high voltage system outage process, substation asset management, construction management and maintenance processes, as well as the high voltage project management process by replacing obsolete systems with an industry standard alternative and providing future integration opportunities with corporate systems. The current software version is no longer supported by the vendor and does not allow for the enhancements that would increase the functionality of the software. Also, the solution is susceptible to human error and duplication of efforts due to the manual nature of the work. Lastly, the ongoing support of the software is also costly and time consuming due to the outdated version and the requirements for the process solution. The project will add value by: (1) simplifying the process of managing and rescheduling large HVD projects; (2) enhancing the ability to quickly identify conflicts created by schedule changes; (3) allowing the Company to internally support future integrations with existing applications; (4) improving resource management and visibility by planning Substation Construction, Substation Operations, and High Voltage Distribution (HVD) Lines reasources by project; (5) implementing ability to plan Control Center reasources based on planned work and control center capacity; (6) improving visibility and repeatable reporting for defects and problem solving; (7) simplifying communication with stakeholder groups including Low Voltage Distribution (LVD) Scheduling, Business Customer Solutions, Electric Field Lab, and Substation Operations for outage requests requiring resource coordination; and (8) including 24x7 application support and patching due to using a Cloud solution. The scope of the project includes: (1) upgrading to the newest version of software for a real-time electric operations application; (2) migration of applications and data to cloud servers, and (3) end-user testing. The alternatives considered for the project include: (1) continuing with the current system and processes. This alternative was not selected because the current version is out of support, is prone to human error and duplication, and is costly to maintain. (2) breaking the project into separate Company built applications. This alternative was not selected because the individual applications would have integration complications and support issues, as they would all be separate entities. (3) purchase an off-the-shelf cloud option. This alternative was selected as it would not have customization of the base product or integration issues and comes with 24x7 cloud support.	2025-09-08	2026-07-31	-0.93	861,864	276,556		349,051	115,000	-	-	230,400	-	3,651	12,880	-	-	12,313	568	-	-
34	**SUBTOTAL**	**2025 Electric**										**5,481,160**	**764,165**	**575,404**	**1,070,277**	**2,599,843**	**-**	**591,464**	**1,130,537**	**666**	**48,524**	**266,231**	**815,183**	**-**	**-**
35	2025	Application Currency-Electric & Gas	Software(Intangible)	Electric & Gas Shared	The Electric and Gas Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	106,648		-	-	-	-	-	-	-	66,101	-	-	16,400	49,701	-	-
36	2025	Application Currency-Operational Te	Software(Intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	43,025	-		29,502	-	-	23,110	60	-	6,332	-	-	-	-	-	-	-
37	2025	Application Currency-Operational Te	Software(Intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	39,732		-	-	-	-	-	-	-	24,626	-	-	17,363	7,263	-	-
38	2025	Application Currency-Operations-Ce	Software(Intangible)	Electric & Gas Shared	Prior period adjustment.							1,659	-	-	4	-	-	1,655	-	-	-	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
39	2025	Customer Consecutive Estimate Red	Software(Intangible)	Electric & Gas Shared	The project will resolve gas and electric accounts with consecutive estimates due to the service being disconnected and customer's usage being estimated. Consumers Energy experienced two show cause orders from MPSC for consecutive estimates and fines of $500,000 in 2016 and $1M in 2023 including $3M that is to be refunded to the customers from the money that is recovered from the vendor. If the funding is not recovered from the vendor, the total fine would result in $4M as the Company is responsible for the difference between the dollars recovered from the vendor and the $3M total established by MPSC. The project objective is to reduce disconnected consecutive estimate accounts from 8% to less than 1% reducing non-compliance regulatory risk with MPSC rules. The project scope includes enhancing account and work management digital solutions to properly reflect disconnected account status. Process improvements were put into place after the 2016 show cause; however, increased electric meter failures, supply chain shortages, and a project focused on replacing meter technology due to the sunset of 3G communication led to issues that resulted in a second show cause order. Do nothing does not improve the customer experience. Our current solution of SAP CRM used by Call Center, SAP Work Management, ADMS for Storm and Service Suite for Field Work are all core platforms able to accomodate the change. Adding additional software or alternatives will complicate the technical solution and/or require additional training for Call Center & field personnel.	2025-03-10	2026-01-27	-1.00	711,907	98,300		48,140	-	-	3,124	43,811	-	1,205	21,085	-	-	1,744	19,341	-	-
40	2025	Enhancements-Operations-Capital	Software(Intangible)	Electric & Gas Shared	The Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Operations Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	122,361	-		83,903	-	-	8,887	72,877	-	2,139	-	-	-	-	-	-	-
41	2025	Field Contractor Work Management	Software(Intangible)	Electric & Gas Shared	The project provides the ability to electronically manage contractor work and increases accuracy and timeliness of information processing for field work deliverables. This project additionally creates new opportunities to measure and optimize field work processes supporting customer on-time delivery goals. Contractor field employees use manual, paper-based processes and generic communication technologies (phone, radio, email, collaboration sites) to perform work for the Company. Due to the non-electronic format, inaccuracy, and delay of information processing there are negative impacts to the availability and accuracy of work status. This limits the opportunity to measure and optimize field work processes that support customer on-time delivery and other goals. The project will add value by: (1) improving on-time delivery of customer work by providing electronic work order information to contractors; (2) improving customer satisfaction through efficiency in scheduling work and reporting on the progress electronically; (3) increasing safety by tracking work and contractor status providing visibility into the last known location of the contractor; (4) improving material management; (5) making it easier to move emergent work to contractors to balance workloads and meet customer commitments; and (6) enabling real time updates to work order information, increasing data accuracy and reducing invoice reconciliation time. The project scope includes: (1) identifying requirements for a Bring Your Own Device (BYOD) field contractor work management technology solution and process; (2) developing, configuring, and testing interfaces, hardware, and software for the solution; (3) implementing the solution and process for the following work groups: Electric High-Voltage Distribution (HVD), Electric Low-Voltage Distribution (LVD), Mutual Assistance, Forestry, Gas Distribution, Gas Code Compliance, and Substation Operations Construction/Metric; (4) updating the following vendor contract types to support BYOD field contractor work management: zone, specific bid, ancillary, electric storm, and mutual assistance; and (5) training field contractors on the new technology and processes. The alternatives considered included: (1) Continue with the current paper-based process. This alternative was not selected because this approach does not allow for the timely, data-driven work management metrics required to improve service to customers. (2) Use the current Company mobile application. This alternative was not selected because the solution is not expected to receive long term investments by the vendor and the mobile application would require more upfront investment than the proposed option. (3) Use off-platform options such as ServiceBench. This alternative was not selected because contractors would not be able to leverage the benefits and integrations with the existing platform and it would require additional new integrations. (4) Provide Company-funded field devices to contractors. This alternative was not selected because the investment in hardware, management of on-boarding and off-boarding of devices to contractors, and training and change management is cost-prohibitive and introduces a risk of the loss of control of information security and corporate assets. Leveraging the existing field work management solution was chosen because it uses existing well-developed functionality while leveraging cloud-based, BYOD capabilities to move short-term and long-term contractors from paper processes to the established, standard work management system.	2021-05-24	2025-04-28	-0.85	1,730,358	742,196		31,196	-	(2,676)	28,178	-	-	5,694	1,116	-	-	922	5	-	189
42	2025	Field Mapping and Graphics	Software(Intangible)	Electric & Gas Shared	This project will implement a solution for the mobile field mapping and data collection that can search and view facility map data, view work order designs, and create work order as-built construction drawings in the field. This software technology increases process efficiency by consolidating field graphics functionality, reducing IT complexity and testing, and increasing adoption in the field through ease of use. In addition, it allows the Company to move to a supported application platform and retire the unsupported ArcPad solution. The current mapping and graphics application was implemented in 2002 and is no longer sold or supported in any capacity, and the customizations developed for the application cannot be changed. Due to the improved accuracy of the CE landbase (streets, political boundaries, etc.), the outdated electric maps that are referencing that data causes the map to be unreadable which causes a safety issue. Additionally, field employees have considerable challenges when attempting to use the software due to slowness, an aged interface, and dated processes. The project will add value by: (1) providing more accurate geospatial data, including facility map data, pre-construction designs, and as-built construction drawings; (2) consolidating daily tasks into a more simplified process; (3) eliminating the process waste from duplicating asset data in two systems; (4) enabling the adoption of the Geographic Information System (GIS) standard; and (5) making mapping and graphics data available on field devices. The project scope includes: (1) installing a new mobile field mapping and graphics application; (2) creating the ability to search and view the facility map data in GIS format along with the ability to search by address; (3) viewing pre-construction work order designs in a new GIS format; and (4) creating as-built construction drawings in GIS format for assigned work orders. Four alternatives were evaluated and three were determined non-viable for the project: (1) Continue maintaining the current ArcPad application. This option was not selected because the Company is no longer able to make changes to the ArcPad application to mitigate issues if the application has critical defects. A total failure of the application could revert field crews back to paper-based facility maps, risking safety using static, outdated data; or require the creation of as-built construction drawings on paper documents. (2) Use the Adobe or Snagit applications for creating as-built construction drawings. This option was not selected because field users would have to use one solution for viewing facility maps and use rudimentary drawing tools like Adobe or Snagit for creating as-built construction drawings. This option was also not selected because it introduces additional costs due to the complexity and customization needed to integrate the applications. (3) Build a custom Mapping and Graphics solution. This option was not selected as existing industry solutions are available at a much lower cost with much less risk. (4) Implementing the new field mapping and graphics software was selected as this option will consolidate field graphics functionality into an efficient process and provide a current, supported solution.	2021-01-05	2026-03-23	-0.72	3,991,705	135,200		101,698	-	-	20,407	37,069	-	44,222	35,864	-	-	23,190	12,607	-	67
43	2025	OSIsoft PI Historian Upgrade 2020	Software(Intangible)	Electric & Gas Shared	Prior period adjustment.							(74,184)	(26,464)	(12,681)	-	(35,059)	-	-	(7,030)	41,213	11,372	-	14,435	-	-
44	2025	Product Family Enhancements-Elect	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Companys ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	3,359,801	484,922		2,303,815	52,051	90,421	392,758	1,639,772	-	128,813	300,557	-	-	99,936	200,424	-	197
45	2025	Product Family Enhancements-Elect	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Companys ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	1,361,912		-	-	-	-	-	-	-	844,120	-	-	92,572	751,543	-	5
46	2025	Spatial Asset Management	Software(Intangible)	Electric & Gas Shared	This initiative will implement SAP's Spatial Asset Management module. It will allow users to view assets, notifications, and orders geospatially using a map. The module will allow us to create and maintain asset maintenance plans for each segment of our gas and electric distribution networks (linear assets). We will create linear assets as technical objects (such as functional locations and equipment) and store linear data. We will enable creation of maintenance plans for these technical objects which result in notifications, maintenance orders, and measurement documents. We will enable monitoring the condition of our linear assets, identify where there is damage or a defect (using the start point and end point and offset), and manage all types of maintenance tasks (planned, unplanned, and preventative). Currently Consumer Energy lacks spatial visualization and spatial awareness of work and assets impacting requirements for first time quality and impacting the ability to plan, bundle and execute nearby work. The lack of a linear asset management capability affects the full work management value stream resulting in overproduction of asset maintenance activity such as assessments, surveys, and inspections. This project creates value for the company by 1) providing capability in SAP to view assets, notifications, and work orders on a map, 2) providing location awareness in SAP for assets and work, 3) establishing linear asset management capability in SAP for gas and electric delivery networks, 4) enabling end-to and map-based workflows. The scope of this project encompasses implementation in SAP of the Spatial Asset Management module. Alternatives considered include: 1) A Cloud-based individualized asset integration between GIS and SAP. This alternative was not selected as it proves ineffective in addressing needs of the end-to-end work management value stream while increasing the technical footprint of customization. There are also performance concerns with cloud to on-prem integrations. 2) Work group centric approaches to viewing work on a map. This alternative was not selected as it does not support standard operation thru the entire work management value stream. 3) Do nothing. This alternative was not selected as this would enable increasing costs and inefficiencies in gas and electric work management. 4) The alternative to implement the Spatial Asset Management module in SAP was chosen as it expands use of a core technology investment, supports current investment in our work management value stream, and is compatible with our GIS technology.	2024-05-10	2026-06-26	-1.00	2,861,655	97,619		226,180	-	-	7,266	112,356	-	106,558	15,862	-	-	2,455	13,408	-	-
47	2025	Work Management Scheduling Analy	Software(Intangible)	Electric & Gas Shared	The project will implement a solution to optimize the key components of the Distribution Planning and Scheduling functions including forecasting, work order intake, resource identification, work schedule creation, work execution preparation and associated work order analytics. The Distribution Planning, Scheduling and Administrative Support & Financial Services (Work Plan Strategy) teams are utilizing manually intensive work methods, systems and forecasting models. These inefficiencies impact the creation of work plans, lack predictive capacity planning, and reduce productivity of operational partners. The project will add value by providing: (1) streamlined processes tied to workload review and preparatory analysis, leading to increased focus on workload priority, execution of work and a reduction of human struggle; (2)increased accuracy in crew work schedules, leading to improved customer satisfaction and on-time delivery of customer requested work, system integrity work, and gas compliance requirements; (3) reduced manual scheduling steps, reporting and analysis of data associated with work management processes and systems; thereby minimizing the risk of human error hours spent developing and updating crew route sheets; and (4) improved forecasting accuracy, that results in greater transparency into the weekly schedule and associated work plan. The project scope includes: (1) implement a solution to facilitate the review of work orders from various engineering organizations, allowing for streamlined check-in of work orders; (2) implement a scheduling tool that utilizes predictive modelling and advanced analytics and streamlines daily schedule modifications; (3) enhance integration with the Aros application to bring in employee capacity and availability information; (4) integrate with SAP to retrieve work order data and manage record keeping requirements; (5) enhance integration with Field Service Suite (FSS) for quicker access to MISS DIG information and work order assignments; and (6) implement associated analytics and reporting. Three primary alternatives were considered for this project: (1) Automating manual data movement across excel and current systems through Robotic Process Automation. This option was not chosen because it will not meet base requirements and will not provide desired insights into whether the schedule supports operating priorities and metrics, financial scenarios, first time completion of work, and daily goals; (2) Integrating an off-the-shelf planning and scheduling system. This option is not preferred due to associated up-front and long-term costs; and (3) Implementing a hybrid of an off-the-shelf planning component with custom built scheduling functions. This is the preferred option to provide a more cost-effective and targeted fit for the organization.	2022-01-26	2025-12-29	-1.00	1,932,038	212,118		35,562	-	(177)	7,306	22,071	-	6,361	29,851	-	160	-	29,691	-	-
48	**SUBTOTAL**	**2025 Electric & Gas Shared**										**2,787,911**	**6,456**	**74,587**	**491,040**	**1,912,047**	**-**	**302,981**	**1,400,203**	**41,213**	**11,532**	**254,582**	**1,098,417**	**-**	**458**
49	2025	ARP-Infoblox Refresh	Network	IT/Digital Foundation	This project will replace the three legacy core components, Domain Name System (DNS), Dynamic Host Configuration Protocol (DHCP), and Internet Protocol Address Management (IPAM) also referred to as DDI (DNS, DHCP, IPAM) environment with a modern, vendor supported system. Infoblox is the DDI solution that the Company uses to enable seamless network communications across critical systems. When Infoblox Assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with Security updates. Consumers Energy also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. The value of this program includes: (1) enabling the Company to efficiently manage and control their networks, and (2) providing Domain Name System (DNS), Dynamic Host Configuration Protocol (DHCP), and Internet Protocol Address Management (IPAM). The scope of this project includes the replacement of DNS, DHCP and IPAM assets on a 5-7 years refresh cycle. The alternative considered was to continue operating on existing Infoblox equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes. The alternative to replace the existing Infoblox equipment with the latest hardware and software provided by the vendor was selected to avoid these risks and continue a regular refresh cycle.	2025-01-01	2025-12-31	-1.00	393,288	7,271		203,605	-	200,738	2,020	243	-	604	4,507	-	-	4,495	12	-	-

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Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
50	2025	ARP-Local Area Network	Network	IT/Digital Foundation	This project will upgrade the Company's entire LAN and a significant portion of the Wireless Local Area Network (WLAN). At some Company locations, LAN equipment has been in service since 2011. If the LAN/WLAN hardware and software is not routinely refreshed, the Company will lose the manufacturer support needed for equipment bug fixes, security vulnerability patches, and enhancements. In addition, aging equipment cannot accommodate the increasing demand for wireless devices necessary to perform day-to-day operations that rely on wireless-enabled devices, such as rugged field devices, cell phones, barcode scanners, tablets, and other mobile devices. As equipment ages, it is at risk of higher failure rates, which increases the risk of unplanned outages. In the event of unplanned outages, business areas would not be able to access services on the corporate network including email, SAP, internet, and phones. The project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor supported, thereby ensuring support for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; (6) increasing user productivity through a higher performing wireless network, which increases the productivity and efficiency of office and field employees serving customers; and (7) improving support for wireless Internet Protocol (IP) phones, Internet of Things(IoT) and field devices. The project scope includes: (1) refreshing the LAN equipment and software across all Company sites; (2) identifying the required features for the new equipment; (3) implementing the new equipment according to industry best practices; (4) replacing wireless network with upgraded infrastructure and verifying wireless coverage is as expected; and (5) collecting wireless survey data for all Company locations in order to design improved wireless network coverage. The alternative considered was to continue operating on the existing platform past the vendors end-of-support date. The vendor support period ended in May of 2021, and paying for extended support is not an option offered by the vendor. The risk inherent in not refreshing the platform is a lack of vendor support resulting in an absence of software bug fixes, security updates, and break fixes. The Company chose to replace the existing equipment with the latest hardware and software available, following a five year refresh cycle.	2025-01-01	2025-12-31	-1.00	737,964	100,199		382,044	33,827	(67,218)	149,056	229,383	-	37,196	62,104	-	56,580	3,252	2,011	-	260
51	2025	ARP-Radio	Network	IT/Digital Foundation	This project will refresh hardware to include; 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices and vehicle consoles in service trucks. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 7-year lifecycle basis. Cellular modems are refreshed on a 5-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle. Vehicle consoles are typically retired with the vehicle but are salvaged for reuse in new vehicles when possible. 800MHz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customers service and critical infrastructure. Company radio systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing. The refresh of these subscriber units in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety. This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure. The project scope consists of: (1) scheduled replacement of radios and modems and consoles; and (2) installing additional radios modems and console assets to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters. The alternatives considered included: (1) Replace the existing units with new units from other radio and modem manufacturers; (2) purchase new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.	2025-01-01	2025-12-31	-1.00	1,499,439	165,149		776,260	-	827,499	14,014	(57,380)	-	(7,873)	102,360	-	71,279	6,273	9,518	-	15,290
52	2025	Application Currency-IT/Digital Foun	New Computers / Hardware	IT/Digital Foundation	The Application Platforms initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	21,188		-	-	-	-	-	-	-	13,132	-	-	12,753	379	-	-
53	2025	ARP-Collaboration	New Computers / Hardware	IT/Digital Foundation	This project will replace the Company's obsolete or out-of date audio, visual, telephony and other communication collaborative tools and equipment. When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value by: (1) ensuring that the Company's audio, visual, telephony, and other communications systems are stable and reliable; and (2) retiring the legacy enterprise Avaya telephone systems that have reached end of mainstream manufacturer support. The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for evolving business requirements. The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only. These alternatives were not chosen due to the risk inherent with a partial replacement of assets, which includes: (1) a reduced supply of equivalent replacement Avaya parts that are no longer being produced; and (2) an erosion of the knowledge technicians possess on discontinued systems.	2025-01-01	2025-12-31	-1.00	922,771	516,440		632,744	4,937	508,639	21,755	93,849	-	3,564	320,092	18,100	228,414	5,134	68,438	-	6
54	2025	ARP-Field Device Asset Management	New Computers / Hardware	IT/Digital Foundation	This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility. When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices prior to increasing hardware failures; and (2) allowing field workers to complete their job tasks. The project scope consists of replacing field device assets according to the four-year refresh cycle. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for field devices; and (2) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the assets that need refreshing in future years based on the number of devices that were not replaced during the four year refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle to alleviate these concerns.	2025-01-01	2025-12-31	-1.00	2,400,742	(82)		1,646,189	-	1,623,447	3,836	17,761	-	1,144	(51)	-	(4)	-	(47)	-	-
55	2025	ARP-Operational Technology Suppo	New Computers / Hardware	IT/Digital Foundation	The Asset Refresh Program (ARP)-Operational Technology (OT) Support Common project will replace dated and obsolete servers shared by Electric and Gas on a rotating five-year refresh schedule. When Operational Technology Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure. The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure.	2025-01-01	2025-12-31	-1.00	1,769,128	170,400		1,213,091	626,767	549,295	16,924	15,682	-	4,423	105,615	-	48,203	554	56,857	-	-
56	2025	ARP-Operational Technology Suppo	New Computers / Hardware	IT/Digital Foundation	The Asset Refresh Program (ARP)-Operational Technology (OT) Support Electric project will replace dated and obsolete servers on a rotating 5 year refresh schedule. When Operational Technology Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure. The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five to seven-year refresh cycle or (2) refresh hardware based on a five to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five to seven-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety for customers, as vendors do not provide extended support after seven years. The Company chose the alternative to refresh this hardware based on a five to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Electric SCADA.	2025-01-01	2025-12-31	-1.00	213,441	59,643		213,441	118,402	39,223	55,345	(14,096)	-	14,566	59,643	200	9,717	33,170	16,556	-	-
57	2025	ARP-Printer Asset Management (PAI	New Computers / Hardware	IT/Digital Foundation	This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one. When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications. The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unexpected expense for replacement of assets that were still in good operating condition. Anything greater than five years is assessed monthly to ensure it is not run-to-failure, including running the asset to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.	2025-01-01	2025-12-31	-1.00	1,560,027	3,322		1,069,711	-	1,001,931	52,555	19,489	-	(4,264)	2,059	-	-	1,787	208	-	64
58	2025	ARP-Server and Storage	New Computers / Hardware	IT/Digital Foundation	This project will replace or augment server and storage infrastructure for the Company. When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be more challenging to keep current with Security updates. The Company also runs the risk of failure of these assets impacting customer interactions and business operations if it does not adhere to a regular five to seven-year refresh cycle. This project creates value for the Company through: (1) improved stability and availability of business-critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use. The scope of this program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements. The alternatives considered were to purchase extended maintenance, move some of these assets to the cloud with the Digital -Hybrid Cloud and Data Center Migration project, or to replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option.	2025-01-01	2025-12-31	-1.00	345,497	14,256		236,907	144,519	85,889	1,915	4,043	-	540	8,836	-	-	8,813	22	-	-
59	2025	ARP-Workstation Asset Management	New Computers / Hardware	IT/Digital Foundation	This project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates. When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks. The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP in future years based on the number of devices that were not replaced during the four year refresh cycle ; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets; and an eight-year cycle for monitors to alleviate these concerns.	2025-01-01	2025-12-31	-1.00	8,044,233	97,772		5,515,931	-	5,252,176	211,957	10,549	-	41,250	60,599	-	41,872	255	898	-	17,774

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
60	2025	Digital-Hybrid Cloud and Data Cente	New Computers / Hardware	IT/Digital Foundation	This project will optimize data center assets and asset replacement project purchases by migrating or retiring applications out of existing Company and co-location data centers into cloud services, reducing operational costs for running IT services and leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services. The technology currently deployed in the Company's data centers meets many customers' needs today. However, the pace of digital transformation is increasing rapidly, and requirements for applications are evolving faster than the technology in the Company's data centers can respond in a cost-effective manner. These data center constraints lead to longer implementation times, missing capabilities, or reduced functionality in the applications that the Company can deploy. This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective combination of data centers and public cloud services. Specifically, by migrating applications to cloud services, the project will: (1) reduce capacity, hardware maintenance, and security device costs at the co-location data center; (2) reduce hardware maintenance and security device costs at the production data center; (3) enable the ability to scale infrastructure quickly up or down without costly up-front hardware purchases; (4) reduce application risk through cost-effective, scalable infrastructure redundancy and availability; (5) reduce ongoing server and storage asset replacement costs; (6) reduce ongoing networking equipment replacement costs; (7) reduce operational support costs; and (8) enable the use of a vast array of cloud services to support Company applications. The project scope includes: (1) promoting the robust main co-location data center to become the primary data center for on-premise IT services; (2) demoting the Company's production data center to the disaster recovery data center for on-premise IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premise to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying base infrastructure to allow each location (on-premise or in cloud) to function independently; (7) deploying cloud and on-premise cost management tooling and processes; (8) simplifying and optimizing backup and disaster recovery resources and processes using cloud services; (9) implementing additional automation for application deployment and management; (10) changing the operations model for support of cloud-based applications; (11) educating and increasing the skills of IT and other employees in leveraging public cloud services; and (12) transforming IT to become the broker of cloud services for the Company. Alternatives considered included: (1) migrating to public cloud services faster. This alternative was not chosen because the Company's ability to absorb new technologies coupled with the investments the Company has already made in data center equipment would prevent a faster move from being efficient and effective, introducing additional financial risk; (2) migrating to public cloud services slower or not at all. This alternative was not selected because: delaying public cloud services and capabilities coupled with requiring an extension of the life of existing data center equipment creates increased financial and operational risk; and (3) contracting with an outside vendor to provide cloud services to run applications for the Company. This alternative was not selected because industry information shows the option as not yet cost effective or not providing a maturity level that the Company would be able to easily consume with limited in-house experience and expertise in public cloud. The alternative to migrate to a hybrid cloud and data center model was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.	2023-04-02	2026-12-31	0.18	10,913,822	2,440,581		2,726,992	-	(2,126)	885,434	1,611,001	-	232,683	529,504	13,895	-	69,548	446,061	-	-
61	2025	SAP HANA Database Migration	New Computers / Hardware	IT/Digital Foundation	In preparation for SAP's planned end of support for its Business Suite product in 2027, the Company will migrate its existing SAP databases from Oracle to SAP HANA in advance of the required move to S/4 HANA. The Company's SAP applications currently utilize Oracle's relational database management system as their underlying database storage technology. SAP has informed its customers that standard support for its legacy Business Suite (aka ECC) product will end in 2027, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the company will migrate all of its SAP databases off of Oracle and onto SAP HANA. This project lays the groundwork for the company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027. Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures and tools required to manage the newly migrated SAP HANA applications. Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering no other options for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform a direct migration from SAP Business Suite on Oracle to S/4HANA. A direct migration to S/4HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application's functionality would change simultaneously, so this alternative was not selected. (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S/4HANA. It will also require the Company to accept significant risk due to the fact that SAP security patches, application patches and upgrades will not be available upon termination of the SAP maintenance agreement. (3) Migrate to SAP's Software as a Service (SaaS) implementation of S/4HANA. This alternative was not selected because an S/4HANA SaaS migration is a much more disruptive option as the Company's business processes must be adjusted to accommodate functionality differences between ECC and S/4HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. (4) Migrate the SAP databases to HANA prior to implementing S/4HANA. This alternative was selected as it gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process changes required with S/4HANA.	2023-07-27	2026-02-23	-0.83	8,663,011	1,430,090		2,352,303	-	18,977	234,474	1,985,352	-	113,499	253,491	26,733	-	38,690	187,782	-	285
62	2025	Security/OT Field Modernization	New Computers / Hardware	IT/Digital Foundation	This project will implement new infrastructure for accomplishing improved security in the field for OT assets. Gas and Electric technicians are using corporate laptops, to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. Vendors and contractors have access to the Company's critical infrastructure using non-Company laptops. Best practice is to use dedicated laptops to connect to critical infrastructure. The value of this project is deploying dedicated Company OT laptops and associated OT infrastructure that can move between OT locations only and providing a secure environment. This project will procure and configure approximately 130 devices that will be used to manage critical OT infrastructure. The Company reviewed several options to mitigate cyber security risks inherent with the use of standard corporate laptops managing critical infrastructure. The alternatives considered are: (1) Continue utilizing existing workflow of using Corporate domain laptops with software installed; (2) Bring in an outside vendor to design and implement a proposed infrastructure; (3) Complete disallowance of all local access to critical systems; (4) Extending the OT network to remote Company locations; (5) Deploy a dedicated Company OT laptop and OT communications circuits, which includes cellular connectivity. The dedicated OT laptop and communications circuits prevented the best way to secure the critical infrastructure by limiting internet and e-mail access. Vendors and contractors could also utilize these approved dedicated systems for managing infrastructure they help support at Company locations. Based on the analysis performed, the Company chose to deploy a dedicated OT laptop and communications circuits.	2025-02-20	2026-12-30	-1.00	2,117,586	310,431		805,662	21,992	531,851	133,951	82,389	-	35,479	39,305	-	-	36,728	1,527	-	1,050
63	2025	Application Currency-IT/Digital Foun	Software(Intangible)	IT/Digital Foundation	The Application Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms area are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	117,102		-	-	-	-	-	-	-	72,580	17,273	-	4,035	51,273	-	-
64	2025	Application Currency-IT/Digital Foun	Software(Intangible)	IT/Digital Foundation	The Infrastructure Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Infrastructure Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Infrastructure Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	28,957		-	-	-	-	-	-	-	17,948	-	-	17,900	48	-	-
65	2025	AxWay Secure Transport 2024 Upgr	Software(Intangible)	IT/Digital Foundation	Axway SecureTransport is the Company's multi-protocol Managed File Transfer (MFT) gateway for securing, managing, and tracking data file flow for our business partners and external vendors. Files impacting billing, HR, Supply Chain, Finance, Alternate Energy Programs, Front Office, Back Office, Device Management, Outage Management and Business Reporting functions utilize these services. This project will update the platform to the current software version, enabling cost-saving operational enhancements while retaining data security and platform supportability.Ax Axway Secure Transport is the public-facing managed file transfer gateway, maintaining platform version integrity is critical to ensuring it remains secure and supportable in the event of a cyber attack, outage or other critical incident. A prolonged outage or incident, for any reason, compromises the ability of the Company to perform mission-critical business transactions in finance, operations and direct customer support. Upgrading this application also gives the Company the opportunity to properly scale SecureTransport and take advantage of the growing demand for additional, cost-savings features of the tool, such as managing internal Electronic Data Interchange (EDI) transactions. The value this project brings Consumers Energy and customers includes: (1) Addressing known problems and limitations of the current software and hardware platforms. (2) Ensuring continued secure, scalable, and critical data transmission services running through Axway continue functioning. (3) Creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste. (4) Merging/streamlining the company data file transfer services reducing cyber-attack vectors and creates a more easily maintained and monitored security model. The scope of this project includes (1) Upgrading the application and database to the current released and supported versions. (2) Refreshing the underlying application infrastructure by upgrading to the latest operating system and hardware platforms. (3) Enable and test expanded Electronic Data Interchange (EDI) functionality.Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because the Axway SecureTransport platform handles critical Company financial, HR and operational transactions--the risk associated with problems stemming from an outdated and unsupported version is too high. Nor would the waste elimination benefits of using the upgraded Axway platform to start consolidating EDI for CE be realized. (2) Replacing the platform. The estimated project costs and timetable for replacing the business functions currently performed by the existing Axway SecureTransport platform would be extensive, and operationally, it is not well suited for a cloud or hybrid cloud solution. In addition to significant platform, application, implementation and functional testing costs, replacing it would require extensive coordination and testing with all of the internal and external account holders, taking upwards of one calendar year. (3) Upgrading the platform. This provides the Company the most cost-effective alternative, balancing costs, known risks, and even growing business capacity and productivity.	2024-02-27	2026-01-26	-1.00	-	119,834		-	-	-	-	-	-	-	27,258	-	-	5,053	22,205	-	-
66	2025	BizTalk Services Migration and Retir	Software(Intangible)	IT/Digital Foundation	The Microsoft BizTalk application transfers data from one location to another with internal and external software systems and assists with securely communicating sensitive financial data. The project will migrate the BizTalk application services to other existing applications resulting in the retirement of the Biztalk application. Microsoft announcing end of life for this application a replacement is needed to avoid business impact. The current version of Biztalk running at Consumers Energy is already out of mainstream support, if major issues occur within the application, it could disrupt critical business processes. This includes financial concerns such as payroll, account receivable, and other essential operations. Ensuring continuity is vital. This project creates and maintains value for the Company and its customers by migrating the Biztalk services to supported applications already present in the Consumers Energy environment that do have not end of life concerns and can provide the same functionality Biztalk was providing to meet business requirements. This project creates and maintains value for the Company and its customers by: (1) Migrating all current processes from the current application to replacement products. The secure file transport processes will be migrating to the existing Axway Secure Transport platform. The Electronic Data Interchange processes will be migrated to the existing SAP platform. (2) Ensuring current and future compliance with Information Security critical and sensitive data initiatives, such as patching, data encryption, and authentication requirements. (3) Guarantees 7x24x365 vendor support is available to the Company during significant outages by remaining on a version supported by the vendor. Alternatives considered included: (1) Using Azure native services to recreate all of the processes and services Biztalk provided. This was cost prohibitive due to time and effort this would take. (2) Purchasing a replacement product. Not seen as optimal as existing applications are already implemented within Consumers Energy that provide the same capability. (3) Leverage existing applications within the Consumers Energy application portfolio. This option was selected as lowest cost option and also to meet application rationalization goals to eliminate applications that are providing duplicate functionality.	2025-02-28	2026-10-31	0.00	876,410	930,309		-	-	-	-	-	-	-	335,186	-	-	122,437	212,749	-	-
67	2025	Data & Analytics Platform Rationaliz	Software(Intangible)	IT/Digital Foundation	This project will optimize the Data & Analytics system landscape by creating connections, migrating data into the Data Lake in the cloud, and building visualizations from the data in the Data Lake. The IT Data & Analytics legacy systems (SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS) are outdated, inefficient, and becoming duplicative in nature with the introduction of DL 2.0. If these legacy systems are not retired, they will continue to cost the Company money as major investments are needed to maintain and support them. This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources. The project scope includes: (1) the assessment of the existing Data & Analytics platforms including SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organization change management; and (7) the retirement/decommissioning of the legacy platforms and applications. Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company's cloud strategy. (2) Lift and shift these on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces. (3) Migrate all data sources to DL 2.0 and retire legacy systems. This alternative was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.	2025-04-07	2027-12-31	0.22	9,019,671	1,319,807		1,174,008	-	-	447,311	607,218	-	119,479	20,633	-	-	7,042	13,438	-	154

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
68	2025	Digital-Cloud Data and Analytics Plat	Software(Intangible)	IT/Digital Foundation	This project will provide Artificial Intelligence (AI) and analytics in the cloud across the business to uncover new paths to value, faster, allowing the organization to make better decisions and enable delivery outcomes for the NiSPP, Electric Grid Integration, customer programs, and other business needs. The project will additionally establish data governance roles and responsibilities, processes, and implement tools to support best practices across the enterprise. Consumers Energy faces several challenges in the ongoing data modernization journey, which include: (1) legacy data platform operations; (2) long lead times for data exploration and identification of data assets; (3) lack of data ownership and quality, (4) limited data governance best practices across data ownership, access control & security; and (5) heavy dependence on IT for Business Intelligence reporting and analytics. The project will add value by providing data to support business needs by: (1) optimizing data platform operations costs with workflow-based platform infrastructure deployment using pre-built modules and templates; (2) reducing data operations build complexity and data engineering costs through automation; (3) improving data quality and governance that leads to reduced costs of data provisioning, data duplication, and improved data accuracy; (4) streamlining data access requests, management, and governance to reduce risks and support efficiency; and (5) increasing the speed to deliver new data and data capabilities, improving productivity, and improving access to data. This project is an enabler for business areas to use these capabilities to build analytic models for asset and labor optimization that is anticipated to more than offset the project costs. The project scope includes: (1) developing and modernizing the analytics platform in the cloud to allow Consumers Energy to implement new use cases leveraging simplified infrastructure configurations and automated deployment processes; (2) build and deploy data management capabilities, controls, catalog, assets, and data flow; (3) developing data ordering workflows and data access management controls; (4) prioritization and new datasets; (5) simplifying infrastructure configuration; (6) automating deployment processes; (7) enabling data governance tools and processes. Alternatives considered include: (1) Address current pain points in existing on-premise and cloud analytics platforms. This alternative was not selected because the existing platforms requires new investment in licensing and infrastructure, delivery for new capabilities cannot keep pace with demand, still requires investment to address legacy system technical obsolescence, and business areas would not realize asset and labor optimizations. (2) Continue to utilize existing on-premise and cloud analytics platforms. This alternative was not selected because it would not address the current pain points in the existing on-premise and cloud analytics platforms, limiting the Company's ability to have required data and analytics capabilities to improve processes and realize asset and labor optimizations. (3) Implement a new data and analytics platform in the cloud. This alternative was selected because it provides improved analytics capabilities, faster access to data that is critical to improve business process, and reduces technical obsolescence.	2023-04-17	2025-12-29	-1.00	12,253,904	1,308,872		(78,598)	-	-	-	(79,599)	-	1	29,166	-	-	1,438	27,719	-	-
69	2025	Enhancements-IT-Capital	Software(Intangible)	IT/Digital Foundation	Prior period adjustment.							4,787	-	(20,103)	(861)	887	-	36,380	-	-	-	-	-	-	-
70	2025	Enterprise Print - Scan Suite	Software(Intangible)	IT/Digital Foundation	The projects intent is to upgrade the current Enterprise Print and Capture suite for improved data security and integration for the work from home business partner. The company currently maintains a print and capture suite that will have support ending in 2025. Only high-level security patches will be available after this date. The company maintains a fleet of servers that are scheduled to be upgraded. The current print and capture suite is not compatible with the targeted server operating systems. The lack of internal resources requires the company to continue to absorb increased costs to contract administrative personal. This project maintains cost savings achieved by eliminating wasteful print jobs and further enables a productive, and flexible workforce for business partners working remotely. This project also ensures that the latest data transmission security requirements of are met by the solution. The project scope includes: (1) upgrading the current suite to the latest version; (2) consolidating the amount of print servers in the environment; (3) training for company personal to administer the suite; (4) converting all workflows from the current system; (5) implementing remediation for security vulnerability risk; (6) integrating device management with Enterprise Configuration Management Database (CMDB) for asset tracking and monitoring. Alternatives considered: (1) migrating to cloud services. This alternative was not chosen at this time due to maturity levels found with subscription services. (2) other print-scan products. This alternative was not selected as it would required new print and scanning specific to another print-scan product. (3) Print-scan products that were less costs. This alternative was not selected, due to fewer capabilities offered than the current product, which would introduction inefficiencies in the current processes. (4) upgrade current product. This alternative was chosen due to lower overall cost of not requiring new hardware, maturity of current product, and providing same level of capabilities required to support current processes.	2024-03-27	2024-12-31	-1.00	658,588	84,906		21,788	-	-	-	1,770	-	20,019	-	-	-	-	-	-	-
71	2025	Enterprise Service Bus Application 2	Software(Intangible)	IT/Digital Foundation	This project will upgrade and migrate the Business Works developer application to the next version. Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway, be more scalable, secure, and capable of integrating to a service-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of approximately $50,000 annually, this is just temporary coverage and serves only to delay the need for an upgrade. The value this project provides the Company includes: (1) cost avoidance to avoid extensive payments for extend support purposes; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies. The project scope includes implementing current version of all applications that are part of the ESB application, database version, and required database drivers. Alternatives considered included: (1) Accept the annual $50,000 extended maintenance cost. Given the critical nature of this application, it is not recommended to lose maintenance support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meter management. The current implementation of the ESB platform was built with 5 years of growth in mind. This alternative was not chosen due to risk to Company operations , and the additional expense. (2) Replace the on-premise upgrade plan to implement a cloud-based solution. A cloud migration would also take longer to complete, which would put the Company at risk of falling outside of the current vendor support window for the products current version. (3) Upgrade the existing application. This option was selected because it best meets the Company needs for the near future by restoring vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.	2024-10-14	2025-12-26	-0.92	-	314,443		-	-	-	-	-	-	-	186,726	-	-	82,454	104,087	-	185
72	2025	HR Support Pack and Business Soft	Software(Intangible)	IT/Digital Foundation	Prior period adjustment.							-	-	-	-	-	-	-	1,034	-	-	64	970	-	-
73	2025	HR Support Pack and Business Soft	Software(Intangible)	IT/Digital Foundation	The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll. This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company. As this is an upgrade of an existing system, the alternative considered was to delay the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.	2025-02-05	2025-12-31	-1.00	-	239,276		-	-	-	-	-	-	-	148,305	-	-	18,515	129,789	-	-
74	2025	Kubra 4.0 Upgrade	Software(Intangible)	IT/Digital Foundation	Consumers Energy (CE) has the overarching ambition of serving 1 in 3 Low-to-Moderate Income (LMI) customers (currently 1 in 6), while supporting the achievement of clean energy goals and reduction in Uncollectible Expense (UCA). 37% of CE customers are low to moderate income (LMI). Low Income (LI) accounts for 11% and means they are currently in crisis and unable to pay their bill. Moderate Income (MI) accounts for 26% and means they are one financial crisis away from being unable to pay their bill. As part of the LMI effort, we are prioritizing Behavior Based Direct Messaging: Meet the customer where they are, communicate about assistance options based on behavioral indicators, and increase the likelihood of enrollment into meaningful assistance programs ahead of a crisis, and Kubra 4.0 will aid in the success of those LMI goals. To help a customer avoid a crisis before it happens, we need the ability to proactively communicate to them when their behaviors signal the possibility of an issue, some examples being: (1) A customer misses a payment after record of making payments for several months, (2) The auto-pay system receives an insufficient fund ticket alert from the customers' account, (3) Energy use is high, and a bill is projected to be 25-50% larger than usual, and (4) Localized / seasonal triggers such as heat waves, blizzards, and ice storms. Additionally, (5) it's imperative that we're able to test and modify message content that captures the customer's attention, so that we may drive awareness to programs that offer assistance ahead of a crisis. Kubra 4.0 platform is more flexible and configurable to help experimental design & marketing iterate on who/when/what to cut through digital noise. This project creates value for the Company through improving customer communications by providing Consumers Energy (CE) with access to (1) templates and wording changes that previously required expensive Statement of Work (SOW) engagement to deliver and (2) reduce lengthy wait times to implement these aforementioned Statements of Work (SOWs). Finally, (3) this engagement will also introduce 12 net new alert messages, (4) allow for new means of communication and messaging via the mobile app push notification feature, and (5) provide better outage notification reliability and control via Application Programming Interface (API) data transfer instead of Secure File Transfer Protocol (SFTP) data transfer. The project scope includes: (1) 12 net new alerts including 4 for the Shut-off Protection Plan (SPP), missed payment(s), summer event alerting, winter event alerting, and 5 additional alerts to be detailed out during the plan & design phase of the effort based on current low-to-moderate income (LMI) customer communication needs, (2) new template editor as part of the upgraded platform, (3) New Push Notification option available for mobile app which will enable a fast follow enhancement to push notifications through more than just email and text, (4) all other updates and improvements through Kubra 4.0 including use of APIs and other technical improvements, and (5) a new Application Programming Interface (API) built specifically for CE's outage messages for better reliability - instead of the existing file transfer outage information which is less reliable. The alternatives considered include: (1) continue the expensive Statements of Work (SOW) approach for updating each message template and for bringing on any new messages. This would total approximately ~50k per new alert, for a total of 600k for all 12 net new alerts for this effort if pursued individually. This total is not including costs to any existing message adjustments. This alternative was not considered due to the extra cost and overhead. (2) Purchase a new customer communications system. This option was not selected as it would be extremely expensive to purchase and wouldn't have all of the requirements needed and would be a tremendous amount of labor to reintegrate with our existing communication channels. (3) Utilizing Microsoft Dynamics or Riverstar. This option was not selected as it would be a tremendous amount of labor to reintegrate with our existing communication channels nor would either of the platforms fully support the bandwith or channels needed for the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-03-17	2026-03-27	-1.00	335,716	-		225,160	-	-	92,846	106,614	-	25,700	-	-	-	-	-	-	-
75	2025	Product Family Enhancements-Appli	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	293,465	59,854		201,229	10,286	-	58,379	108,013	-	24,551	37,098	-	-	9,251	27,847	-	-
76	2025	Product Family Enhancements-Appli	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	94,861		-	-	-	-	-	-	-	58,795	-	-	35,814	22,981	-	-
77	2025	Product Family Enhancements-Infras	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software & hardware and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	196,032	105,266		134,419	-	-	51,219	61,096	-	22,104	65,244	-	-	19,536	45,708	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
78	2025	Product Family Enhancements-Infras	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	38,308		-	-	-	-	-	-	-	23,744	-	-	8,699	15,044	-	-
79	2025	Software Platform Refresh	Software(Intangible)	IT/Digital Foundation	Prior period adjustment							-	-	-	-	-	-	-	534	-	-	180	353	-	-
80	2025	Tibco API Exchange Gateway Repla	Software(Intangible)	IT/Digital Foundation	This project is looking to retire the API Exchange Gateway within the Tibco ESB and replace it with a new solution called Microsoft Self-Hosted Gateway. The API Exchange Gateway is used by the TECO ESB to integrate to external vendors, all new development will need to be done to integrate this solution.The Tibco API Exchange Gateway is anticipated to be sunset by the vendor, as they have already dropped all development of enhancements for the platform.This project creates value for the Company by: (1) Avoiding the risk of running a project no longer supported by the vendor (i.e. the Tibco Enterprise Service Bus API Exchange module), and (2) Enabling the Company the opportunity to move to a product that is more stable, secure, and usable.The project scope includes: (1) Conducting a RFP to procure a replacement product and work with architecture team to migrate the product. (2) Migrate all current work items to the new platform. (3) Conduct appropriate testing to ensure all Service Level Agreements are met.Alternatives considered include: (1) Evaluating the replacement of the current product with a new product that is not already in the Company environment. This alternative was not selected because it would not be cost effective. (2) Keeping the current application as-is. This alternative was not selected as the vendor for the current platform has stopped all development for this product. (3) Leveraging an existing solution already in the Company environment. This alternative was selected as it avoids multiple solutions with redundant capabilities and avoids costs for supporting and maintaining a second solution.	2023-01-03	2025-03-31	-1.00	177,467	117,000		10,277	-	-	1,613	6,015	-	2,649	4,570	-	-	-	4,570	-	-
81	**SUBTOTAL**	**2025 IT/Digital Foundation**										**19,468,949**	**969,530**	**10,550,128**	**2,433,754**	**4,810,855**	**-**	**713,683**	**2,590,016**	**76,200**	**455,662**	**553,871**	**1,469,004**	**-**	**35,078**
82	2025	ARP-Cyber Security	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions. When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a 3-5 year hardware lifecycle; and (2) performing application upgrades. As part of the review process, the alternatives considered were to: (1) upgrade or replace only those assets identified in the plan; (2) upgrade or replace a portion of the assets identified in the plan. Option 1 was not chosen based on continued refresh cycle for cyber security assets to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. Option 2 was not chosen due to the security risk inherent with not replacing assets as per standard refresh cycles increasing system vulnerabilities, and out-of-warranty repair costs.	2025-01-01	2025-12-31	-1.00	148,380	8,049		76,816	-	(1,852)	51,023	13,734	-	13,111	4,969	-	-	-	4,267	722	-	-
83	2025	ARP-Cyber-Common	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions shared by Electric and Gas. When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades. The alternatives considered include: (1) upgrade or replace only the assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.	2025-01-01	2025-12-31	-1.00	498,985	179,405		258,324	66,832	155,787	7,812	25,935	-	1,958	111,196	26,188	-	1,010	83,998	-	-
84	2025	ARP-Cyber-Electric	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions for Electric. When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades. The alternatives considered include: (1) upgrade or replace only the assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.	2025-01-01	2025-12-31	-1.00	50,016	-		50,016	-	49,820	155	-	-	41	-	-	-	-	-	-	-
85	2025	ARP-Network-Common	Network	Security	This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks shared by Electric and Gas. When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks. The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices. The alternatives considered include: (1) continuing to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.	2025-01-01	2025-12-31	-1.00	41,452	-		21,460	7,879	12,028	-	1,553	-	-	-	-	-	-	-	-	-
86	2025	ARP-Network-Electric	Network	Security	This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks for Electric. When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks. The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices. The alternatives considered include: (1) continuing to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.	2025-01-01	2025-12-31	-1.00	452,230	59,470		452,230	127,255	324,720	196	2	-	57	59,470	59,470	-	-	-	-	-
87	2025	ARP-Physical Security	New Computers / Hardware	Security	The ARP-Physical Security, formerly known as Physical Security Asset Refresh, will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns. The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster responses to emergencies and incidents. This could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage. The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reducing gaps in functionality; and (3) optimize overall system performance. Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems. Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security assets per an asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security incidents and breach resolution, and the inability to meet FERC requirements. The alternative selected maintains compliance, reduces redundancies and gaps in functionality, and optimizes overall performance of physical security systems.	2025-01-01	2025-12-31	-1.00	2,310,334	545		1,584,196	-	1,213,765	31,369	387,146	-	(48,084)	338	-	-	337	-	-	-
88	2025	Application Control Enablement	Software(Intangible)	Security	This project implement a technology called Application Control. Application control, also known as application allow listing, is a security strategy that permits only approved applications to run on a system. This approach helps prevent unauthorized software and malware from executing, thereby enhancing the overall security of the network.The rapid multiplication of unauthorized and potentially malicious applications in the current threat landscape poses a substantial risk to corporate data, network infrastructure, and overall business operations. The Company currently does not have an application control solution to mitigate this threat. Without a robust application control product, unauthorized applications can introduce vulnerabilities into the Company's network, leading to data breaches, malware infections, and other cyber threats. Failure to control application usage on the Company's network can result in non-compliance with industry regulations and standards, potentially leading to legal and financial repercussions. Unmanaged applications can cause system conflicts, performance degradation, and downtime, disrupting business continuity and productivity. Inadequate control over applications in the Company's environment increases the risk of data leakage and loss, compromising sensitive information and intellectual property. Uncontrolled application usage can; (1) lead to inefficient use of IT resources; (2) increase licensing costs for software that should not be installed or leveraged by a particular user or department; and (3) reduce efficiency due to deploying computers with more resources than are required because users are installing unneeded software. This project creates value for the Company by (1) Protecting the Company's IT environment by preventing unauthorized and potentially harmful applications from being installed or executed, (2) Maintaining adherence to industry regulations and standards by controlling application usage. This helps avoid legal and financial penalties associated with non-compliance and ensures the Company meets its regulatory obligations. The project scope includes: (1) implementing a Software as a Service (SAAS) application control solution on all corporate computers and (2) implementing stringent restrictions using high enforcement mode on critical assets to prevent running any unauthorized software. Alternatives considered include; (1) removal of local administrator permissions for all users. This option was not chosen as there are legitimate business uses for users to have the ability to make modifications to their workstations., (2) leverage already existing in place antivirus or endpoint detection and response software. This alternative was not selected as this does not prevent unauthorized installation or running of unauthorized software, (3) implementing a privilege management tool. A privilege management tool is a security solution designed to control and monitor access to critical resources within an organization. It helps protect against cyber threats by ensuring that only authorized users have access to sensitive information and systems. This alternative was not chosen as it does not prevent a bad actor that has established privilege into the Company network to install malicious software., and (4) implement an application control solution. This option was chosen because it meets all of the required use cases which reduces risk to corporate data, network infrastructure, and overall business operations.	2025-03-17	2026-03-27	-1.00	697,320	82,165		478,152	391,240	-	52,730	1,919	-	32,263	50,939	49,584	-	1,352	3	-	-
89	2025	Application Currency-Security-O&M	Software(Intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrade The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade scope applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	205,818		-	-	-	-	-	-	-	127,567	1,128	-	84,378	42,061	-	-
90	2025	Enhancements-Security-Capital	Software(Intangible)	Security	This initiative will use Capital funding to make enhancements to existing technology and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements in accordance with accounting rules. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	404,105	20,152		277,095	92,014	46,408	62,670	37,599	-	38,404	12,490	-	-	11,617	841	-	32

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Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
91	2025	Enhancements-Security-O&M	Software(Intangible)	Security	This initiative will use O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increases support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	301,183		-	-	-	-	-	-	-	186,675	20,875	1,849	103,387	60,564	-	-
92	2025	Mass Notification	Software(Intangible)	Security	Prior period adjustment.							(60,955)	-	(52,600)	(7,900)	(234)	-	(221)	-	-	-	-	-	-	-
93	2025	PII Data Discovery Tool	Software(Intangible)	Security	Prior period adjustment.							-	1,693,164	(1,693,165)	-	-	-	-	-	-	-	-	-	-	-
94	2025	Public Key Infrastructure (PKI) Upgra	Software(Intangible)	Security	Replace on-premise PKI to stay supported by the manufacturer. The existing PKI that issues certificates to IT systems for secure communications needs to be upgraded to stay supported by the manufacturer. If the PKI is not maintained, in the event of a system failure the Company would not have support in recovering. All IT systems requiring secure communications via certificates would go offline within three days. Replace existing PKI with new PKI that is supported by the manufacturer. The project will build and configure the servers necessary to provide Public Key Infrastructure services, put in place physical token management for maintaining security, migrate certificate issuing and management to the new system and decommission the old system. The Company has a limited use service for PKI on the Internet only. (1) The Company looked into expanding the service to include usage on the Company network but found the solution to not be economically viable. (2) The Company also looked at full cloud solutions, but it did not meet the security standards currently being used around physical token use. (3) The Company looked at continuing extended support, however the continuing extended support is not available by the vendor. (4) The Company selected a hybrid solution of part cloud and part on-premise to meet all operational and security compliance requirements. The opportunity is to retain ownership of the keys on-premise prior to evaluating ownership through the cloud.	2024-07-01	2026-01-26	-1.00	1,588,066	409,866		137,120	(9,651)	(18,254)	476	148,177	-	16,372	85,215	40,305	210	-	42,809	-	1,892
95	2025	Saviynt Enterprise Identity Governan	Software(Intangible)	Security	The project will implement Saviynt EIGA module, consolidate Identity Access Management (IAM) functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications. The current version of AccessNow reached end-of-life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and customizations. While beneficial for end users, these integrations increase the risk of system failures, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduces failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention. This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt Enterprise IGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) Minimizing custom code and focusing on configurations only by utilizing out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface. This project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Standardizing processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access system; (4) Addressing issues with aging applications, multiple IAM platforms, integration challenges, and antiquated HR processing. Alternatives considered include: (1) Implementing hot fixes to AccessNow version 8.1.5 to ensure support through mid-2023; (2) Upgrading only the application to current supported version, excluding the new web portal but will include new application functionality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break / fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating AccessNow software.	2024-07-01	2027-10-29	-1.00	6,052,582	577,224		1,360,640	(5,360)	-	326,357	912,012	-	127,632	172,001	4,845	-	45,160	118,225	-	3,770
96	2025	Security Analytics	Software(Intangible)	Security	Prior period adjustment.							-	-	-	-	-	-	-	-	-	-	-	-	-	-
97	SUBTOTAL	2025 Security										4,635,095	2,369,374	31,457	524,888	1,527,843	-	181,533	810,886	202,396	2,059	251,509	349,230	-	5,694
98	TOTAL	2025										37,696,237	5,569,470	11,231,976	5,987,232	13,275,530	-	1,672,028	7,907,753	582,592	517,977	1,746,523	5,019,431	-	41,230
99	2026	2025 Union Contract Changes	Software(Intangible)	Corporate	The Human Resources - 2025 Union Changes project will implement SAP and other system changes required as a result of three collective bargaining agreements which will be renegotiated and ratified. Collective bargaining agreements expire every five years for Operating Maintenance and Construction (OM&C), Virtual Contact (VCC), and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2025. The VCC agreement ends August 1, 2025. The Zeeland agreement ends October 1, 2025. Collective bargaining agreements expire every five years for OM&C (Operating Maintenance and Construction), CCC (Customer Contact Center) and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2025. CCC agreement ends in August 1, 2025. Zeeland agreement ends October 1, 2025. Technology changes are required to reflect these new agreements. Otherwise, employees in these union groups may not be paid appropriately or get correct benefits. Completion of this project will provide value to the Company and its customers through: (1) waste elimination by making changes in the software for any pay and benefit changes as required by the new agreements; (2) defect reduction by adding process automation to otherwise manual processes for tracking and recording work, premium, and absence time; and (3) improved employee engagement among the OM&C, CCC, and Zeeland union employees. The scope of this project encompasses making any system changes required to support the new working agreement for the OM&C, CCC, and Zeeland employees. Exact details will be finalized after the negotiation process is completed and contracts are approved. Three alternatives were considered for this project: (1) Make no system changes after the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, union grievances, significant manual processes leading to greater possibility of error, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances. (2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs. (3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievances. Option (3) was chosen because it leverages current SAP technology, automates what would otherwise require manual processing, and is the least costly option.	2025-04-24	2026-02-02	0.00	-	59,546		-	-	-	-	-	-	-	2,135	-	-	72	2,064	-	-
100	2026	Application Currency-Corporate-O&A	Software(Intangible)	Corporate	The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective databases, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Corporate Services are routinely evaluated to determine if and when upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	374,178		-	-	-	-	-	-	-	235,732	-	-	235,732	-	-	-
101	2026	Asset Accounting Upgrade 2025-202	Software(Intangible)	Corporate	The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application. Standard vendor support will be ending for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complex testing activities and too many version increases at any one time. This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of revisions to be adopted. The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor software from the current version to the newer version. Alternatives considered include: (1) Evaluated SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) Evaluated other software options. This option would introduce new ongoing support costs and integrations and may not provide the regulatory reporting and other needed improvements. (3) Upgrade to the newest version of current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.	2025-06-18	2026-08-28	-1.00	-	566,275		-	-	-	-	-	-	-	179,076	-	-	28,660	150,415	-	-
102	2026	Product Family Enhancements-Corp	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increases support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	1,115,000	248,975		738,576	-	-	515,846	-	-	222,730	156,854	-	-	156,854	-	-	-
103	2026	Product Family Enhancements-Corp	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increases support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	258,193		-	-	-	-	-	-	-	162,662	-	-	162,662	-	-	-
104	SUBTOTAL	2026 Corporate										738,576	-	-	515,846	-	-	222,730	736,459	-	-	583,980	152,479	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST-BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
105	2026	Application Currency-Customer-O&M	Software(Intangible)	Customer	The Customer initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Customer digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Customer are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	57,170		-	-	-	-	-	-	-	36,017	-	-	36,017	-	-	-	-
106	2026	Customer Order Service Tracker	Software(Intangible)	Customer	Short cycle orders including gas emergencies and meter services account for many of the incoming customer inquiries to the contact centers. This project will implement a service order status tracker to provide transparency to customers and oversight to internal teams supporting utility service orders across Consumers' service areas. The tracker will provide timely and accurate service order updates, creating a more robust customer experience for tracking service order status and location-based updates. Customers have limited visibility to when Company assigned crews will be on premise and what work will be completed. This is due to features missing within the Company's digital channels for accurate updates from dispatch, scheduling, and field crews. The lack of awareness drives calls into the call center, resulting in approximately 346,000 annual contact center calls related to short cycle requests. Additionally, this lack of visibility increases truck rolls due to dispatchers being unaware of crew locations and routes which can cause crews to be assigned when a local crew could have completed the work. This leads to overall customer dissatisfaction because of a lack of visibility to scheduled and ongoing short cycle work. Enabling a digital channel for communication regarding utility service orders will improve customer experience and reduce the waste of repetitive crew dispatching. This project will add value to the Company and its customers by: (1) providing transparency for customers on the timing and location of the associated crew completing utility short cycle service orders, (2) reducing calls to contact centers by customers seeking clarification regarding arrival times through visibility to scheduling time-frames and providing notifications to customers when crews are en-route, (3) improving resource assignment by current location, which decreases wasted truck rolls through enabling location services for active crews, (4) increasing visibility into the service person(s) completing the order by enabling crews to connect with customers through digital channels, and (5) improving customer experience for short cycle service orders by implementing a channel of choice for Company interactions. The scope for the project includes: (1) modifying the customer self-service portal to include features that support utility service order tracking, including the location of crews en-route, (2) providing desktop and mobile capabilities, (3) enhancing the existing ServiceMesh platform to allow real-time status updates that can be communicated to customers, (4) utilizing location-based services to update internal portal in real time, and (5) enabling text and email notifications to alert customers of service crews arrival times. Alternatives considered for this project include: (1) Deploy a mobile application to address utility service order tracking, (2) utilize a cloud hosted solution from a third-party, (3) modify the existing customer portal to enable customers and the Company to track utility service orders and crews. Options one and two were not selected as the cost associated with deployment would greatly outweigh the benefits with call reduction and improved customer experience. The third option was selected because it utilizes existing technologies, which reduces the implementation complexity and project cost and has faster value realization for the customer and the Company.	2025-09-08	2026-12-17	-1.00	3,382,089	861,140	ROM	1,864,689	-	-	606,841	695,520	-	562,328	412,686	-	-	192,386	220,500	-	-
107	2026	Energy Assistance Enhancements a	Software(Intangible)	Customer	The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy (CARE) project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interfaces and updates to SAP to process various requests. Upcoming modifications will be identified following an ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services (DHHS) and Michigan Public Service Commission (MPSC) to prioritize the list of changes. Each grant year, DHHS and MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track active CARE customers, and how they will administer the Michigan Energy Assistance Program (MEAP) benefits through bill credits and arrears forgiveness. The criteria changes significantly each year; therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requirements are not fulfilled, the Company is at risk of losing state Low Income Energy Assistance Fund (LEAF) funds to assist low-income customers with paying their energy bills, thereby increasing the customers risk of shutoff for non-payment. In addition, our energy assistance programs function within all software platforms in the company which consistently need enhancements and updates. The project will provide the following value: (1) complete modifications to internal SAP application and Agency Portal to receive LEAF funding, which can be used to provide customers the bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LEAF funding; and (3) complete modifications to customer facing platforms. The project scope includes: (1) updating the enrollment and status process; (2) allowing for flat monthly bills; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and Michigan Public Service Commission; (6) updating CARE dunning process; and (7) updating the assistance portal (CE PASS) functionality to enhance Agency Self-Service. Alternatives considered include: (1) continue with current process. This alternative was not chosen because it would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization. This alternative was not selected because it would minimize ownership and visibility into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. This option was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems such as SAP, a large internal system that supports broad areas of the business, and the Agency Portal, an internally developed web application, therefore a single cloud or third-party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.	2026-01-01	2026-12-31	0.00	-	273,574		-	-	-	-	-	-	-	172,352	-	-	188,736	(16,384)	-	-
108	2026	Product Family Enhancements-Custo	Software(Intangible)	Customer	The Customer initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	2,776,896	196,020		1,839,416	-	5,952	233,160	1,534,278	-	66,026	123,493	-	-	81,660	41,833	-	-
109	2026	Product Family Enhancements-Custo	Software(Intangible)	Customer	The Customer initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	300,284		-	-	-	-	-	-	-	189,179	-	-	125,136	64,043	-	-
110	2026	Rate Change Maintenance	Software(Intangible)	Customer	The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements. For the Company to continue to meet and comply with certain MPSC requirements and to enable it to update its rates when rate changes are approved, there is a need to make periodic updates/modifications to existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers. The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that includes new surcharges, price changes, and energy efficiency programs. The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Customer's back-end system for more efficient rate changes. Alternatives considered include: (1) a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and the time it would take for testing of this model; and (2) Instead, the Company chose to leverage onshore resources to plan, coordinate, and execute the rate changes. This option was selected as it supports the Company's operation model for rate changes.	2026-01-01	2026-12-31	0.00	-	246,373		-	-	-	-	-	-	-	155,215	-	-	155,215	-	-	-
111	2026	SiteCore Primary Upgrade 2025	Software(Intangible)	Customer	The project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for the consumersenergy.com website, a channel many customers use for accessing account information and bill payment. Sitecore is currently operating on version 10.3, which is due to end mainstream support at the end of 2025. If this occurs, there will be an increase in support and maintenance fees of 10% above the annual subscription spend in order to purchase extended support, security updates and fixes will only be made available if the extended support is purchased, and product support for errors or required hotfixes that may impact platform stability will not be available even if extended support is purchased. The project will add value for the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to-date security posture; and (3) supporting the Company's CXI goals by improving reliability and performance. The project scope includes: (1) upgrading the Sitecore content management software to include content hosting and delivery allowing the use of new features and functionality; (2) migrating the Sitecore platform to the most up-to-date "hardware" and software by refreshing the application and database servers to a newer version of Windows Server and SQL Server and placing them into Azure Cloud (PaaS & IaaS); (3) implementing autoscaling App Services within Azure to reduce or increase the amount of compute we are paying for based on the need of the customers (i.e. more compute during storm). Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the current version falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Migrate to Sitecore's cloud SaaS solution. This alternative was not chosen due to the cost/benefit analysis of re-architecting our current Sitecore implementation to facilitate use of their SaaS/PaaS not being viable at this time; and (3) Upgrade Sitecore on a two-year cycle. This alternative was chosen as it provides up-to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.	2025-05-30	2026-04-30	-1.00	-	117,201		-	-	-	-	-	-	-	28,734	-	-	17,951	10,783	-	-
112	2026	20% ROM Adjustment - Customer	Software(Intangible)	Customer	This is for the 20% ROM Adjustment for IT projects							(227,938)	-		(121,588)	(170,304)	-	(515,689)							
113	**SUBTOTAL**	**2026 Customer**										**3,351,168**	-	**5,952**	**718,633**	**2,090,894**	-	**515,689**	**1,117,876**	-	-	**797,102**	**328,774**	-	-
114	2026	Ransomware Recovery-OT-Electric I	New Computers / Hardware	Electric	This project will implement a multi-layered security approach to our production OT data center backups to mitigate data loss risk from a ransomware attack for both IT and OT. As an American energy provider, the company is at an increased risk of ransomware attacks by nation-states and other advanced threat actors. A severe ransomware attack could leave the Company without access to critical data or processes and little to no ability to recover the associated systems and information. In a best-case scenario, a successful ransomware attack would likely result in primary systems outages, severely limiting our capability to provide services to our customers, for up to a week and could result in months of work to recover auxiliary systems. This project will add value to the Company, and its customers, by: (1) Implementing a 3-2-1-1-0 (3 copies, 2 media, 1 offline, 1 immutable) strategy to protect the production data center systems, data, and backups from ransomware and broader potential cyber-attacks; (2) Providing a diverse set of restoration options to reduce data loss and improve the recovery time of mission-critical systems. (3)Mitigating the risk of complete data loss by storing backups offline and in a format that cannot be modified by any threat (internal or external); (4)Defining an OT-specific ransomware recovery plan that the Company can use to respond to a wide array of cyber-attacks with a practiced process; and (5) Providing the ability for OT to sever all communications from the industrial control systems to the public internet and corporate IT networks. The scope of this project is to deliver one-day of hardware storage level recovery points, local immutable copies of production OT data, an offline third copy of production OT data, and deliver a ransomware recovery plan with a scenario-based approach to ransomware response including plans for monitoring, testing, containment, ransomware/malware removal, and full system recovery. The project team looked at a number of alternatives to assure ransomware recovery capabilities. 1) Paying the associated ransom, a plan to pay the ransom introduces unnecessary risk by either trusting the attacker to provide the encryption keys while taking a financial loss or the regulatory ramifications such action would result in. 2) Restoring from taps is a possibility but significantly increases OT's restoration times in the event of a severe ransomware attack (over one week to restore mission-critical systems). 3) Restoration from the public cloud was considered but delivery would have been extremely complex and capabilities are limited in ransomware recovery situations due to public Internet connections being severed to the OT datacenter when a ransomware attack is identified (Island Protocol). 4) The alternative chosen was to host ransomware capabilities in the CE OT datacenter. This solution provides enhanced recovery times and uninhibited restoration of mission critical systems.	2024-01-10	2026-02-10	-1.00	5,184,139	70,010		(130,510)	-	(112,512)	(34,260)	26,252	-	(9,990)	7,796	-	-	7,520	276	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
115	2026	Advanced Distribution Management I	Software(Intangible)	Electric	The Advanced Distribution Management System Upgrade (ADMS) project will enhance operator experience, simplify maintenance, and provide more powerful and flexible system functionalities. These include advancements in Fault Location, Isolation, and Service Restoration (FLISR), waste elimination within Maestro, the introduction of independent line sensors, a redesign of temporary conditions, and will incorporate operational views of schematics. The project will also be replacing the outdated hardware. The current ADMS lacks several critical features and improvements that are essential for enhancing operator experience, system maintenance, fault detection, and response capabilities. The existing system struggles with: (1) the current FLISR functionality does not adequately support complex protection requirements and manual switching steps, leading to inefficiencies and potential errors; (2) operators face challenges with passthrough edits and managing conflicts related to devices with tags or temporary conditions, resulting in frequent system reloads and inaccuracies in the as-operated system; (3) the temporary conditions subsystem is cumbersome to use, hindering efficient operations and the ability to support mobile substation and; (4) the current schematic tools do not provide operational views or the ability to save and share views, limiting situational awareness and usability for operators. These gaps result in operational inefficiencies, increased maintenance efforts, and reduced effectiveness in fault management and system operations. Addressing these issues is crucial for improving the overall functionality, usability, and maintenance of the Distribution Management System. (5) The Company runs the risk of increased failure if it does not regularly refresh the infrastructure. The project will add value by: (1) improving the user interface and overall experience of the operators, (2) increasing the flexibility and configurability of FLISR, allowing for better support of complex protection requirements and improving solutions for manual switching steps, (3) enhancing the usability of schematics, providing operational views and the ability to save and share views for better situational awareness, (4) developing advanced switch order functionality to support more robust and efficient operations, (5) allowing ADMS to pull real time network model from GIS Utility Network and (6) improving stability and availability of business-critical applications by proactively replacing hardware before it fails. The scope of the project includes: (1) replacing ADMS hardware, (2) upgrading the existing ADMS platform to the latest packaged version, (3) adding in the feature improvements for Temporary Condition Redesign, Maestro Conflict Resolutions, Independent Line Sensors, FLISR and Schematics, (4) implementing new extraction tool, (5) testing the new functionality in various possible scenarios, and (6) communicating and training users on the new functionality. Alternatives considered include: (1) using outdated equipment and current version of ADMS. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact the Company's ability to respond effectively in storm situations. (2) Moving to a cloud version of ADMS. This option was not selected as the current public cloud platforms do not offer the high security environment required for the ADMS application. Consequently, the vendor platform was not built for cloud environments. (3) Replacing the hardware and upgrading ADMS. This option was selected to alleviate the above concerns.	2026-03-02	2027-11-11	-1.00	11,035,811	892,993	ROM	2,833,468	15,593	1,091,480	922,829	282,945	-	520,621	388,307	-	-	260,216	128,091	-	-
116	2026	Application Currency-Electric-O&M	Software(Intangible)	Electric	The Electric/Generation/Renewables Engineering and Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric/Generation/Renewables Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Electric/Generation/Renewables Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	321,362		-	-	-	-	-	-	-	321,362	80,145	-	214,502	26,715	-	-
117	2026	Catastrophic Crewing (CatCrew) Ver	Software(Intangible)	Electric	The Catastrophic Crewing (Cat Crew) Version 2.0, formerly known as Catastrophic Crewing Database Replacement, will significantly overhaul and enhance the Catastrophic Crewing application, which is the software used during storms to manage storm resources and logistics, as well as key pieces of equipment during storm restoration. The current features of the Catastrophic Crewing are not meeting the continually changing expectations for the speed of service restoration for the increasing number of impactful storms in Michigan. We are unable to see and track resources or storm data accurately. There is a significant amount of manual processes: which include hotel reservations tasks, external crews assignments, and ICS on-call schedules that need weekly identification and analysis. There is an opportunity for approximately 4,000 hours of automation annually identified from these processes. The current system is not easy to use or intuitive. The data and reporting history is not accurate or up to date. There is significant potential for human error in the current system, which in turn creates a large volume of waste and increases possible risk to the public and field crews. The project will add value by: (1) streamlining the procurement of internal and external resources during storm conditions; (2) providing accurate information regarding hazard conditions and resource deficiencies; (3) enabling real time updates and safety visibility of all resources in the field; (4) reducing human struggle with office and field resourcing tasks (Ex.: with securing accomodations/hotel reservations); (5) improving reporting accuracy and reducing troubleshooting and data validation; and (6) improving resource management. The project scope includes: (1) identifying requirements for Catastrophic Crewing Application Enhancements; (2) developing, configuring, and testing interfaces, hardware, and software for the solution; (3) implementing the solution and process for the following work groups: Electric High-Voltage Distribution (HVD), Electric Low-Voltage Distribution (LVD), Mutual Assistance, Forestry, Restoration Management, and Storm Teams; (4) change management; (5) building system controls for validating that all required data entry is entered; (6) enhanced logic to automate callout for storm responders; (7) enhancing database exporting and reporting functionality; (8) error-proofing entries for all resources through data validation in the application; (9) archiving all resource data; (10) implementing functionality to identify the status of Forestry, Damage Assessment, Wire Down, and all other field resources in each area; (11) training resources on new technology and processes; and (12) automation of lodging capabilities for crews. The considered alternatives were: (1) continue with the current system and processes, not chosen due to its inability to allow timely, data-driven resource management for improved customer service and field resource safety; (2) replace the current system with a new one capable of addressing issues, not chosen because the off-the-shelf product didn't meet all requirements, the product's cost was excessively high compared to enhancing the existing Cat Crew Management Application, and high support/maintenance cost; (3) divide the scope into separate projects, not chosen due to interrelated efforts leading to potential duplication of work and potentially higher costs; and (4) a complete overhaul and enhancement of current system. This alternative was selected because it minimizes duplication of efforts; maximizes identified benefits in operating and cost savings; and with minimal increase in ongoing application operational cost.	2024-02-09	2026-06-26	5.02	3,332,475	221,671		878,838	-	-	230,187	542,093	-	106,559	185,619	-	-	132,317	53,301	-	-
118	2026	Electric Geographic Information Syst	Software(Intangible)	Electric	This project will replace the existing design software for Electric Low Voltage Distribution (LVD) with a new solution that will be fully integrated to the ESRI (Environmental Systems Research Institute) GIS (Geographic Information System) platform which is already in use by the Company. This new solution will leverage GIS asset data to generate engineering designs. This will allow the Electric teams to have a single source and format to view asset data, construction drawings and redlines in both the back office and field. This change will further enable improvements to the mobile platform in quality of data that is used by the closeout team. This will also reduce the back-end posting effort by using the native GIS data format; improving data quality by reducing the re-keying of data. The current design software creates waste in three areas for many teams within Electric including Low Voltage Distribution (LVD) Engineering, Field Leaders, and Customer Energy Management (CEM) Service Designers. (1) The current software does not support the native GIS data format and will not support future enabling work management needs. This causes waste and room for error by having to redraw designs in GIS that have already been created and prevents optimization of the work process. (2) It is not able to integrate to SAP to automatically order materials based on the design. (3) The current software lacks needed mobile functionality due to its lack of support for the native GIS format. The designs are not georeferenced to the exact location and can't fully utilize redlining capability which causes a significant impact to data quality and crew performance. This project will add value to the Company and its employees through: (1) eliminating the need to duplicate all design work so it is in both the design system and GIS; (2) enabling mobile editing and redlining on the design in GIS; (3) enabled integration to SAP; and (4) utilizing the capabilities of the next generation GIS platform that will be delivered through an in-progress business case. The project scope includes: (1) installing a new solution that will integrate to GIS; (2) utilizing GIS geospatial and asset information data and the GIS platform for generating Electric LVD engineering designs; (3) integrating to and from SAP to automate Compatible and Mass Unit material ordering capability; (4) installing new and upgrading existing geospatial platform infrastructure to support additional users (Electric LVD designers, Field Leaders, Planners, Schedulers, etc) of GIS; (5) integrating to ProjectWise (engineering content management system); (6) configuring mobile toolset; (7) re-engineering the existing GIS data model to handle asset life cycle; and (8) configuration for new ArcGIS services. Alternatives considered include: (1) enhance existing software to be able to connect to GIS and SAP. This option was not selected because it is not native functionality in the current software. This would be extremely expensive to develop and implement; (2) continue with current solution. This option was not selected as the current software and data format hinders all downstream work and asset management workflows. This adds additional effort, technologies, costs and will keep the Company from reaching its corporate competitiveness goal; (3) implement a GIS based solution. This alternative was selected because a new solution will utilize existing geospatial platform on-premise and will move the Company to a single data format that will enable both field and back office employees.	2025-09-09	2029-02-22	-0.31	6,241,626	659,758		2,278,224	-	200,000	1,038,422	425,000	-	614,802	351,211	-	70,000	199,707	75,000	-	6,504
119	2026	HVD Supervisory Control and Data A	Software(Intangible)	Electric	The Electric High Voltage Distribution Monitoring System Upgrade project upgrades the software and hardware components of the High Voltage Distribution (HVD) Supervisory Control and Data Acquisition (SCADA) system. This system is used to monitor and control generation, transmission, and high voltage distribution voltage circuits. The upgrade will provide new functionality and enable new capabilities. Running on an older version of the HVD Software could have potential impacts on the reliability and resiliency of the low voltage distribution (LVD) system as well as the HVD system, as distribution reliability metrics depend upon HVD system availability. Maintaining an older version of the software and hardware creates risks associated with vendor responsiveness in addressing problems, as they arise. It will also take more effort to support any upgrades in the future because of difficulties resulting from longer durations between upgrade efforts. If upgrades are delayed, additional full-time resources will be required for the year upgrades occur to address upgrade complexities. Upgrading the HVD SCADA software and hardware adds value to the Company by ensuring that problems are promptly addressed when they occur. Additionally, the upgrade includes enhancements and fixes to the core product that support the resiliency of electric delivery, ensuring that customers are receiving the energy they need when they need it. Also, the distribution system depends on availability of the HVD system, staying current with the solution provider upgrades is critical to the resiliency of both systems. The scope of this project is an upgrade to the HVD SCADA software and hardware, which encompasses the following: (1) upgrading the application software; (2) upgrading the underlying application hardware; (3) implementing new functionality for improved value to the Company; (4) making necessary configuration changes; and (5) updating documentation related to the integration changes. Alternative considered include: (1) Defer the biennial upgrade of the SCADA application and its hardware. The Company targets SCADA biennial application upgrades to stay within two versions of the current application state to maintain application stability and cyber security, given the critical nature of the SCADA system. This alternative was not chosen due to increased security risk and need for vendor support of the application. Additionally, the hardware is already past the end of its useful life and has been moved over to a 3rd party warranty provider. (2) Alternative Vendor solution. This option was not chosen because the move from our current vendor would be time consuming and costly. It could also introduce instability as any alternative solutions have not been proven operationally. (3) Do nothing. This option was not chosen due to the critical nature of these systems and the potential operational risks associated with operating on an unsupported solution. (4) The option chosen is to complete the upgrade project with associated hardware and software necessary to complete the project that will deliver new functionality for improved value.	2025-10-01	2026-12-04	-1.00	3,442,113	213,929		2,592,512	522,810	756,409	320,123	751,750	-	241,420	86,505	-	-	76,505	-	-	10,000
120	2026	Product Family Enhancements-Elect	Software(Intangible)	Electric	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software & hardware and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	920,161	183,276		920,161	-	837	478,931	214,339	-	226,054	183,276	-	-	53,032	130,244	-	-
121	2026	Product Family Enhancements-Elect	Software(Intangible)	Electric	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	259,106		-	-	-	-	-	-	-	259,106	-	-	223,279	35,827	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
122	2026	Service Restoration Artificial Intelligence	Software(Intangible)	Electric	Artificial Intelligence (AI) Machine Learning (ML) can enhance decision-making during restoration events by quickly evaluating multiple datasets, reduce non value-added time, and continuously improve through learning. This project will show the value of AI ML in Storm Declarations, Resource Planning, Resource Utilization/Crew Movements, and Asset Identification. The Company faces challenges in efficiently managing storm response and restoration efforts. Historically, storm declarations, resource planning, and crew movements have relied on manual processes and estimations, leading to delays and inefficiencies. The need for a more effective and timely response during restoration events has become increasingly critical, especially given the complexity and scale of modern storm events. This project creates value for the Company by (1) enhancing the storm response capabilities. This will enable faster and more consistent decision-making during restoration events, optimizing resource planning and crew movement and improving asset identification. (2) Delivering business value. The utilization of AI ML in service restoration processes is expected to reduce non-value-added time, improve public safety and create savings for customers. (3) Providing customer value. The AI ML applications will benefit customers by optimizing storm declarations, resource planning, crew movement and asset identification. These enhancements will lead to more efficient outcomes, faster restoration times and improved public safety. Furthermore, AI ML's learning abilities enable the decision-making to continuously improve, and those learnings have the durability to live beyond the human experience and mitigate learning curves as people transition from role to role. The project scope includes: (1) developing AI ML models for storm declarations, resource planning, resource utilization/crew movements, and asset identification. (2) Integrating with existing systems like Advanced Distribution Management System (ADMS), Customer Resource Manager (CRM) and Catastrophic Crewing in house built application. (3) Training and deploying. (4) Performance monitoring and (5) customer communication. Alternatives considered include: (1) continuing with the manual process. This option was not chosen because it results in underutilized crews, non-value-added time, and increased human error and difficulty. (2) Purchasing a storm work management solution. This option was not chosen due to its high cost, vendor dependency during the Company's most critical times, and complexity. (3) Creating an AI ML solution. This option was selected as it meets the criteria and will be scalable across service restoration and electric distribution.	2026-03-01	2027-05-30	-1.00	1,380,332	170,130	ROM	883,817	-	-	617,287	-	-	266,530	110,185	-	-	110,185	-	-	-	-
123	2026	Streetlight Outage and Restoration C	Software(Intangible)	Electric	This project will optimize the Streetlight Outage and Restoration (SOAR) application to better meet our customers need. The SOAR application is used by the Company's customers to report streetlight outages. This project will add new functionality to meet our customers' needs. While 68% of our customers are using SOAR to submit issues, between 15-20% of those issues are more than a lightbulb change/luminaire replacement, leading to multiple truck rolls, and work requiring long cycle scheduling. It lacks the most current source data due to manual process of updating the data, automation, and SMS text messaging, which leads to waste and customer dissatisfaction. By integrating these optimizations, Consumers Energy will streamline the work management system, reduce errors and provide a more comprehensive and efficient solution for our customers, our schedulers and our field workers. This project creates value for the Company by: (1) improving customer and municipality communications; (2) adding visualizations to improve accuracy and speed of repair; (3) adding field improvements such as getting the issue to the right department the first time and knowing what materials are needed so the light is fixed on the first visit; and (4) automating and updating the map which will allow for more accuracy. All of these will eliminate waste by using automation and properly mating of data. The project scope includes: (1) identifying correctly outages versus other work; (2) improving GIS data to include proper stock material and Temporary Traffic Control (TTC) requirements and prioritizing scheduled work based on outage repair needs; (3) offering SMS text messaging; (4) improving email communications by including more accurate details to customers; (5) daily automation of map data updating; (6) adding functionality for user-generated reliability reports; and (7) adding a new process to advise municipality of extended repair outages. The alternatives considered include: (1) continue the manual process. This includes adding municipality-named lighting layers to the Company's GIS solution, updating streetlight asset information and updating of the SOAR map. This option was not selected as it is heavy in human error and waste resulting in additional costs. (2) Purchase a new system. This option was not selected as it would be extremely expensive to purchase and wouldn't have all of the requirements needed. (3) Implement technology improvements. This alternative was selected because it will improve customer communications, improve accuracy and speed of repair.	2025-09-08	2026-10-29	-0.99	1,860,161	448,127		1,207,359	3,000	-	573,089	467,054	-	164,216	110,008	-	-	110,008	-	-	-	-
124	2026	Transmission Outage Application (Tr	Software(Intangible)	Electric	This project will modernize and streamline the high voltage system outage process, substation asset management, construction management and maintenance processes, as well as the high voltage project management process by replacing obsolete systems with an industry standard alternative and providing future integration opportunities with corporate systems. The current software version is no longer supported by the vendor and does not allow for the enhancements that would increase the functionality of the software. Also, the solution is susceptible to human error and duplication of efforts due to the manual nature of the work. Lastly, the ongoing support of the software is also costly and time consuming due to the outdated version and the requirements for the existing solution. The project will add value by: (1) simplifying the process of managing and rescheduling large HVD projects; (2) enhancing the ability to quickly identify conflicts created by schedule changes; (3) allowing the Company to internally support future integrations with existing applications; (4) improving resource management and visibility by planning Substation Construction, Substation Operations, and High Voltage Distribution (HVD) Lines resources by project; (5) implementing ability to plan Control Center resources based on planned work and control center capacity; (6) improving stability and repeatable reporting for defects and problem solving; (7) simplifying communication with stakeholder groups including Low Voltage Distribution (LVD) Scheduling, Business Customer Solutions, Electric Field Lab, and Substation Operations for outage requests requiring resource coordination; and (8) including 24x7 application support and patching due to using a Cloud solution. The scope of the project includes: (1) upgrading to the newest version of software for a real-time electric operations application; (2) migration of applications and data to cloud servers; and (3) end-user testing. The alternatives considered for the project include: (1) continuing with the current system and processes. This alternative was not selected because the current version is out of support, is prone to human error and duplication, and is costly to maintain. (2) breaking the project into separate Company built applications. This alternative was not selected because these individual applications would have integration complications and support issues, as they would all be separate entities. (3) purchase an off-the-shelf cloud option. This alternative was selected as it would not have customization of the base product or integration issues and comes with 24x7 cloud support.	2025-09-08	2026-07-31	-0.93	861,864	276,556		512,813	-	-	51,580	444,000	-	17,233	263,676	-	-	242,735	20,941	-	-	
125	2026	20% ROM Adjustment - Electric	Software(Intangible)	Electric	This is for the 20% ROM Adjustment for IT projects.							(324,457)	(1,119)	(218,598)	(106,070)	(98,686)	-	(107,430)							
126	**SUBTOTAL**	**2026 Electric**										**11,976,682**	**541,403**	**1,956,214**	**4,199,188**	**3,153,433**	-	**2,147,444**	**2,267,051**	**80,145**	**78,000**	**1,430,007**	**470,395**	-	**16,504**
127	2026	Application Currency-Electric & Gas	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	65,210	309,420		43,195	-	-	30,123	-	-	13,072	194,935	15,978	-	4,725	173,901	-	331	
128	2026	Application Currency-Electric & Gas	Software(Intangible)	Electric & Gas Shared	The Electric and Gas Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	663,259		-	-	-	-	-	-	-	417,853	-	-	377,460	40,393	-	-	
129	2026	Application Currency-Operational Te	Software(Intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	253,895		-	-	-	-	-	-	-	159,954	-	-	159,954	-	-	-	
130	2026	Customer Consecutive Estimate Red	Software(Intangible)	Electric & Gas Shared	The project will resolve gas and electric accounts with consecutive estimates due to the service being disconnected and customer's usage being estimated. Consumers Energy experienced two show cause orders from MPSC for consecutive estimates and fines of $500,000 in 2016 and $1M in 2023 including $3M that is to be refunded to the customers from the money that is recovered from the vendor. If the funding is not recovered from the vendor, the total fine would result in $4M as the Company is responsible for the difference between the dollars recovered from the vendor and the $3M total established by MPSC. The project objective is to reduce disconnected consecutive estimate accounts from 8% to less than 1% reducing non-compliance regulatory risk with MPSC rules. The project scope includes enhancing account and work management digital solutions to properly reflect disconnected account status. Process improvements were put into place after the 2016 show cause; however, increased electric meter failures, supply chain shortages, and a project focused on replacing meter technology due to the sunset of 3G communication led to issues that resulted in a second show cause order. Do nothing does not improve the customer experience. Our current solution of SAP CRM used by Call Center, SAP Work Management, ADMS for Storm and Service Suite for Field Work are all core platforms able to accomodate the change. Adding additional software or alternatives will complicate the technical solution and/or require additional training for Call Center & field personnel.	2025-04-01	2026-03-31	0.00	711,907	96,300		425,063	-	-	159,332	226,353	-	39,378	39,237	-	-	39,237	-	-	-	
131	2026	Product Family Enhancements-Elect	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric and Gas operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	1,036,665	155,294		686,687	-	6,824	131,640	476,047	-	72,376	97,835	-	2,946	16,775	78,114	-	-	
132	2026	Product Family Enhancements-Elect	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	215,871		-	-	-	-	-	-	-	135,998	-	1,410	105,880	28,708	-	-	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST-BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
133	2026	Spatial Asset Management	Software(Intangible)	Electric & Gas Shared	This initiative will implement SAPs Spatial Asset Management module. It will allow users to view assets, notifications, and orders geospatially using a map. The module will allow the Company to create and maintain asset maintenance plans for each segment of our gas and electric distribution networks (linear assets). The Company will create linear assets as technical objects (such as functional locations and equipment) and store linear data. The Company will enable creation of maintenance plans for these technical objects which result in notifications, maintenance orders, and measurement documents. We will enable monitoring the condition of our linear assets, identify where there is damage or a defect (using the start point and end point and offset), and manage all types of maintenance tasks (planned, unplanned, and preventative). Currently, the Company lacks spatial visualization and spatial awareness of work and assets impacting requirements for first time quality and impacting the ability to plan, bundle and execute nearby work. The lack of a linear asset management capability affects the full work management value stream resulting in overproduction of asset maintenance activity such as assessments, surveys, and inspections. This project creates value for the Company by (1) providing capability in SAP to view assets, notifications, and work orders on a map; (2) providing location awareness in SAP for assets and work; (3) establishing linear asset management capability in SAP for gas and electric delivery networks; and (4) enabling end-to-end map-based workflows. The scope of this project encompasses implementation in SAP of the Spatial Asset Management module. Alternatives considered include: (1) Implement a cloud-based individualized asset integration between GIS and SAP. This alternative was not selected as it proves ineffective in addressing needs of the end-to-end work management value stream while increasing the technical footprint of customization. There are also performance concerns with cloud to on-prem integrations; (2) Implement work group centric approaches to viewing work on a map. This alternative was not selected as it does not support standard operation through the entire work management value stream; (3) Do nothing. This alternative was not selected as this would result in increasing costs and inefficiencies in gas and electric work management; and (4) The alternative to implement the Spatial Asset Management module in SAP was chosen as it expands use of a core technology investment, supports current investment in our work management value stream, and is compatible with our GIS technology.	2024-05-10	2026-09-26	-1.00	2,981,655	97,619	ROM	236,450	-	-	79,223	119,232	-	37,995	33,705	-	-	14,605	18,900	-	-
134	2026	20% ROM Adjustment - Electric & Gs	Software(Intangible)	Electric & Gas Shared	This is for the 20% ROM Adjustment for IT projects.							(47,290)	-		(15,844)	(23,846)	-								
135	SUBTOTAL	2026 Electric & Gas Shared										1,391,395	-	6,624	459,217	521,832	-	162,521	1,879,517	15,978	4,357	716,535	348,016	-	331
136	2026	ARP-Radio	Network	IT/Digital Foundation	This project will refresh hardware to include: 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices, vehicle consoles in service trucks, other communications equipment, and associated test equipment. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 10-year lifecycle basis. Cellular modems are refreshed on a five-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle. 800Mhz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customers service and critical infrastructure. Company radio and cellular systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing or becoming obsolete. The refresh of this equipment in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety. This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure. The project scope consists of: (1) scheduled replacement of radios, modems, consoles; and (2) installing additional radios, modems, and console assets to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters and systems. The alternatives considered include: (1) Replacing the existing units with new units from other radio and modem manufacturers; (2) Purchasing new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.	2026-01-01	2026-12-31	-1.00	1,457,038	96,993		763,197	-	712,056	20,271	19,946	-	10,923	61,105	-	55,976	3,534	1,260	-	336
137	2026	ARP-Collaboration	New Computers / Hardware	IT/Digital Foundation	This project will replace the Company's obsolete or out-of date audio, visual, telephony and other communication collaborative tools and equipment. When collaboration assets used to support customer interactions and business operations are obsolete or out-of-date, they are more difficult to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project creates value by: (1) ensuring the stability and reliability of the Company's audio, visual, telephony, and other communications systems; and (2) migrating to new collaboration assets. The project scope consists of: (1) replacing aging collaboration assets; and (2) installing new collaboration assets to meet evolving business requirements. The alternatives considered include: (1) continuing to operate collaboration assets beyond a five-year refresh cycle, or (2) refreshing collaboration assets based on a five-year refresh cycle while evaluating the health of the asset and evolving business requirements. The alternative to operate the collaboration assets beyond a five-year refresh cycle was not selected due to the risk of asset failures would cause stability and reliability issues for employees supporting our customers, as vendors do not provide extended support after five years. The Company chose to refresh the collaboration assets based on a five-year refresh cycle and evaluate the health of the asset and evolving business requirements to reduce the risk of impacting the productivity of employees supporting our customers.	2026-01-01	2026-12-31	-1.00	1,162,872	180,585		770,287	-	694,358	22,925	45,627	-	7,377	113,756	-	21,704	25,902	66,150	-	-
138	2026	ARP-Field Device Asset Managemen	New Computers / Hardware	IT/Digital Foundation	This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility. When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices before they fail; and (2) allowing field workers to complete their job tasks. The project scope consists of replacing field device assets according to the four-year refresh cycle. toAlternatives considered include: (1) using outdated equipment. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact meter readers' ability to complete job tasks. It would also complicate the Company's efforts to meet the MPSC's meter reading factor and consecutive estimated targets, and it could cause applications to run poorly or stop functioning; (2) The second alternative considered was to replace the hardware. The Company selected this option to alleviate the above concerns.	2026-01-01	2026-12-31	-1.00	7,579,082	5,000		5,020,370	-	4,690,086	94,833	-	-	35,452	3,150	-	3,150	-	-	-	-
139	2026	ARP-Operational Technology Suppo	New Computers / Hardware	IT/Digital Foundation	The Asset Refresh Program (ARP)-Operational Technology (OT) Support Common project will replace dated and obsolete servers shared by Electric and Gas on a rotating five-year refresh schedule. When Operational Technology Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure. The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure.	2026-01-01	2026-12-31	-1.00	1,655,506	152,731		1,096,607	-	993,600	28,918	-	-	74,089	96,221	-	90,720	5,501	-	-	-
140	2026	ARP-Operational Technology Suppo	New Computers / Hardware	IT/Digital Foundation	The Asset Refresh Program (ARP)-Operational Technology (OT) Support Electric project will replace dated and obsolete servers on a rotating 5 year refresh schedule. When Operational Technology Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure. The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five to seven-year refresh cycle or (2) refresh hardware based on a five to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five to seven-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety for customers, as vendors do not provide extended support after seven years. The Company chose the alternative to refresh this hardware based on a five to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Electric SCADA.	2026-01-01	2026-12-31	-1.00	190,856	17,183		190,856	-	165,000	10,914	-	-	14,942	17,183	-	15,000	2,183	-	-	-
141	2026	ARP-Printer Asset Management (PAI	New Computers / Hardware	IT/Digital Foundation	This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one. When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications. The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. This does not mean that all printers are replaced after five years merely that printers are assessed on a five-year cycle for possible replacement. The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years would require the printers to be assessed monthly to ensure they are not run to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.	2026-01-01	2026-12-31	-1.00	184,794	5,000		122,408	-	119,194	2,339	-	-	874	3,150	-	3,150	-	-	-	-
142	2026	ARP-Workstation Asset Management	New Computers / Hardware	IT/Digital Foundation	This project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates. When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks. The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP in future years based on the number of devices that were not replaced during the four-year refresh cycle ; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets; and an eight-year cycle for monitors to alleviate these concerns.	2026-01-01	2026-12-31	-1.00	5,542,158	51,618		3,671,126	-	3,486,135	83,027	72,831	-	29,132	32,519	-	30,575	1,945	-	-	-
143	2026	Digital-Hybrid Cloud and Data Cente	New Computers / Hardware	IT/Digital Foundation	This project will optimize data center assets and asset replacement project purchases by migrating or retiring applications out of existing Company and co-location data centers into cloud services, reducing operational costs for running IT services and leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services. The technology currently deployed in the Company's data centers meets many customers' needs today. However, the pace of digital transformation is increasing rapidly, and requirements for applications are evolving faster than the technology in the Company's data centers can respond in a cost-effective manner. These data center constraints lead to longer implementation times, missing capabilities, or reduced functionality in the applications that the Company can deploy. This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective combination of data centers and public cloud services. Specifically, by migrating applications to cloud services, the project will: (1) reduce capacity, hardware maintenance, and security device costs at the co-location data center; (2) reduce hardware maintenance and security device costs at the production data center; (3) enable the ability to scale infrastructure quickly up or down without costly up-front hardware purchases; (4) reduce application risk through cost-effective, scalable infrastructure redundancy and availability; (5) reduce ongoing server and storage asset replacement costs; (6) reduce ongoing networking equipment replacement costs; (7) reduce operational support costs; and (8) enable the use of a vast array of cloud services to support Company applications. The project scope includes: (1) promoting the robust main co-location data center to become the primary data center for on-premise IT services; (2) demoting the Company's production data center to the disaster recovery data center for on-premise IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premise to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying base infrastructure to allow each location (on-premise or in cloud) to function independently; (7) deploying cloud and on-premise cost management tooling and processes; (8) simplifying and optimizing backup and disaster recovery resources and processes using cloud services; (9) implementing additional automation for application deployment and management; (10) changing the operations model for support of cloud-based applications; (11) educating and increasing the skills of IT and other employees in leveraging public cloud services; and (12) transforming IT to become the broker of cloud services for the Company. Alternatives considered include: (1) migrating to public cloud services faster. This alternative was not chosen because the Company's ability to absorb new technologies coupled with the investments the Company has already made in data center equipment would prevent a faster move from being efficient and effective, introducing additional financial risk; (2) migrating to public cloud services slower or not at all. This alternative was not selected because delaying public cloud services and capabilities coupled with requiring an extension of the life of existing data center equipment creates increased financial and operational risk; and (3) contracting with an outside vendor to provide cloud services to run applications for the Company. This alternative was not selected because industry information shows the option as not yet cost-effective or not providing a maturity level that the Company would be able to easily consume with limited in-house experience and expertise in public cloud. The alternative to migrate to a hybrid cloud and data center model was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.	2023-04-02	2026-12-31	0.17	10,913,922	2,440,581		1,148,137	-	-	242,564	852,940	-	52,633	173,047	-	-	20,794	152,253	-	-
144	2026	Operational Technology (OT) Datace	New Computers / Hardware	IT/Digital Foundation	The OT environment consists of systems supporting the control and monitoring of electric grid, electric generation, gas compression, and natural gas pipeline. These systems are critical for safe and reliable natural gas and electric delivery. The OT Datacenter Migration project enhances the Company's capabilities by co-locating to an enhanced datacenter at a vendor facility. The Company's current datacenter for the OT environment needs modernization and relocation from the Parnall Data Center. The current location is not the preferred location to house servers and systems critical to the control of the Electric Grid or Gas Pipeline due to the close proximity to a railway system. The climate conditioners in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns . The location of the datacenter in the basement of the Parnall building is nearby to the main water piping for the building. There have been instances of water infiltration in the past. This project creates value for the Company by significantly strengthening capabilities through: (1) mitigating legacy physical and location risks at the current Parnall site; (2) migrating the OT infrastructure to a modern, highly secured environment with redundancy in climate conditions; and (3) better datacenter facilities support with a guaranties of redundant power. The scope of the project includes: (1) migration of the OT environment from the Parnall Data Center to a co-located vendor data center; (2) re-validation of the OT Production and Disaster Recovery procedures once migration is completed; (3) migration of IT systems required for supporting the OT environment; and (4) decommission the existing OT environment from the Parnall location. The Company performed an analysis of alternatives to expand capabilities as well as address constraints and risks: (1) Remain at the current Parnall Data Center; (2) migrate OT environments to the Cloud; and (3) relocate to a third-party co-location facility. Current industry best practices do not recommend migration of OT environments to the cloud. The co-location vendor provides the building, cooling, power, and physical security the Company lacks for its servers, storage, and other computing and networking equipment at the current Parnall location. Based on the analysis, the Company decided to implement the third alternative.	2026-06-30	2027-12-11	-1.00	7,749,620	1,856,450	ROM	2,908,884	211,487	2,119,098	150,579	211,487	-	216,233	569,615	-	-	226,265	343,350	-	-

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Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
145	2026	Security/OT Field Modernization	New Computers / Hardware	IT/Digital Foundation	This project will implement new infrastructure for accomplishing improved security in the field for OT assets. Gas and Electric technicians are using corporate laptops, to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. Vendors and contractors have access to the Company's critical infrastructure using non-Company laptops. Best practice is to use dedicated laptops to connect to critical infrastructure. The value of this project is deploying dedicated Company OT laptops and associated OT infrastructure that can move between OT locations only and providing a secure environment. This project will procure and configure approximately 130 devices that will be used to manage critical OT infrastructure. The Company reviewed several options to mitigate cyber security risks inherent with the use of standard corporate laptops managing critical infrastructure. The alternatives considered are: (1) Continue utilizing existing workflow of using Corporate domain laptops with software installed; (2) Bring in an outside vendor to design and implement a proposed infrastructure; (3) Complete disallowance of all local access to critical systems; (4) Extending the OT network to remote Company locations; (5) Deploy a dedicated Company OT laptop and OT communications circuits, which includes cellular connectivity. The dedicated OT laptop and communications circuits presented the best way to secure the critical infrastructure by limiting internet and e-mail access. Vendors and contractors could also utilize these approved dedicated systems for managing infrastructure they help support at Company locations. Based on the analysis performed, the Company chooses to deploy a dedicated OT laptop and communications circuits which is not a cloud related solution, since it is hardware and not software.	2025-02-20	2026-12-30	-1.00	2,117,568	310,431		624,390	80,596	-	252,587	232,203	-	59,005	155,620	98,611	-	20,020	33,541	-	1,447
146	2026	20% ROM Adjustment - IT/Digital Fo	New Computers / Hardware	IT/Digital Foundation	This is for the 20% ROM Adjustment for IT projects.							(581,777)	(42,298)	(423,619)	(30,116)	(42,298)	-	(43,247)	-	-	-	-	-	-	-
147	2026	Application Currency-IT/Digital Foun	Software(Intangible)	IT/Digital Foundation	The Application Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms area are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	472,347		-	-	-	-	-	-	-	297,579	-	-	297,579	-	-	-
148	2026	Application Currency-IT/Digital Foun	Software(Intangible)	IT/Digital Foundation	The Infrastructure Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Infrastructure Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Infrastructure Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	109,556		-	-	-	-	-	-	-	69,020	-	-	33,676	35,344	-	-
149	2026	BizTalk Services Migration and Retir	Software(Intangible)	IT/Digital Foundation	The Microsoft BizTalk application transfers data from one location to another with internal and external software systems and assists with securely communicating sensitive financial data. The project will migrate the BizTalk application services to other existing applications resulting in the retirement of the Biztalk application. Microsoft announcing end of life for this application a replacement is needed to avoid business impact. The current version of Biztalk running at Consumers Energy is already out of mainstream support. If major issues occur within the application, it could disrupt critical business processes. This includes financial concerns such as payroll, account receivable, and other essential operations. Ensuring continuity is vital. This project creates and maintains value for the Company and its customers by migrating the Biztalk services to supported applications already present in the Consumers Energy environment that do have not end of life concerns and can provide the same functionality Biztalk was providing to meet business requirements. This project creates and maintains value for the Company and its customers by: (1) Migrating all current processes from the current application to replacement products. The secure file transport processes will be migrating to the existing Axway Secure Transport platform. The Electronic Data Interchange processes will be migrated to the existing SAP platform. (2) Ensuring current and future compliance with Information Security critical and sensitive data initiatives, such as patching, data encryption, and authentication requirements. (3) Guarantees 7x24x365 vendor support is available to the Company during significant outages by remaining on a version supported by the vendor. Alternatives considered included: (1) Using Azure native services to recreate all of the processes and services Biztalk provided. This was cost prohibitive due to time and effort this would take. (2) Purchasing a replacement product. Not new or optimal as existing applications are already implemented within Consumers Energy that provide the same capability. (3) Leverage existing applications within the Consumers Energy application portfolio. This option was selected as lowest cost option and also to meet application rationalization goals to eliminate applications that are providing duplicate functionality.	2025-02-28	2026-10-31	-1.00	876,410	930,309		580,534	-	8	177,055	358,935	-	44,536	245,395	-	-	104,307	141,088	-	-
150	2026	Business Capability Mapping SaaS T	Software(Intangible)	IT/Digital Foundation	The Business Capability Mapping (BCM) SaaS Tool is a cloud based software solution which will visualize the Company's capabilities related to our metrics, data maturity, supporting technologies, financial allocations, and other view points. The tool will automate analysis and report generation to quickly provide information while supporting other efforts directly supporting technology investment planning and management. The current lack of a centralized tool for tracking enterprise-wide data, which is manually managed via Excel, poses significant challenges. This manual process limits data sharing and the distribution of business capability roadmaps, complicating investment planning and alignment. The absence of a centralized tool also hinders effective communication regarding prioritization and application stack updates, preventing a comprehensive view of impacted areas. Consequently, the enterprise architecture practice struggles to accurately plan and forecast investment opportunities, leading to misallocation of funds, labor, and potential delays in enabling strategic opportunities. The solution will include implementing a centralized tool to streamline data sharing, enhance communication, and support accurate planning and forecasting. The company will see value through: (1) Implementing processes and supporting technical components to enable automated scoring of capabilities, including scores, measures, metrics, KPIs, and OKRs for consistent and accurate analysis; (2) Developing a consolidated view of critical capabilities, applications, and infrastructure, ranked based on their efficiency and effectiveness in meeting company objectives; (3) Integrating key technology features supporting Application Rationalization, Enterprise Resource Planning (ERP) system and major platform upgrades, Business Capability Modeling, Application Stack Ownership, Enterprise Architecture Artifact Tool Repository, centralized repository and role based access; (4) Generate a consistent framework to support the prioritization of investments based on their impact on key capabilities across the enterprise, (5) Implement a shared platform to integrate architecture activities versus siloed practices; and (6) Consolidate empirical data used for investments and technical health to ensure accuracy and consistency in evaluations. The project scope includes: (1) Implement a role-based access SaaS product and Integrate with ServiceNow and other internal systems; (2) Configure the SaaS product with identified tools for data gathering on capabilities and their performance; (3) Develop processes and automation to gather data on capabilities, including applications, technical infrastructure, and metrics; (4) Establish a framework for prioritizing investments; (5) Create role-based dashboards and reports to visualize the output of data analysis; (6) Develop automated communications for key business decisions, investment plans, data collection, and reports; (7) Enable self-reporting on data within the tool; (8) Connect supporting documentation to the capabilities; and (9) Provide training on how to use the tool including end-user training. Alternatives considered for this include: (1) Continue with current practices for initiative planning and Enterprise Architecture practices. This was not selected as it does not address gaps in enterprise-wide practices and consolidated roadmap capabilities addressing key company objectives. (2) Develop in-house applications using multiple platforms including Excel, PowerBI, and custom development. This was not selected due to complexity of the solution and cost of delivery. Additionally, the dependency on the automated processes would create additional hurdles for efficient delivery. (3) Acquire external tools to support BCM, Enterprise Architecture, and investment planning. This solution was selected as it provides quick and efficient access to automated tools within acceptable cost ranges.	2026-03-25	2026-06-25	-0.52	548,250	171,200	ROM	363,161	-	-	248,400	-	-	114,761	107,856	-	-	85,806	22,050	-	-
151	2026	Data & Analytics Platform Rationaliza	Software(Intangible)	IT/Digital Foundation	This project will optimize the Data & Analytics system landscape by creating connections, migrating data into the Data Lake in the cloud, and building visualizations from the data in the Data Lake. The IT Data & Analytics legacy systems (SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BCDS) are outdated, inefficient, and becoming duplicative in nature with the introduction of DL 2.0. If these legacy systems are not retired, they will continue to cost the Company money as major investments are needed to maintain and support them. This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources. The project scope includes: (1) the assessment of the existing Data & Analytics platforms including SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BCDS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organization change management; and (7) the retirement/decommissioning of the legacy platforms and applications. Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company's cloud strategy. (2) Lift and shift these on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces. (3) Migrate all data sources to DL 2.0 and retire legacy systems. This alternative was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.	2025-04-07	2027-12-31	0.24	9,019,671	1,319,807		2,652,770	280,195	-	879,438	1,263,049	-	230,087	439,789	406,339	-	22,274	11,176	-	-
152	2026	Enterprise Service Bus 2026-2027 U	Software(Intangible)	IT/Digital Foundation	This project will upgrade the current Enterprise Service Bus software versions in use at the company. This will also implement a container management system and migrate various services to containers. Newer ESB software versions offer improved integration with RestAPI services and applications. It is critical that this vital data tool or pathway, be more scalable, secure, and capable of integrating to a service-based environment. The lack of a container management solution prohibits the adoption of a more cloud native approach leading to retaining legacy solutions. The value this project provides the Company includes: (1) implement a container management solution; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies. The project scope includes (1) implementing the current version of all applications that are part of the ESB application, database version, and required database drivers and (2) implementing a Kubernetes solution for container management and migrate targeted services that are identified as microservices to containers. Alternatives considered included: (1) Accept the current version levels and continue to pay for extended support costs and accept technical obsolescence risk. (2) Only upgrade the existing applications. (3) Upgrade all of the applications as well as evolve the cloud-based instance to a more cloud native architecture by converting containers and implementing a Kubernetes solution to manage the containers. This option was selected because it best meets the Company needs for the near future by maintaining vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.	2026-09-01	2027-11-22	-1.00	1,331,120	1,042,944	ROM	-	-	-	-	-	-	-	19,809	-	-	19,809	-	-	-
153	2026	HR Support Pack and Business Soft	Software(Intangible)	IT/Digital Foundation	The Human Resources (HR) Support Pack and Business Software Inc (BSI) upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll. This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company. oAlternatives considered include: (1) not upgrading to the current support packs, which results in noncompliance with financial rules and regulations and inaccurate payroll. (2) there is no economical cloud solution, so this option was not entertained. (3) the Company decided the best alternative is to apply the appropriate support pack upgrades. This option is preferred because it enables the Company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.	2026-01-23	2027-02-15	0.00	-	665,132		-	-	-	-	-	-	-	419,033	-	-	63,727	355,306	-	-
154	2026	ISIS Papyrus 2026 Upgrade	Software(Intangible)	IT/Digital Foundation	This project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The ISIS Papyrus application is critical to creating electronic and paper correspondence for customers, including bills and dunnings. The application will be at least one major upgrade revision behind by 2026. It's imperative that customers retain unfettered access to their paper bills, dunning notices and other communications produced by ISIS. ISIS also makes customer bills available for online viewing through the website and mobile apps. Without the upgrade, vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity and security will be forthcoming. The upgrade will address these problems and challenges, as well as ensuring all other platform components comply with the Company's operational and security standards. The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors. The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications. Alternatives considered include: (1) delaying the upgrade and continuing to operate with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching. (2) The Company instead decided to upgrade to the current version. This alternative was chosen as it eliminates the risk of application instability and the inability to maintain cyber security patching.	2026-02-01	2026-10-01	-1.00	-	217,246	ROM	-	-	-	-	-	-	-	136,865	-	-	136,865	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
155	2026	Kubra 4.0 Upgrade	Software(Intangible)	IT/Digital Foundation	Consumers Energy (CE) has the overarching ambition of serving 1 in 3 Low-to-Moderate Income (LMI) customers (currently 1 in 6), while supporting the achievement of clean energy goals and reduction in Uncollectible Expense (UCX). 37% of CE customers are low to moderate income (LMI). Low Income (LI) accounts for 11% and means they are currently in crisis and unable to pay their bill. Moderate Income (MI) accounts for 26% and means they are one financial crisis away from being unable to pay their bill. As part of the LMI effort, we are prioritizing Behavior Based Direct Messaging: Meet the customer where they are, communicate about assistance options based on behavioral indicators, and increase the likelihood of enrollment into meaningful assistance programs ahead of a crisis, and Kubra 4.0 will aid in the success of those LMI goals. To help a customer avoid a crisis before it happens, we need the ability to proactively communicate to them when their behaviors signal the possibility of an issue, some examples being: (1) A customer misses a payment after record of making payments for several months, (2) The auto-pay system receives an insufficient funds alert from the customers' account, (3) Energy use is high, and a bill is projected to be 25-50% larger than usual, and (4) Localized / seasonal triggers such as heat waves, blizzards, and ice storms. Additionally, (5) it's imperative that we're able to text and modify message content that captures the customer's attention, so that we may drive awareness to programs that offer assistance ahead of a crisis. Kubra 4.0 platform is more flexible and configurable to help experimental design & marketing iterate on who/where/what to cut through digital noise. This project creates value for the Company through improving customer communications by providing Consumers Energy (CE) with access to (1) templates and wording changes that previously required expensive Statement of Work (SOW) engagement to deliver and (2) reduce lengthy wait times to implement these aforementioned Statements of Work (SOWs). Finally, (3) this engagement will also introduce 12 net new alert messages, (4) allow for new means of communication and messaging via the mobile app push notification feature, and (5) provide better outage notification reliability and control via Application Programming Interface (API) data transfer instead of Secure File Transfer Protocol (SFTP) data transfer. The project scope includes: (1) 12 net new alerts including 4 for the Shut-off Protection Plan (SPP), missed payment(s), summer event alerting, winter event alerting, and 5 additional alerts to be detailed out during the plan & design phase of the effort based on current low-to-moderate income (LMI) customer communication needs, (2) new template editor as part of the upgraded platform, (3) New Push Notification option available for mobile app which will enable a fast follow enhancement to push notifications through more than just email and text, (4) all other updates and improvements through Kubra 4.0 including use of APIs and other technical improvements, and (5) a new Application Programming Interface (API) built specifically for CE's outage messages for better reliability - instead of the existing file transfer outage information which is less reliable. The alternatives considered include: (1) continue the expensive Statements of Work (SOW) approach for updating each message template and for bringing on any new messages. This would total approximately ~50k per new alert, for a total of 600k for all 12 net new alerts for this effort if pursued individually. This total is not including costs to any existing message adjustments. This alternative was not considered due to the extra cost and overhead. (2) Purchase a new customer communications system. This option was not selected as it would be extremely expensive to purchase and wouldn't have all of the requirements needed and would be a tremendous amount of labor to reintegrate with our existing communication channels. (3) Utilizing Microsoft Dynamics or Riverstar. This option was not selected as it would be a tremendous amount of labor to reintegrate with our existing communication channels nor would either of the platforms fully support the bandwidth or channels needed to properly communicate out what we send via Kubra today. (4) Implement the upgrade to include the new alerts. This alternative was selected because it will improve customer communications, improve accuracy and speed of message updates, and offer more message options to achieve the Low-to-Moderate income (LMI) 1-in-3 goal as we're able to keep expanding our communication options with the upgrade's features.																								
156	2026	MS Self-hosted Gateway Solution ar	Software(Intangible)	IT/Digital Foundation	This project is looking to retire the API Exchange Gateway used primarily by the Enterprise Service Bus and replace it with a new solution called Microsoft Self-Hosted Gateway in security Zone B. The API Exchange Gateway is used by the TIBCO ESB to integrate corporate applications. New development will need to be done to integrate this solution. The Tibco API Exchange Gateway is anticipated to be sunset by the vendor, as they have already dropped all development of enhancements for the platform. The end of life date is 6/30/25 This project creates value for the Company by: (1) Avoiding the risk of running a project no longer supported by the vendor (i.e. the Tibco API Exchange Gateway Exchange module), and (2) Enabling the Company the opportunity to move to a product that is more stable, secure, and usable. The project scope includes: (1) Implement the Self Hosted Gateway into Zone B as a replacement solution. (2) Migrate all current work items to the new platform or existing equivalent based on use case. (3) Conduct appropriate testing to ensure all Service Level Agreements are met. Alternatives considered include: (1) Evaluating the replacement of the current product with a new product that is not already in the Company environment. This alternative was not selected because it would not be cost effective. (2) Keeping the current application as-is. This alternative was not selected as the vendor for the current platform has stopped all development for this product and the EOL has been set (3) Leveraging an existing solution already in the Company environment. This alternative was not selected as an existing product in the corporate Zone B layer does not exist. (4) Implement the Microsoft Self-Hosted Gateway and migrate current data into new platform. This alternative was selected as the most cost-effective solution that has ongoing support from the publisher.	2026-01-23	2026-10-30	-1.00	-	289,131	ROM	-	-	-	-	-	-	-	182,152	-	-	139,399	42,754	-	-
157	2026	Product Family Enhancements-Appli	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	940,471	188,000		622,968	-	-	435,101	-	-	187,867	118,440	-	-	118,440	-	-	-
158	2026	Product Family Enhancements-Appli	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	169,780		-	-	-	-	-	-	-	106,961	-	-	106,961	-	-	-
159	2026	Product Family Enhancements-Infras	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software & hardware and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	589,117	201,062		390,231	-	-	272,550	-	-	117,681	126,669	-	-	126,669	-	-	-
160	2026	Product Family Enhancements-Infras	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	46,664		-	-	-	-	-	-	-	29,398	-	-	29,398	-	-	-
161	2026	SAP Support Pack Upgrade 2026	Software(Intangible)	IT/Digital Foundation	The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for business partners. To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability. The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility. The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component (ECC), Customer Relationship Manager (CRM), Enterprise Portal, Process Orchestration (PO), Business Warehouse (BW), Business Objects (BOBJ), Data Services (DS), Solution Manager, Data Quality Manager (DQM), Graphical User Interface (GUI), Single Sign On (SSO), System Landscape Directory (SLD) and other related SAP applications. Alternatives considered include: (1) dividing the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) migrating to SAP S/4HANA. This option was not selected because SAP S/4HANA is a multi-year project that is not expected to be completed by year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3) Ultimately, the Company chose to balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.	2026-02-02	2026-10-31	-1.00	-	454,370		-	-	-	-	-	-	-	286,253	-	-	58,856	227,398	-	-
162	2026	20% ROM Adjustment - IT/Digital Fo	Software(Intangible)	IT/Digital Foundation	This is for the 20% ROM Adjustment for IT projects.							(72,632)	-	-	(49,680)	-	-	(22,952)	-	-	-	-	-	-	-
163	**SUBTOTAL**	**2026 IT/Digital Foundation**										**20,349,017**	**529,980**	**12,755,716**	**2,894,698**	**3,014,721**	**-**	**1,153,901**	**3,810,596**	**504,950**	**220,274**	**1,649,911**	**1,433,668**	**-**	**1,783**
164	2026	ARP-Cyber-Common	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions shared by Electric and Gas. When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades. The alternatives considered include: (1) upgrade or replace only the assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.	2026-01-01	2026-12-31	-1.00	1,719,036	18,809		900,431	-	835,985	42,167	2,300	-	19,980	11,850	-	3,150	8,131	-	-	569
165	2026	ARP-Cyber-Electric	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions for Electric.	2026-01-01	2026-12-31	-1.00	412,647	16,736		412,647	200	368,500	28,586	1,800	-	13,561	16,736	-	4,000	11,903	-	-	833

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST-BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
166	2026	ARP-Network-Common	Network	Security	This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks shared by Electric and Gas. When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks. The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices. The alternatives considered include: (1) continuing to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.	2026-01-01	2026-12-31	-1.00	833,668	14,560		436,676	4,190	400,808	15,714	8,016	-	7,947	9,173	-	3,760	5,040	-	-	353
167	2026	ARP-Network-Electric	Network	Security	This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks for Electric. When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks. The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices. The alternatives considered include: (1) continuing to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.	2026-01-01	2026-12-31	-1.00	66,368	1,056		66,368	200	58,305	4,500	1,166	-	2,197	1,056	-	200	800	-	-	56
168	2026	Critical Substation Upgrade	Network	Security	This project will implement enhanced security measures at the Company's critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time. With the enhanced security posture, Consumers Energy will be better positioned to mitigate malicious activity through real-time detection and increase the reliability of electric delivery to our customers. Today, Consumers Energy currently deems 16 substations as business critical to its electric system while an additional 34 substations fall under NERC-CIP compliance. Recent attacks to critical infrastructure have increased the likelihood of an adversary exploiting vulnerabilities at critical substation increasing the risk for large scale outages and customer impact. The Company's current security measures do not allow us to detect, deter, or monitor potential threats on site. Without the ability to monitor these assets in real-time, the Company is vulnerable to an adversary causing destruction without knowledge of when or how the event took place. A phased implementation would allow the Company to systematically mitigate risk to assets deemed most vulnerable. The objective of this project is to implement enhanced security measures to better detect, deter, and respond to threats to the Company's electric substations in real-time. This enhanced security posture will align with other utilities that own and operate substations and mitigate disruption to electric service while improving reliability. Enhanced Security measures that will need to be implemented include but are not limited to: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fence intrusion (which will be accomplished through camera systems); (6) subcontractor work of trenching poles, installing equipment etc., (7) additional facility lighting; and (8) security equipment maintenance. Alternatives considered include: (1) maintaining the current security perimeter fencing and conducting routine inspections of the site. This alternative was not selected, as it does not provide the ability to prevent, detect, or respond to threats in real-time; (2) hiring contract security guards to patrol the sites. This alternative was not selected as ongoing O&M costs would be expensive; (3) outfitting sites with thermal cameras with built in analytics that would alarm to intrusions and subjects on the properties along with access control measures. This alternative was selected because it had lower ongoing O&M costs and enhanced detection abilities.	2026-01-01	2026-12-31	-1.00	11,771,395	1,016,500	ROM	2,600,895	-	312,500	609,375	1,562,500	-	116,520	267,500	-	-	267,500	-	-	-
169	2026	20% ROM Adjustment - Security	Network	Security	This is for the 20% ROM Adjustment for IT projects.							(272,470)	-	(32,738)	(63,838)	(163,688)	-	(12,207)	-	-	-	-	-	-	-
170	2026	ARP-Physical Security	New Computers / Hardware	Security	The ARP-Physical Security, formerly known as Physical Security Asset Refresh, will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns. The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring alerts, compliance with regulations and guidelines, and faster responses to emergencies and incidents. This could result in an increase of potential security vulnerabilities, associated penalties, and reputational damage. The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reduce gaps in functionality; and (3) optimize overall system performance. Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) advanced analytics on security cameras for monitoring and real time alerting capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems. Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security assets not meeting the industry standard of 3-to 7 years for indoor cameras and 3 to 5 years for outdoor cameras. Alternatives 1 and 2 were not selected due to the risk of security concerns, utilizing equipment that is at end of life and no longer supported, and the risk of a lack of inability to meet regulatory requirements (FERC, NERC, TSA and NRC). The alternative selected maintains compliance, reduces redundancies and gaps in functionality, provides up to date support for the assets and current technological capabilities and optimizes overall performance of physical security systems.	2026-01-01	2026-12-31	-1.00	2,112,820	12,626		1,399,532	-	660,126	110,568	387,504	-	41,334	7,954	-	-	5,434	2,520	-	-
171	2026	Application Currency-Security-O&M	Software(Intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrade. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	403,127		-	-	-	-	-	-	253,970	3,366	-	250,604	-	-	-
172	2026	Enhancements-Security-Capital	Software(Intangible)	Security	This initiative will use Capital funding to make enhancements to existing technology and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements in accordance with accounting rules. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	816,175	152,674		540,634	258,914	17,440	107,150	90,845	-	66,285	96,185	2,914	-	70,887	22,384	-	-
173	2026	Enhancements-Security-O&M	Software(Intangible)	Security	This initiative will use O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	494,044		-	-	-	-	-	-	311,248	36,489	12,100	252,285	10,374	-	-
174	2026	Saviynt Enterprise Identity Governan	Software(Intangible)	Security	The project will implement Saviynt EIGA module, consolidate Identity Access Management (IAM) functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications. The current version of AccessNow reached end of life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and customizations. While beneficial for end users, these integrations increase the risk of system failures, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduces failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention. This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt EIGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) Minimizing custom code and focusing on configurations only by utilizing out of the box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface. This project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Streamlining processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access system; (4) Addressing issues with aging applications, multiple IAM platforms, integration challenges, and antiquated HR processing. Alternatives considered include: (1) Implementing trial fixes to AccessNow version 8.1.5 to ensure support through mid-2023; (2) Upgrading only the application to current-supported version, excluding the new web portal but will include new application functionality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any breakfix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating AccessNow software.	2024-07-01	2027-10-29	-1.00	6,052,582	577,224		843,707	-	33,120	158,877	397,440	-	254,270	38,019	-	-	38,019	-	-	-
175	**SUBTOTAL**	**2026 Security**										**6,926,420**	**263,505**	**2,854,047**	**1,913,099**	**2,287,853**	**-**	**509,586**	**1,913,691**	**42,769**	**23,230**	**910,603**	**35,276**	**-**	**1,811**
176	**TOTAL**	**2026**										**44,715,257**	**1,334,888**	**17,558,954**	**9,740,781**	**11,368,363**	**-**	**4,712,071**	**10,025,179**	**643,642**	**317,660**	**6,290,438**	**2,752,611**	**-**	**20,429**
177	2027	Application Currency-Corporate-O&M	Software(Intangible)	Corporate	The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2027-01-01	2027-12-31	-1.00	-	240,400		-	-	-	-	-	-	161,452	-	-	-	161,452	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST-BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
178	2027	Asset Accounting Tax Upgrade	Software(Intangible)	Corporate	The project will upgrade the Company's current on-premise accounting asset management tax software to the SaaS version as required by the vendor ensuring continued support of a critical financial application and providing new functionality. In 2025, standard vendor support ends for the current on-premise PowerTax software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the tax fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility. This project creates value for the Company by ensuring compliance with regulated and financial accounting within the tax fixed asset sub-ledger. In addition, the project adds value by: (1) moving to a SaaS solution in order stay supported; and (2) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) evaluating current vendor/product solutions with market leaders; and (2) upgrading the vendor software from the current version to the newer SaaS version; or replacing it. Alternatives considered include: (1) evaluating SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features such as centralized tax error processing. (2) evaluating other software options. This option may not provide appropriate regulatory reporting and other needed improvements and introduces several complexities and costs: Integration Challenges as PowerPlan modules are designed to work seamlessly together and data synch, mapping, and real-time updates may not be as robust as with native modules; Loss of Automation and Efficiency as there may be manual data transfers, duplicate entries and reduced automation increasing labor costs and risk of mistakes; Higher IT and Support Costs as maintaining two asset accounting systems means higher IT overhead with upgrades, troubleshooting, and user training; Reduced Data Integrity and Security as splitting tax data between systems can create gaps in data integrity, audit trails, and security controls; and Limited Vendor Accountability as when issues arise, vendors may point to integration boundaries making troubleshooting and issue resolution slower and more complicated. (3) moving entire PowerPlan suite, which includes PowerTax, to their cloud option. This option would be expensive from a licensing and integration build perspective, has an unclear timeline, and would remove the opportunity for direct database control. (4) waiting until a future upgrade cycle. This option introduces technical risk and potential financial processing risk. (5) upgrading to a newer version of the current solution. This is the preferred option as it will provide more frequent software upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.	2027-02-01	2028-02-28	-1.00	-	400,191	ROM	-	-	-	-	-	-	-	216,103	-	-	81,459	134,644	-	-
179	2027	Asset Accounting Upgrade 2027-202	Software(Intangible)	Corporate	The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application. Standard vendor support will be ending for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complex testing activities and too many version increases at any one time. This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted. The project scope includes: (1) evaluating current vendor/product solution with market leaders; and (2) upgrading the vendor software from the current version to a newer version. Alternatives considered include: (1) Evaluated SAP options for leasing, asset, and tax treatment capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) Evaluated other software options. This option would introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) Address cloud possibilities. This option is expensive and has an unclear timeline roadmap; (4) wait until a future upgrade cycle. This option introduces technical risk; (5) Upgrading to a newer version of current solution. This is the preferred option as it will provide more frequent software upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.	2027-02-01	2028-02-28	-1.00	-	671,749	ROM	-	-	-	-	-	-	-	378,180	-	-	125,723	252,457	-	-
180	2027	Enterprise Risk Management	Software(Intangible)	Corporate	The project will implement software to streamline Enterprise Risk Management (ERM) processes, improve efficiency, provide risk identification and repository tools, and deliver real-time risk data. The Enterprise Risk Team (ERT) collaborates with Risk Owners (ROs) annually to identify new risks, update existing ones, quantify impacts and likelihoods, document mitigation plans, identify trends, and formulate risk tolerance metrics. This process involves iterative exchanges between ERT and ROs to align on content. This effort culminates in multiple risk reps presented annually to senior management and the Board of Directors (BoD). The manual Enterprise Risk Management (ERM) process is intensive and time-consuming, creating risks of human error that can inaccurately quantify risks, introduce data anomalies, and create version tracking issues. The current process results in inefficient use of time by risk analysts and risk owners, limits the breadth of analysis, and affects the Company's ability to promptly identify, analyze, and communicate risks to senior leaders, potentially causing delays in responding to emerging risks. Due to its lengthy nature, the manual process is conducted only once a year but needs to be performed more frequently for proactive enterprise risk management. Utility industry peers use software to more effectively manage enterprise risk management programs. This project creates value for the Company by: (1) providing real-time risk information to stakeholders including the risk team, risk owners, senior management, and the Board of Directors (BoD); (2) supporting proactive risk management; (3) establishing a centralized repository for risk identification, management, and mitigation plans; (4) reducing waste through simplified processes; and (5) enhancing efficiency for risk owners and analysts. The project scope includes: (1) creating risk analysis templates and tools for automated reporting; (2) establishing automated workflows to perform risk updates; (3) configuring dynamic templates that prompt the risk owners based on prior selections; (4) organizing risk assessments through an active and searchable data repository; (5) creating new reports and executive dashboards; (6) migrating data; and (7) setting record retention rules. Alternatives considered include: (1) Continuing to use the current manual processes. This alternative was not chosen due to inefficiencies, poor quality results, and limited frequency of risk reviews. (2) Building a custom internal enterprise risk solution. This alternative was not selected because it does not incorporate best practices available in risk management software provided by industry leaders. (3) Implementing a software solution from a leading enterprise risk solution vendor. Although this introduces new license and ongoing support costs, it is preferred since it incorporates industry best practices, ensures application reliability, security, stability through vendor support, and provides innovation and insights via risk information reporting through management dashboards. Additionally, it aligns the Company with utility industry peer practices for more effective enterprise risk management.	2027-07-01	2028-07-03	-1.00	184,200	80,666	ROM	-	-	-	-	-	-	-	7,253	-	-	2,528	4,725	-	-
181	2027	Product Family Enhancements-Corp	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	1,031,882	74,206		683,519	82,215	1,957	163,025	381,391	-	54,931	46,750	15,825	39	7,431	23,455	-	-
182	2027	Product Family Enhancements-Corp	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	-	353,192		-	-	-	-	-	-	-	222,511	186	-	67,010	155,315	-	-
183	**SUBTOTAL**	**2027 Corporate**										**683,519**	**82,215**	**1,957**	**163,025**	**381,391**	-	**54,931**	**1,022,249**	**16,011**	**39**	**435,604**	**576,995**	-	-
184	2027	Energy Assistance Enhancements a	Software(Intangible)	Customer	The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy (CARE) project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interfaces and updates to SAP to process various requests. Upcoming modifications will be identified following ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services (DHHS) and Michigan Public Service Commission (MPSC) to prioritize the list of changes. Each grant year, DHHS and MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track active CARE customers, and how they will administer the Michigan Energy Assistance Program (MEAP) benefits through bill credits and arrears forgiveness. The criteria changes significantly each year; therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requirements are not fulfilled, the Company is at risk of losing state Low Income Energy Assistance Fund (LEAF) funds to assist low-income customers with paying their energy bills, thereby increasing the customers risk of shutoff for non-payment. In addition, our energy assistance programs function within all software platforms in the company which consistently need enhancements and updates. The project will provide the following value: (1) complete modifications to internal SAP application and Agency Portal to receive LEAF funding, which can be used to provide customers the bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LEAF funding; and (3) complete modifications to customer facing platforms. The project scope includes: (1) updating the enrollment and status process; (2) allowing for flat monthly bills; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and Michigan Public Service Commission; (6) updating CARE dunning process; and (7) updating the assistance portal (CE PASS) functionality to enhance Agency Self-Service. Alternatives considered include: (1) continue with current process. This alternative was not chosen because it would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization. This alternative was not selected because it would remove ownership and visibility into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. This option was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems such as SAP, a large internal system that supports broad areas of the business, and the Agency Portal, an internally developed web application, therefore a single cloud or third-party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.	2027-01-01	2027-12-31	0.00	-	292,962		-	-	-	-	-	-	-	184,566	-	-	105,826	78,740	-	-
185	2027	Product Family Enhancements-Cust	Software(Intangible)	Customer	The Customer initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	2,563,822	600,183		1,698,275	30,191	5,952	458,763	1,025,508	-	177,861	378,115	3,113	-	74,552	299,941	-	508
186	2027	Product Family Enhancements-Cust	Software(Intangible)	Customer	The Customer initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	-	234,667		-	-	-	-	-	-	-	147,840	-	-	45,380	102,460	-	-

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For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(l)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(v)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
187	2027	Rate Change Maintenance	Software(Intangible)	Customer	The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements. For the Company to continue to meet and comply with certain MPSC requirements and to enable it to update its rates when rate changes are approved, there is a need to make periodic updates/modifications to existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers. The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that includes new surcharges, price changes, and energy efficiency programs. The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Company's back-end system for more efficient rate changes. Alternative considered include: (1) a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and the time it would take for testing of this model; and (2) Instead, the Company chose to leverage onshore resources to plan, coordinate, and execute the rate changes. This option was selected as it supports the Company's operation model for rate changes.	2027-01-01	2027-12-31	0.00	-	298,844		-	-	-	-	-	-	-	188,272	-	-	13,783	174,489	-	-
188	2027	SiteCore Secondary Upgrade 2027	Software(Intangible)	Customer	The project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for the consumersenergy.com website, a channel many customers use for accessing account information and bill payment. Sitecore requires regular upgrades to adhere to the vendors support lifecycle to ensure system reliability, take advantage of new application features, maintain current security updates, and improve the customer's website experience. The project will add value for the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to date security posture; and (3) supporting the Company's Customer Experience Index (CXi) goals by improving reliability and performance. The project scope includes: (1) upgrading the Sitecore content management software to the latest available version. Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the need to prevent the application from falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Migrating to a cloud solution was also considered. This alternative was not chosen due to the cost/benefit analysis of re-architecting the Company's current Sitecore implementation to facilitate cloud migration that is not viable at this time; and (3) Rejecting these alternatives, the Company chose to upgrade Sitecore on a two-year cycle because it provides up to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.	2027-01-18	2027-10-15	-1.00	-	105,765	ROM	-	-	-	-	-	-	-	66,632	-	-	66,632	-	-	-
189	**SUBTOTAL**	**2027 Customer**										**1,698,275**	**39,191**	**5,952**	**458,763**	**1,025,588**	**-**	**177,861**	**965,425**	**3,113**	**-**	**206,174**	**655,630**	**-**	**500**
190	2027	Advanced Distribution Management S	Software(Intangible)	Electric	The Advanced Distribution Management System Upgrade (ADMS) project will enhance operator experience, simplify maintenance, and provide more powerful and flexible system functionalities. These include advancements in Fault Location, Isolation, and Service Restoration (FLISR), waste elimination within Maestro, the introduction of independent line sensors, a redesign of temporary conditions, and will incorporate operational views of schematics. The project will also be replacing the outdated hardware. The current ADMS lacks several critical features and improvements that are essential for enhancing operator experience, system maintenance, fault detection, and response capabilities. The existing system struggles with: (1) the current FLISR functionality does not adequately support complex protection requirements and manual switching steps, leading to inefficiencies and potential errors; (2) operators face challenges with passthrough edits and managing conflicts related to devices with tags or temporary conditions, resulting in frequent system reloads and inaccuracies in the as-operated system; (3) the temporary conditions subsystem is cumbersome to use, hindering efficient operations and the ability to support mobile substation and; (4) the current schematic tools do not provide operational views or the ability to save and share views, limiting situational awareness and usability for operators. These gaps result in operational inefficiencies, increased maintenance efforts, and reduced effectiveness in fault management and system operations. Addressing these issues is crucial for improving the overall functionality, usability, and maintenance of the Distribution Management System. (5) The Company runs the risk of increased failure if it does not regularly refresh the infrastructure. The project will add value by: (1) improving the user interface and overall experience of the operators, (2) increasing the flexibility and configurability of FLISR, allowing for better support of complex protection requirements and improving solutions for manual switching steps, (3) enhancing the usability of schematics, providing operational views and the ability to save and share views for better situational awareness, (4) developing advanced switch order functionality to support more robust and efficient operations, (5) allowing ADMS to pull real time network model from GIS Utility Network and (6) improving stability and availability of business-critical applications by proactively replacing hardware before it fails. The scope of the project includes: (1) replacing ADMS hardware, (2) upgrading the existing ADMS platform to the latest packaged version, (3) adding in the feature improvements for Temporary Condition Redesign, Maestro Conflict Resolutions, Independent Line Sensors, FLISR and Schematics, (4) implementing new extraction tool, (5) testing the new functionality in various possible scenarios, and (6) communicating and training users on the new functionality. Alternatives considered include: (1) using outdated equipment and current version of ADMS. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact the Company's ability to respond effectively in storm situations. (2) Moving to a cloud version of ADMS. This option was not selected as the current public cloud platforms do not offer the high security environment required for the ADMS application. Consequently, the vendor platform was not built for cloud environments. (3) Replacing the hardware and upgrading ADMS. This option was selected to alleviate the above concerns.	2026-03-02	2027-11-11	-1.00	11,035,811	892,993	ROM	8,202,343	24,407	1,708,520	2,911,744	1,531,672	-	2,026,000	384,686	40,000	-	192,550	192,136	-	-
191	2027	Application Currency-Electric-O&M	Software(Intangible)	Electric	The Electric/Generation/Renewables Engineering and Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increases cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric/Generation/Renewables Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Electric/Generation/Renewables Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2027-01-01	2027-12-31	-1.00	-	217,850		-	-	-	-	-	-	-	217,850	-	-	193,807	24,044	-	-
192	2027	Electric Geographic Information Syst	Software(Intangible)	Electric	This project will replace the existing design software for Electric Low Voltage Distribution (LVD) with a new solution that will be fully integrated to the ESRI (Environmental Systems Research Institute) GIS (Geographic Information System) platform which is already in use by the Company. This new solution will leverage GIS asset data to generate engineering designs. This will allow the Electric teams to have a single source and format to view asset data, construction drawings and redlines in both the back office and field. This change will further enable improvements to the mobile platform in quality of data that is used by the closeout team. This will also reduce the back end posting effort by using the native GIS data format; improving data quality by reducing the re-keying of data. The current design software creates waste in three areas for many teams within Electric including Low Voltage Distribution (LVD) Engineering, Field Leaders, and Customer Energy Management (CEM) Service Designers. (1) The current software does not support the native GIS data format and will not support future enabling work management needs. This causes waste and room for error by having to redraw designs in GIS that have already been created and prevents optimization of the work process. (2) It is not able to integrate to SAP to automatically order materials based on the design. (3) The current software lacks needed mobile functionality due to its lack of support for the native GIS format. The designs are not georeferenced to the exact location and can't fully utilize redlining capability which causes a significant impact to data quality and crew performance. This project will add value to the Company and its employees through: (1) eliminating the need to duplicate all design work as it is in both the design system and GIS; (2) enabling mobile editing and redlining on the design in GIS; (3) enabled integration to SAP; and (4) utilizing the capabilities of the next generation GIS platform that will be delivered through an in-progress business case. The project scope includes: (1) installing a new solution that will integrate to GIS; (2) utilizing GIS geospatial and asset information data and the GIS platform for generating Electric LVD engineering designs; (3) integrating to and from SAP to automate Compatible and Mass Unit material ordering capability; (4) installing new and upgrading existing geospatial platform infrastructure to support additional users (Electric LVD designers, Field Leaders, Planners, Schedulers, etc) of GIS; (5) integrating to ProjectWise (engineering content management system); (6) configuring mobile toolset; (7) re-engineering the existing GIS data model to handle asset life cycle; and (8) configuration for new ArcGIS services.	2025-09-09	2029-02-22	-0.47	6,241,626	659,758		2,576,069	1,100,000	-	1,056,849	-	-	419,220	136,794	-	-	136,794	-	-	-
193	2027	Electric GIS Utility Network Transfor	Software(Intangible)	Electric	This project will transform the Company's current Geographic Information System (GIS) platform to the Environmental Systems Research Institute (ESRI) Utility Network Model and establish a unified GIS for large scale distribution (HVD), low voltage distribution (LVD), and substations data model. This transformation aims to optimize core engineering and operational processes, technologies, and data. The Company's GIS for electric records is expanding as an authoritative source for asset connectivity, location and health information. However, growing business requirements for advanced analytics and regulatory mandates necessitate more granular geospatial insights. Existing functionality does not meet business partner needs, and GIS data is refreshed in batch mode once a day, leading to inefficiencies with real-time systems. Managing HVD and LVD data in different models remains challenging. The Company's past implementation of ESRI's GIS for Electric, version 10.8.1, will be unsupported after March 1, 2028. Critical third-party solutions supporting key editing and business functionality are also ending support without upgrade options, posing risks for security updates. ESRI's development focus is shifting to the ArcGIS Utility Network Management extension, ArcGIS Enterprise, and ArcGIS Pro. The vendor's development team has reached the limits of ArcMap and the geometric network's capabilities and will no longer build additional functionality. Future development and enhancements are focused on the next-generation technologies of the Utility Network and ArcGIS Pro. ESRI utility solution partners are also moving their product lines away from the geometric network, soon supporting only the Utility Network. The project creates value for the Company by: (1) mitigating risks associated with product support and of life; (2) enabling detailed asset management and location based analytics to bring clearer understandings around the assets that support energy delivery; (3) increasing productivity through use of shortcuts, templates, and streamlined workflows within the software; (4) providing extensive, out-of-the-box tracing tools; (5) providing 3D visualization functionality; (6) enabling users with editing tools, giving them guidance at every step of the process for developing workflows and enforcing stronger data integrity; (7) viewing the up to date network in a map or schematic diagram and be able to quickly toggle back and forth between them; and (8) enabling archiving and historical versioning to view the state of the electric network over time. All of these capabilities will result in greater insight and efficiency that improves the safety and delivery to customers of Michigan. The Utility Network enables implementation of third-party tools that will allow us to keep the operational model more up to date as circuits with temp conditions and/or control tags can be imported as needed. The project scope includes: (1) upgrading all database, web, and application servers to supported Windows version; (2) upgrading end user application from ArcGIS Desktop to ArcGIS Pro; (3) migrating and converting LVD and HVD GIS data from geometric network data schema to the Utility Network, iteratively publishing data to new model for consumption; (4) reconfiguring electric applications that are integrated with GIS or that consume GIS data; and (5) creating substation asset model. Alternatives considered include: (1) Continue to use geometric network. This alternative was not selected because the architecture is at the end of its life. Additionally, dependent third-party solutions are moving away from the geometric network, making it unsustainable for continued use. (2) Moving to Utility Network and migrating to a supported platform. This alternative was chosen to enable the Company to leverage a cloud-based solution and provide options for utilizing third-party solutions.	2027-07-01	2029-12-04	-1.00	20,408,033	5,007,911	ROM	4,108,314	1,800,000	-	370,745	1,702,591	-	234,978	1,559,856	360,000	-	360,205	758,458	-	61,193
194	2027	Integrated Energy Management Platf	Software(Intangible)	Electric	This project will reduce data center assets running PCI Energy Solutions by migrating into vendor cloud hosting solution. This will optimize vendor support, reduce operational costs (upgrades, server maintenance) and allow the Company to leverage new cloud capabilities. PCI Energy Solutions (PCI) provides software that Company uses to fulfill the Federal Energy Regulatory Commission (FERC) requirement of communicating unit availability to the Regional Transmission Operator and become more efficient at buying and selling electricity in the wholesale market. Due to the solution being Company hosted, the Company is not able to leverage benefits of the full functionality in the vendor's cloud hosting solution (Software as a Service (SaaS)). The complex nature of the solution requires various IT and business support teams to monitor, maintain and upgrade the system. Due to the critical nature of the application, the Company is looking to the SaaS hosting to benefit from the uptime SLA of 99.95% and the streamlined operational support for faster issue resolution. This project creates value for the Company by: (1) utilizing the vendor's SaaS environment which provides efficiencies for timely operational support. Currently, as an example, IT sends PCI a database copy so they can replicate the Company's environment in the vendor's system. This leads to waste of resources, time and increased support costs. (2) Freeing up resources for more value add work. As the Company optimized the organization, it is very important to reduce waste and work on the most valuable items; (3) reducing Oracle footprint; (4) reducing IT labor support costs; (5) reducing ongoing networking equipment replacement and upgrade costs. The project scope includes: (1) planning and executing the data migration; (2) designing and configuring new and existing vendor SaaS components; (3) implementing integrations to CO15 (Commercial Off-The-Shelf) and custom systems; (4) testing; (5) educating and increasing the skills of the employees to leverage the new vendor SaaS services; (6) decommissioning old infrastructure. Alternatives considered include: (1) continue to use the Company hosted installation of PCI. This alternative was not chosen due to the significant waste involved in maintaining the system, the inability to leverage Cloud functionality, and the failure to decrease the reliance on Oracle servers. (2) Move to a different energy market platform. This alternative was not selected because the different platform would have lesser options and would not be able to utilize PCIs bid to build process. (3) Move to the vendor SaaS. This alternative was selected as the Company will utilize the latest technology and optimize operational support.	2027-05-02	2028-03-16	-1.00	4,329,636	1,662,202	ROM	4,194,207	3,357,911	-	406,262	45,000	-	385,034	1,611,270	-	-	308,270	1,303,000	-	-
195	2027	Product Family Enhancements-Elect	Software(Intangible)	Electric	The Electric/Generation/Renewables Engineering and Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric/Generation/Renewables Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric/Generation/Renewables Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric/Generation/Renewables Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	719,345	188,564		719,345	20,000	-	185,588	453,062	-	60,695	188,564	-	-	34,331	154,233	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
196	2027	Product Family Enhancements-Elect	Software(Intangible)	Electric	The Electric/Generation/Renewables Engineering and Operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric/Generation/Renewables Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric/Generation/Renewables Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric/Generation/Renewables Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	-	120,493		-	-	-	-	-	-	-	120,493	2,280	-	52,124	66,090	-	-
197	2027	Service Restoration Artificial Intellige	Software(Intangible)	Electric	Artificial Intelligence (AI) Machine Learning (ML) can enhance decision-making during restoration events by quickly evaluating multiple datasets, reduce non value-added time, and continuously improve through learning. This project will show the value of AI ML in Storm Declarations, Resource Planning, Resource Utilization/Crew Movements, and Asset Identification. The Company faces challenges in efficiently managing storm response and restoration efforts. Historically, storm declarations, resource planning, and crew movements have relied on manual processes and estimations, leading to delays and inefficiencies. The need for a more effective and timely response during restoration events has become increasingly critical, especially given the complexity and scale of modern storm events. This project creates value for the Company by (1) enhancing the storm response capabilities. This will enable faster and more consistent decision-making during restoration events, optimizing resource planning and crew movement and improving asset identification. (2) Delivering business value. The utilization of AI ML in service restoration processes is expected to reduce non-value-added time, improve public safety and create savings for customers. (3) Providing customer value. The AI ML applications will benefit customers by optimizing storm declarations, resource planning, crew movement and asset identification. These enhancements will lead to more efficient outcomes, faster restoration times and improved public safety. Furthermore, AI ML's learning abilities enable the decision-making to continuously improve, and those learnings have the durability to live beyond the human experience and mitigate learning curves as people transition from role to role. The project scope includes: (1) developing AI ML models for storm declarations, resource planning, resource utilization/crew movements, and asset identification, (2) Integrating with existing systems like Advanced Distribution Management System (ADMS), Customer Resource Manager (CRM) and Catastrophic Crewing in house built application. (3) Training and deploying. (4) Performance monitoring and (5) customer communication. Alternatives considered include: (1) continuing with the manual process. This option was not chosen because it results in underutilized crews, non-value-added time, and increased human error and difficulty. (2) Purchasing a storm work management solution. This option was not chosen due to its high cost, vendor dependency during the Company's most critical times, and complexity. (3) Creating an AI ML solution. This option was selected as it meets the criteria and will be scalable across service restoration and electric distribution.	2026-03-01	2027-05-30	-1.00	1,380,332	170,130	ROM	496,515	-	-	346,783	-	-	149,732	59,945	-	-	59,945	-	-	-
198	2027	20% ROM Adjustment - Electric	Software(Intangible)	Electric	This is for the 20% ROM Adjustment for IT projects.							(3,400,777)	(1,076,464)	(343,704)	(807,107)	-	(999,993)	(173,509)								
199	**SUBTOTAL**	**2027 Electric**										**20,286,794**	**6,382,316**	**1,709,020**	**5,277,072**	**3,732,225**	-	**3,275,639**	**4,279,455**	**402,280**	-	**1,316,025**	**2,497,360**	-	**61,193**
200	2027	Application Currency-Electric & Gas	Software(Intangible)	Electric & Gas Shared	The Electric and Gas Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2027-01-01	2027-12-31	-1.00	-	541,866		-	-	-	-	-	-	-	341,375	-	-	305,695	35,681	-	-
201	2027	Application Currency-Operational Te	Software(Intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2027-01-01	2027-12-31	-1.00	-	194,042		-	-	-	-	-	-	-	122,247	-	-	122,247	-	-	-
202	2027	Iron Enterprise Edition 2027 Upgrad	Software(Intangible)	Electric & Gas Shared	This project will upgrade Iron Enterprise Edition (IEE), which collects the reads from meters to ensure non-estimated bill accuracy. Iron Enterprise Edition (IEE) is the Company's keystone application of the Advanced Metering Infrastructure (AMI), that provides billing data that includes time of use data. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. Iron Enterprise Edition (IEE) is a key component in keeping the Company current, with billing capacity, stability, and accuracy obligations. This project creates value for the Company by: (1) ensuring the features and functionality needed to meet and exceed customer satisfaction and billing accuracy are available to business partners and IT; (2) meeting Information Security's requirement to keep applications patched and protected from cyber attack. The scope of this project includes: (1) upgrading the Iron Enterprise Edition (IEE) applications to the next appropriate versions; (2) migrating the database to the next version required by the application; and (3) replacing hardware required by the next version to maintain operating system currency. Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because it would decouple Iron IEE (Consumers Energy's Meter Data Management) from the Iron security infrastructure introducing application instability, security and dependency risks to the utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Iron applications, creating more expense to support and no ability to leverage updated tool capability. (2) replacing the platform. Replacing IEE/MDM would require the application business owners to undertake a new initiative mirroring the expense and effort that went into the initial multi-million dollar project.(3) performing the upgrade is the best alternative. This option is superior for both customers and the Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Iron products.	2027-01-14	2027-11-14	-1.00	-	265,814	ROM	-	-	-	-	-	-	-	167,463	-	-	167,463	-	-	-
203	2027	Product Family Enhancements-Elect	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric and Gas operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	1,826,301	307,743		1,209,742	-	29,699	217,220	887,934	-	74,889	193,878	-	-	46,883	146,929	-	67
204	2027	Product Family Enhancements-Elect	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. *Additionally,*enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	-	566,033		-	-	-	-	-	-	-	356,601	15	-	47,634	308,910	-	41
205	**SUBTOTAL**	**2027 Electric & Gas Shared**										**1,209,742**	-	**29,699**	**217,220**	**887,934**	-	**74,889**	**1,101,564**	**15**	-	**689,921**	**491,519**	-	**108**
206	2027	ARP-Radio	Network	IT/Digital Foundation	This project will refresh hardware to include: 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices, vehicle consoles in service trucks, other communications equipment, and associated test equipment. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 10-year lifecycle basis. Cellular modems are refreshed on a five-year life cycle basis. Amplification systems are refreshed on a 15-year life cycle. 800MHz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customers service and critical infrastructure. Company radio and cellular systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing or becoming obsolete. The refresh of this equipment in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety. This project creates value for customers and the Company by (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure. The project scope consists of: (1) scheduled replacement of radios, modems, consoles; and (2) installing additional radios, modems, and console assets to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters and systems. The alternatives considered include: (1) Replacing the existing units with new units from other radio and modem manufacturers; (2) Purchasing new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.	2027-01-01	2027-12-31	-1.00	1,738,734	93,246		910,749	-	858,059	23,501	20,952	-	8,237	58,745	-	56,102	1,383	1,260	-	-
207	2027	ARP-Collaboration	New Computers / Hardware	IT/Digital Foundation	This project will replace the Company's obsolete or out-of date audio, visual, telephony and other communication collaborative tools and equipment. When collaboration assets used to support customer interactions and business operations are obsolete or out-of-date, they are more difficult to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project creates value by: (1) ensuring the stability and reliability of the Company's audio, visual, telephony, and other communications systems; and (2) migrating to new collaboration assets. The project scope consists of: (1) replacing aging collaboration assets; and (2) installing new collaboration assets to meet evolving business requirements. The alternatives considered include: (1) continuing to operate collaboration assets beyond a five-year refresh cycle, or (2) refreshing collaboration assets based on a five-year refresh cycle while evaluating the health of the asset and evolving business requirements. The alternative to operate the collaboration assets beyond a five-year refresh cycle was not selected due to the risk of asset failures would cause stability and reliability issues for employees supporting our customers, as vendors do not provide extended support after five years. The Company chose to refresh the collaboration assets based on a five-year refresh cycle and evaluate the health of the asset and evolving business requirements to reduce the risk of impacting the productivity of employees supporting our customers.	2027-01-01	2027-12-31	-1.00	730,273	167,315		483,733	-	283,259	48,908	136,864	-	14,702	105,408	-	13,356	25,902	66,150	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST-BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
208	2027	ARP-Field Device Asset Management	New Computers / Hardware	IT/Digital Foundation	This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility. When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices before they fail; and (2) allowing field workers to complete their job tasks. The project scope consists of replacing field device assets according to the four-year refresh cycle. Alternatives considered include: (1) using outdated equipment. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact meter readers' ability to complete job tasks. It would also complicate the Company's efforts to meet the MPSC's meter reading factor and consecutive estimated targets, and it could cause applications to run poorly or stop functioning; (2) The second alternative considered was to replace the hardware. The Company selected this option to alleviate the above concerns.	2027-01-01	2027-12-31	-1.00	5,534,405	3,556		3,865,990	-	3,571,344	68,892	-	-	25,754	2,240	-	1,822	144	174	-	-
209	2027	ARP-Operational Technology Suppo	New Computers / Hardware	IT/Digital Foundation	The Asset Refresh Program (ARP)-Operational Technology (OT) Support Common project will replace dated and obsolete servers shared by Electric and Gas on a rotating five-year refresh schedule. When Operational Technology Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure. The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure.	2027-01-01	2027-12-31	-1.00	1,471,974	147,459		975,036	-	931,997	31,328	-	-	11,711	92,899	-	86,940	5,959	-	-	-
210	2027	ARP-Operational Technology Suppo	New Computers / Hardware	IT/Digital Foundation	The Asset Refresh Program (ARP)-Operational Technology (OT) Support Electric project will replace dated and obsolete servers on a rotating five-year refresh schedule. When Operational Technology Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure. The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Electric SCADA.	2027-01-01	2027-12-31	-1.00	1,833,952	275,742		1,833,952	-	1,714,000	87,312	-	-	32,640	275,742	-	261,000	14,742	-	-	-
211	2027	ARP-Printer Asset Management (PAI	New Computers / Hardware	IT/Digital Foundation	This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one. When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications. The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. This does not mean that all printers are replaced after five years merely that printers are assessed on a five-year cycle for possible replacement. The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years would require the printers to be assessed monthly to ensure they are not run to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.	2027-01-01	2027-12-31	-1.00	675,450	8,454		447,418	-	436,804	7,726	-	-	2,888	5,326	-	83	5,064	162	-	16
212	2027	ARP-Workstation Asset Management	New Computers / Hardware	IT/Digital Foundation	This project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates. When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks. The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. The alternatives considered were to purchase extended maintenance, move some of these assets to the cloud with the Digital -Hybrid Cloud and Data Center Migration project, or to replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remaining the five- to seven-year cycle as it is the most cost-effective option.	2027-01-01	2027-12-31	-1.00	6,997,985	101,362		4,635,452	-	4,453,827	81,517	71,506	-	28,602	63,858	-	14,413	14,060	1,518	-	33,867
213	2027	Operational Technology (OT) Datace	New Computers / Hardware	IT/Digital Foundation	The OT environment consists of systems supporting the control and monitoring of electric grid, electric generation, gas compression, and natural gas pipeline. These systems are critical for safe and reliable natural gas and electric delivery. The OT Datacenter Migration project enhances the Company's capabilities by co-locating to an enhanced datacenter at a vendor facility. The Company's current datacenter for the OT environment needs modernization and relocation from the Parnall Data Center. The current location is not the preferred location to house servers and systems critical to the control of the Electric Grid or Gas Pipeline due to the close proximity to a railway system. The climate conditioners in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns . The location of the datacenter in the basement of the Parnall building is nearby to the main water piping for the building. There have been instances of water infiltration in the past. This project creates value for the Company by significantly strengthening capabilities through: (1) mitigating legacy physical and location risks at the current Parnall site; (2) migrating the OT infrastructure to a modern, highly secured environment with redundancy in climate conditions; and (3) better datacenter facilities support with a guarantee of redundant power. The scope of the project includes: (1) migration of the OT environment from the Parnall Data Center to a co-located vendor data center; (2) re-validation of the OT Production and Disaster Recovery procedures once migration is completed; (3) migration of IT systems required for supporting the OT environment; and (4) decommission the existing OT environment from the Parnall location. The Company performed an analysis of alternatives to expand capabilities as well as address constraints and risks: (1) Remain at the current Parnall Data Center; (2) migrate OT environments to the Cloud; and (3) relocate to a third-party co-location facility. Current industry best practices do not recommend migration of OT environments to the cloud. The co-location vendor provides the building, cooling, power, and physical security the Company lacks for its servers, storage, and other computing and networking equipment at the current Parnall location. Based on the analysis, the Company decided to implement the third alternative.	2026-06-30	2027-12-11	-1.00	7,749,620	1,856,450	ROM	2,224,464	119,713	1,199,526	250,175	450,913	-	204,140	599,949	-	-	259,749	340,200	-	-
214	2027	20% BVM Adjustment - IT/Digital Fo	New Computers / Hardware	IT/Digital Foundation	This is for the 20% BVM Adjustment for IT projects							(444,807)	(20,943)	(290,994)	(80,074)	(50,183)	-	(46,836)	-	-	-	-	-	-	-
215	2027	Application Currency-IT/Digital Foun	Software(Intangible)	IT/Digital Foundation	The Application Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms area are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2027-01-01	2027-12-31	-1.00	-	262,429		-	-	-	-	-	-	-	165,330	-	-	165,330	-	-	-
216	2027	Application Currency-IT/Digital Foun	Software(Intangible)	IT/Digital Foundation	The Infrastructure Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Infrastructure Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Infrastructure Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2027-01-01	2027-12-31	-1.00	-	38,590		-	-	-	-	-	-	-	24,312	-	-	24,312	-	-	-
217	2027	AxWay Secure Transport 2027 Upgr	Software(Intangible)	IT/Digital Foundation	Axway SecureTransport is the official Consumers Energy multi-protocol Managed File Transfer (MFT) gateway for securing, managing, and tracking data file flow for business partners and external vendors. Files impacting billing, HR, Supply Chain, Finance, Alternate Energy Programs, Front Office, Back Office, Device Management, Outage Management and Business Reporting functions utilize these services. This project will update the platform to the current software version, enabling cost saving operational enhancements while retaining data security and platform supportability. As Axway Secure Transport is the public-facing MTF gateway, maintaining platform version integrity is critical to ensuring it remains secure and supportable in the event of a cyber attack, outage or other critical incident. A prolonged outage or incident, for any reason, compromises the ability of the Company to perform mission-critical business transactions in finance, operations and direct customer support. Upgrading this application also gives the Company the opportunity to properly scale SecureTransport and take advantage of the growing demand for additional, cost-savings features of the tool, such as managing internal Electronic Data Interchange transactions. The value this project brings the Company, its customers and business partners by: (1) addressing known problems and limitations of the current software platforms. (2) ensuring continued secure, scalable, and critical data transmission services running through Axway. (3) creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste. (4) merging/streamlining the company data file transfer services reduces cyber attack vectors and creates a better, more easily maintained and monitored security model. The scope of this project includes (1) upgrading the application and database to the current released and supported versions. and (2) enabling and testing in scope file transfer processes. Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because the Axway SecureTransport platform handles critical Company financial, HR, and operational transactions--the risk associated with problems stemming from an outdated and unsupported version is too high. (2) replacing the platform. The estimated project costs and timetable for replacing the business functions currently performed by the existing Axway SecureTransport platform would be extensive, and operationally, it is not well suited for a SaaS or hybrid cloud solution. In addition to significant platform, implementation, and functional testing costs, replacing it would require extensive coordination and testing with all of the internal and external account holders, taking upwards of one calendar year. (3) upgrading the platform. This project provides the Company the best, most cost-effective alternative, balancing risk, known risks, and ever-growing business capacity and productivity.	2027-01-01	2027-09-01	-1.00	-	400,191	ROM	-	-	-	-	-	-	-	252,120	-	-	252,120	-	-	-
218	2027	Data & Analytics Platform Rationaliz	Software(Intangible)	IT/Digital Foundation	This project will optimize the Data & Analytics system landscape by creating connections, migrating data into the Data Lake in the cloud, and building visualizations from the data in the Data Lake. The IT Data & Analytics legacy systems (SingleStore Database (SSDL), SAP Business Warehouse (SAP BW), SAP Business Objects (SAP BOBJ), Native HANA, the SAP BW Portal, and BusinessObjects Data Services BODS) are outdated, inefficient, and becoming duplicative in nature with the introduction of DL 2.0. If these legacy systems are not retired, they will continue to cost the Company money as major investments are needed to maintain and support them. This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources. The project scope includes: (1) the assessment of the existing Data & Analytics platforms including SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organization change management; and (7) the retirement/decommissioning of the legacy platforms and applications. Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company's cloud strategy. (2) Lift and shift these on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces. (3) Migrate all data sources to DL 2.0 and retire legacy systems. This alternative was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.	2025-04-07	2027-12-31	0.43	9,019,671	1,319,807		2,187,744	241,077	-	702,716	897,084	-	346,868	370,717	-	-	60,862	309,855	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
219	2027	Enterprise Service Bus 2026-2027 U	Software(Intangible)	IT/Digital Foundation	This project will upgrade the current ESB software versions in use at the company. This will also implement a container management system, which deploys, manages, and scales microservices or applications that send or receive data via the service bus, and migrate various services to containers. Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway, be more scalable, secure, and capable of integrating to a service-based environment. The lack of a container management solution prohibits the adoption of a more cloud native approach leading to retaining legacy solutions. The value this project provides the Company includes: (1) implement a container management solution; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies. The project scope includes (1) implementing the current version of all applications that are part of the ESB application, database version, and required database drivers and (2) implementing a Kubernetes solution for container management and migrate targeted services that are identified as microservices to containers. Alternatives considered included: (1) Accept the current version levels and continue to pay for extended support costs and accept technical obsolescence risk. (2) Only upgrade the existing applications. (3) Upgrade all of the applications as well as evolve the cloud-based instance to a more cloud native architecture by converting containers and implementing a Kubernetes solution to manage the containers. This option was selected because it best meets the Company needs for the near future by maintaining vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.	2026-09-01	2027-11-22	-1.00	1,331,120	1,042,944	ROM	881,734	364,704	-	389,822	-	-	187,207	637,245	131,670	-	505,575	-	-	-
220	2027	HR Support Pack and Business Soft	Software(Intangible)	IT/Digital Foundation	The Human Resources (HR) Support Pack and Business Software Inc (BSI) upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll. This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company. oAlternatives considered include: (1) not upgrading to the current support packs, which results in noncompliance with financial rules and regulations and inaccurate payroll. (2) there is no economical cloud solution, so this option was not entertained. (3) the Company decided the best alternative is to apply the appropriate support pack upgrades. This option is preferred because it enables the Company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.	2027-02-06	2027-12-29	0.00	-	665,132		-	-	-	-	-	-	-	419,033	-	-	36,314	355,306	-	27,413
221	2027	Product Family Enhancements-Appli	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	311,154	30,590		206,109	13,264	5,288	79,634	69,868	-	38,054	19,272	292	99	7,416	11,466	-	-
222	2027	Product Family Enhancements-Appli	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	-	156,871		-	-	-	-	-	-	-	98,829	8,005	-	51,173	39,650	-	-
223	2027	Product Family Enhancements-Infras	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software & hardware and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	402,938	130,035		266,906	2,124	29,401	116,147	67,114	-	52,120	81,922	2,069	59	21,138	58,657	-	-
224	2027	Product Family Enhancements-Infras	Software(Intangible)	IT/Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	-	73,484		-	-	-	-	-	-	-	46,295	279	10,410	6,733	28,873	-	-
225	2027	20% ROM Adustment - IT/Distal Fo	Software(Intangible)	IT/Digital Foundation	This is for the 20% ROM Adjustment for IT projects.							(176,347)	(60,941)		(77,994)			(37,441)						-	
226	**SUBTOTAL**	**2027 IT/Digital Foundation**										**18,274,364**	**656,939**	**13,243,599**	**1,837,641**	**1,624,128**	-	**912,056**	**3,219,242**	**142,315**	**444,383**	**1,457,977**	**1,213,271**	-	**61,297**
227	2027	ARP-Cyber-Common	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions. When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades. The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warrant repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.	2027-01-01	2027-12-31	-1.00	1,453,118	16,664		761,143	-	706,711	38,244	1,942	-	14,246	10,498	-	3,150	7,348	-	-	-
228	2027	ARP-Cyber-Electric	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions for Electric. When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades. The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warrant repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.	2027-01-01	2027-12-31	-1.00	470,780	19,377		470,780	200	421,200	32,282	1,800	-	15,298	19,377	-	5,000	14,377	-	-	-
229	2027	ARP-Network-Common	Network	Security	This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks. When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks. The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices. The alternatives considered include: (1) continue to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.	2027-01-01	2027-12-31	-1.00	1,515,192	24,980		793,658	8,905	740,418	21,774	14,808	-	7,752	15,737	-	6,300	9,437	-	-	-
230	2027	ARP-Network-Electric	Network	Security	This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks for Electric. When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks. The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices. The alternatives considered include: (1) continue to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.	2027-01-01	2027-12-31	-1.00	22,156	635		22,156	100	19,435	1,632	389	-	600	635	-	100	535	-	-	-

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Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
231	2027	Critical Substation Upgrade	Network	Security	This project will implement enhanced security measures at the Company's critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time. With the enhanced security posture, Consumers Energy will be better positioned to mitigate malicious activity through real-time detection and increase the reliability of electric delivery to our customers. Today, Consumers Energy currently deems 16 substations as business critical to its electric system while an additional 34 substations fall under NERC-CIP compliance. Recent attacks to critical infrastructure have increased the likelihood of an adversary exploiting vulnerabilities at critical substation increasing the risk for large scale outages and customer impact. The Company's current security measures do not allow us to detect, deter, or monitor potential threats on site. Without the ability to monitor these assets in real-time, the Company is vulnerable to an adversary causing destruction without knowledge of when or how the event took place. A phased implementation would allow the Company to systematically mitigate risk to assets deemed most vulnerable. The objective of this project is to implement enhanced security measures to better detect, deter, and respond to threats to the Company's electric substations in real-time. This enhanced security posture will align with other utilities that own and operate substations and mitigate disruption to electric service while improving reliability. Enhanced Security measures that will need to be implemented include but are not limited to: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fence intrusion (which will be accomplished through camera systems); (6) subcontractor work of trenching poles, installing equipment etc.; (7) additional facility lighting; and (8) security equipment maintenance. Alternatives considered include: (1) maintaining the current security perimeter fencing and conducting routine inspections of the site. This alternative was not selected, as it does not provide the ability to prevent, detect, or respond to threats in real-time; (2) hiring contract security guards to patrol the sites. This alternative was not selected as ongoing O&M costs would be expensive; (3) outfitting sites with thermal cameras with built in analytics that would alarm to intrusions and subjects on the properties along with access control measures. This alternative was selected because of lower ongoing O&M costs and enhanced detection abilities.	2026-01-01	2026-12-15	-1.00	11,771,395	1,016,500	ROM	4,585,250	-	2,312,500	1,070,000	562,500	-	640,250	374,500	-	-	374,500	-	-	-	-
232	2027	20% ROM Adjustment - Security	Network	Security	This is for the 20% ROM Adjustment for Security projects.							(480,351)	-	(242,258)	(112,093)	(58,928)	-	(67,073)	-	-	-	-	-	-	-
233	2027	ARP-Physical Security	New Computers / Hardware	Security	The ARP-Physical Security, formerly known as Physical Security Asset Refresh, will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns. The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring alerts, compliance with regulations and guidelines, and faster responses to emergencies and incidents. This could result in an increase of potential security vulnerabilities, associated penalties, and reputational damage. The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reduce gaps in functionality; and (3) optimize overall system performance. Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) advanced analytics on security cameras for monitoring and real time alerting capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems. Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security assets not meeting the industry standard of 5 to 7 years for indoor cameras and 3 to 5 years for outdoor cameras. Alternatives 1 and 2 were not selected due to the risk of security concerns, utilizing equipment that is at end of life and no longer supported, and the risk of a lack of inability to meet regulatory requirements (FERC, NERC, TSA and NRC). The alternative selected maintains compliance, reduces redundancies and gaps in functionality, provides up to date support for the assets and current technological capabilities and optimizes overall performance of physical security systems.	2027-01-01	2027-12-31	-1.00	2,114,320	12,626		1,400,526	-	861,120	110,568	387,504	-	41,334	7,954	-	-	5,434	2,520	-	-
234	2027	Application Currency-Security-Capita	Software(Intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2027-01-01	2027-12-31	-1.00	153,200	10,700		101,480	-	-	70,877	-	-	30,603	6,741	-	-	6,741	-	-	-
235	2027	Application Currency-Security-O&M	Software(Intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrade. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2027-01-01	2027-12-31	-1.00	-	403,127		-	-	-	-	-	-	-	253,970	3,366	-	250,604	-	-	-
236	2027	Enhancements-Security-Capital	Software(Intangible)	Security	This initiative will use Capital funding to make enhancements to existing technology and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements in accordance with accounting rules. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications require a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	868,042	82,802		574,991	272,812	35,988	112,241	106,522	-	47,426	52,165	2,570	-	45,057	4,528	-	11
237	2027	Enhancements-Security-O&M	Software(Intangible)	Security	This initiative will use O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications require a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	-1.00	-	505,846		-	-	-	-	-	-	-	318,683	24,364	12,774	219,193	62,391	-	(38)
238	2027	Forward Web Proxy Services	Software(Intangible)	Security	This project will replace the Company's existing web proxy service platform with a new, modern, and more resilient platform designed to support both secure internet access and advanced data loss prevention capabilities. A web proxy service acts as a secure intermediary between users and the internet, evaluating, filtering, and forwarding traffic while enforcing company security policies. It acts as an intermediary that evaluates, modifies, and forwards the client's requests to the destination web server. This service offers many benefits for the Company such as advanced filtering. Advanced filtering in a forward web proxy service can filter out unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of attacks such as ransomware. The current web proxy platform, implemented in 2021, has caused ongoing operational issues related to web filtering, inconsistent policy enforcement, and intermittent connectivity. These challenges have occasionally limited employee and contractor access to critical internet and cloud-based resources, impacting productivity and increasing security risk. As the Company accelerates its transition to cloud and Software-as-a-Service (SaaS) platforms, maintaining consistent, secure, and reliable internet access is critical. The new platform will provide high availability, improved performance, and enhanced visibility into outbound traffic to ensure that business operations continue seamlessly, even during peak or failover conditions. The platform will also be designed to support flexible deployment models for remote, hybrid, and field-based workers—ensuring that security policies apply consistently regardless of location. In addition to improving reliability, this project introduces data loss prevention (DLP) capabilities as a core function of the web proxy service. These DLP capabilities will help the Company prevent unauthorized transmission of sensitive or regulated information—such as customer data, intellectual property, or operational system details—to unapproved external destinations. Through content inspection, contextual analysis, and integrated policy enforcement, the new solution will identify and block risky behaviors before data leaves the organization. DLP policies will also align with existing information governance frameworks and compliance obligations to provide both proactive protection and auditable oversight of data handling practices. This project creates value for the Company by: (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilize technology to enable the Company to handle all types of different workloads from varying geographic locations and is highly available; (3) using a mature and scalable web proxy service provider; (4) providing Zero Trust by continuously verifying every connection request; and (5) implementing data loss prevention capabilities on our core web proxy services. The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; (3) potentially changing SASE cloud vendors; (4) and implementing data loss prevention for web proxy services. The Security team did extensive research on alternative web proxy services solutions. Alternatives considered include: (1) continue to use and maintain the current web proxy services platform as it currently is implemented. This alternative was not chosen due to the previous operational issues with the platform that make it unreliable. The result of an unreliable system means that employees and contractors are unable to access business critical services such as email, Teams, ServiceNow, SharePoint Online,; (2) Route all internet traffic through the Company's corporate data center. This alternative wasn't chosen because the capabilities of firewalls aren't as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) Perform an evaluation between existing product with expanded feature sets, such as data loss prevention and alternative vendors that could replace current system with modern vendor platform for web proxy services. This option was chosen because it offers additional analysis with the potential to enhance existing, in place, products with features such as enhanced data loss prevention mechanisms, browser isolation (the ability to contain web pages so that the web page can't affect the client workstation) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's company strategy.	2027-01-15	2028-01-30	-1.00	4,478,032	492,770	ROM	2,966,248	2,641,499	-	33,120	105,984	-	185,646	304,715	277,414	-	7,141	20,160	-	-
239	2027	Privileged Access Management Clou	Software(Intangible)	Security	This project will perform the implementation of a Privileged Access Management (PAM) solution to enhance security by securely storing, rotating, and isolating privileged credentials for both human and non-human users. It provides robust monitoring and control of privileged access across on-premises, cloud, and hybrid environments. Additionally, it automates password management, reducing administrative tasks and minimizing the risk of credential exposure. The Company faces significant security risks related to the management of privileged access, including potential data breaches, unauthorized access, and compliance issues. The Company's current methods of managing privileged accounts are often manual, error-prone, and insufficient to address the complexities of modern IT environments. There is a critical need for a robust solution that can automate and secure the management of privileged credentials, provide comprehensive monitoring and control, and ensure compliance with security policies across on-premises, cloud, and hybrid environments. This project creates value for the Company through: (1) securely storing and managing privileged credentials; (2) automating credential rotation; (3) isolating access to prevent unauthorized use; (4) improving compliance with regulatory requirements through comprehensive audit trails, and reporting; (5) increasing efficiency by automating password management; and (6) reducing manual tasks that can be prone to human error. The project scope includes migrating the Company's current system Privileged Access Management (PAM) system to a cloud vendor, implementing new features not available in the current on-prem solution. Alternatives considered included: (1) manual password rotation. This alternative was not chosen because it requires significant time and effort to manage and update passwords manually. It also increases the risk of human error including mistakes, such as forgetting to update passwords or using predictable patterns; (2) Access Control Lists (ACLs). This alternative was not chosen because of scalability issues. ACLs are difficult to manage as the number of users and resources grows. This option also requires regular updates and reviews to ensure accuracy and security; (3) manual audit logs. This alternative was not chosen because it is very labor intensive. It requires significant effort to maintain and review logs manually. The use of manual audit logs increases the risk of inaccuracy by having a higher chance of errors and incomplete records; (4) periodic security reviews. This alternative was not chosen because it is very resource intensive and requires time and expertise to conduct through reviews. Periodic security reviews may also miss issues that arise between review periods; and (5) implementation of a cloud based Privileged Access Management (PAM) solution was the chosen option. It provides robust monitoring and control of privileged access across on-premises, cloud, and hybrid environments. Additionally, it automates password management, reducing administrative tasks and minimizing the risk of credential exposure.	2027-01-16	2027-11-30	-1.00	2,409,688	350,750	ROM	1,596,177	1,395,014	-	80,091	-	-	121,072	220,973	204,120	-	16,853	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(l)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST-BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
240	2027	Vulnerability and Exposure Managem	Software(Intangible)	Security	This project will enhance the Company's Vulnerability Management program by implementing a cohesive suite of technologies focused on Vulnerability Management. These technologies will include minimally the following capabilities: vulnerability management, web application static and dynamic analysis, and attack surface management. Vulnerability Management is a critical process for identifying, assessing, and mitigating security weaknesses within an organization's IT infrastructure. This proactive approach involves continuous monitoring and evaluation of systems to detect vulnerabilities that could be exploited by cyber threats. By prioritizing vulnerabilities based on risk, cost, and potential impact, organizations can effectively allocate resources to address the most critical issues first. Implementing a robust Vulnerability Management program not only enhances the security posture of the organization but also ensures compliance with industry regulations and standards, thereby reducing the risk of data breaches, malware infections, ransomware, and other cyber threats. This Vulnerability Management program supports business continuity and protects sensitive information and systems, making it an essential component of any comprehensive cybersecurity strategy. The Company's current Vulnerability Management program relies on multiple disparate tools to perform core activities such as scanning, analysis, and remediation tracking. This multi-tool approach can create inefficiencies, increase the likelihood of data gaps, and require additional effort from users to correlate and interpret information across platforms. The use of several systems to manage vulnerabilities can lead to inconsistent workflows, duplicated efforts, and reduced coordination between teams. Streamlining the tool set or improving integration between existing solutions would enhance operational efficiency and support a more cohesive vulnerability management process. This project creates value for the Company by (1) enhancing the efficiency and effectiveness of the Vulnerability Management program through improved integration and reduced reliance on multiple standalone tools; and (2) supporting risk-based decision-making by enabling more consistent identification, prioritization, and remediation of vulnerabilities. These improvements will reduce operational overhead, minimize security exposure, and help ensure continued alignment with industry regulations and cybersecurity frameworks. The project scope includes evaluating and implementing a new vulnerability solution. The scope also includes enablement of active scanning with the new solution, consolidating data sources, and improving cross-platform visibility. Alternatives considered include: (1) continuing with the current multi-tool Vulnerability Management program. This option was not selected as it perpetuates inefficiencies, inconsistent workflows, and limited visibility across platforms; (2) increasing manual efforts to correlate and manage data between existing tools. This alternative was not chosen due to the high resource demands and increased risk of human error, which may further delay remediation timelines; (3) procurement of a new, cloud-based consolidated vulnerability management platform. This option was chosen as it allows the Company to enhance vulnerability data, threat intelligence, and process efficiencies within the current environment to deliver immediate value with high confidence in the vulnerability data that is being provided.	2027-01-15	2027-11-30	-1.00	1,418,998	290,800	ROM	939,945	764,803	-	72,500	23,184	-	79,458	183,204	156,240	-	26,964	-	-	-
241	2027	Workstation Temporary Administrativ	Software(Intangible)	Security	This project will implement controls that will allow local least administrative access to workstations on a time limited basis. Non-IT and Security resources will be able to request this access. Temporary administrative access to workstations is required to support some application installations, local system configuration, or to troubleshoot workstation issues. Currently, administrative access is only allowed on employee workstations for authorized users that is granted by a manual process. The current process allows the authorized user to have access to everything on the employee workstation which allows for human error. The process is resource intensive and requires manual removal of access. Cyber Security and Information Technology (IT) teams do not have controls in place to restrict the usage of local administrative accounts or monitoring capabilities to detect misuse without human intervention. The current state creates an environment for misuse where broad admin access could be leveraged for data breaches and ransomware. A successful attack would impact the Company's ability to serve our customers. This project creates value for the Company by: (1) reducing risk by eliminating over 1,000 local administrative accounts; (2) adding the ability to implement security controls and restrictions on local administrative functions; (3) increasing productivity by reducing the time and resources needed to provision, manage, and audit local accounts for security compliance; (4) adding the ability to provide administrative access for a specific and limited duration of time, thereby reducing cyber security risk of workstation compromise. This project will implement a platform that can enforce security controls and audit the security compliance of local administrative accounts for Company workstations. The features of this platform include: (1) the ability to give administrator access for a specific duration of time; (2) enable applications to automatically run in a privileged state; (3) the ability to remotely change the administrator password; and (4) generate a single-use administrator password. Alternatives considered include: (1) accepting the risk of using local administrators that are not managed centrally for end point administration. This alternative was not chosen because the usage of these accounts doesn't follow company standards for software provisioning and introduces unsupported software versions and vulnerabilities into the environment; (2) continuing the existing practice of manual oversight to grant local administrative access which does not eliminate the risk of misuse of administrator access. This alternative was not selected because it doesn't follow company standards for software provisioning and introduces unsupported software versions and vulnerabilities into the environment; (3) developing a platform for administrative account access internally. This alternative was not chosen due to the time frame it would take internal resources to develop and maintain the solution at the same level of quality and feature parity as a commercial product; and (4) implement a cloud platform specifically developed for managing local administrative accounts. This option was chosen because of the features designed for managing local administrative accounts will reduce the risk of misuse of administrative credentials within the Company.	2027-02-01	2027-07-31	-1.00	995,035	21,400	ROM	659,111	534,083	-	44,298	-	-	80,730	13,462	-	-	13,462	-	-	-
242	2027	20% ROM Adjustment - Security	Software(Intangible)	Security	This is for the 20% ROM Adjustment for Security projects.							(1,232,297)	(1,057,080)	-	(46,002)	(25,834)	-	(93,381)	-	-	-	-	-	-	-
243	SUBTOTAL	2027 Security										14,391,114	6,617,446	4,855,114	1,575,533	1,145,706	-	1,197,345	1,752,630	868,574	27,326	397,666	59,998	-	(27)
244	TOTAL	2027										56,553,338	12,889,080	19,844,841	9,930,164	8,796,983	-	5,092,269	12,669,574	1,231,807	471,746	9,205,368	5,918,574	-	123,078
245	2028	Application Currency-Corporate-O&A	Software(Intangible)	Corporate	The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that will require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software, and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2028-01-01	2028-12-31	-1.00	-	43,163		-	-	-	-	-	-	-	27,193	-	-	27,193	-	-	-
246	2028	Asset Accounting Tax Upgrade	Software(Intangible)	Corporate	The project will upgrade the Company's current on-premise accounting asset management tax software to the SaaS version as required by the vendor ensuring continued support of a critical financial application and providing new functionality. In 2025, standard vendor support ends for the current on-premise PowerTax software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the tax fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility. This project creates value for the Company by ensuring compliance with regulated and financial accounting within the tax fixed asset sub-ledger. In addition, the project adds value by: (1) moving to a SaaS solution in order stay supported; and (2) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) evaluating current vendor/product solutions with market leaders; and (2) upgrading the vendor software from the current version to the newer SaaS version; or replacing it. Alternatives considered include: (1) evaluating SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features such as centralized tax error processing. (2) evaluating other software options. This option may not provide appropriate regulatory reporting and other needed improvements and introduces several complexities and costs: Integration Challenges as PowerPlan modules are designed to work seamlessly together and data synch, mapping, and real-time updates may not be as robust as with native modules; Loss of Automation and Efficiency as there may be manual data transfers, duplicate entries and reduced automation increasing labor costs and risk of mistakes; Higher IT and Support Costs as maintaining two asset accounting systems means higher IT overhead with upgrades, troubleshooting, and user training; Reduced Data Integrity and Security as splitting tax data between systems can create gaps in data integrity, audit trails, and security controls; and Limited Vendor Accountability as when issues arise, vendors may point to integration boundaries making troubleshooting and issue resolution slower and more complicated. (3) moving entire PowerPlan suite, which includes PowerTax, to their cloud option. This option would be expensive from a licensing and integration build perspective, has an unclear timeline, and would remove the opportunity for direct database control. (4) waiting until a future upgrade cycle. This option introduces technical risk and potential financial processing risk. (5) upgrading to a newer version of the current solution. This is the preferred option as it will provide more frequent software upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.	2027-02-01	2028-02-28	-1.00	-	400,191	ROM	-	-	-	-	-	-	-	36,017	-	-	19,187	16,830	-	-
247	2028	Asset Accounting Upgrade 2027-202	Software(Intangible)	Corporate	The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application. Standard vendor support will be ending for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complex testing activities and too many version increases at any one time. This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted. The project scope includes: (1) evaluating current vendor/product solution with market leaders; and (2) upgrading the vendor software from the current version to a newer version. Alternatives considered include: (1) Evaluated SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) Evaluated other software options. This option would introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements; (3) Address cloud possibilities. This option is expensive and has an unclear timeline roadmap; (4) wait until a future upgrade cycle. This option introduces technical risk; (5) Upgrading to a newer version of current solution. This is the preferred option as it will provide more frequent software upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.	2027-02-01	2028-02-28	-1.00	-	671,749	ROM	-	-	-	-	-	-	-	45,021	-	-	11,361	33,661	-	-
248	2028	Enterprise Risk Management	Software(Intangible)	Corporate	The project will implement software to streamline Enterprise Risk Management (ERM) processes, improve efficiency, provide risk identification and repository tools, and deliver real-time risk data. The Enterprise Risk Team (ERT) collaborates with Risk Owners (ROs) annually to identify new risks, update existing ones, quantify impacts and likelihoods, document mitigation plans, identify trends, and formulate risk tolerance metrics. This process involves iterative exchanges between ERT and ROs to align on content. This effort culminates in multiple risk maps presented annually to senior management and the Board of Directors (BoD). The manual Enterprise Risk Management (ERM) process is intensive and time-consuming, creating risks of human error that can inaccurately quantify risks, introduce data anomalies, and create version tracking issues. The current process results in inefficient use of time by risk analysts and risk owners, limits the breadth of analysis, and affects the Company's ability to promptly identify, analyze, and communicate risks to senior leaders, potentially causing delays in responding to emerging risks. Due to its lengthy nature, the manual process is conducted only once a year but needs to be performed more frequently for proactive enterprise risk management. Utility industry peers use software to more effectively manage enterprise risk management programs. This project creates value for the Company by: (1) providing real-time risk information to stakeholders including the risk team, risk owners, senior management, and the Board of Directors (BoD); (2) supporting proactive risk management; (3) establishing a centralized repository for risk identification, management, and mitigation plans; (4) reducing waste through simplified processes; and (5) enhancing efficiency for risk owners and analysts. The project scope includes: (1) creating risk analysis templates and tools for automated reporting; (2) establishing automated workflows to perform risk updates; (3) configuring dynamic templates that prompt the risk owners based on prior selections; (4) organizing risk assessments through an online and searchable data repository; (5) creating new reports and executive dashboards; (6) migrating data; and (7) setting record retention rules. Alternatives considered include: (1) Continuing to use the current manual processes. This alternative was not chosen due to inefficiencies, poor quality results, and limited frequency of risk reviews. (2) Building a custom internal enterprise risk solution. This alternative was not selected because it does not incorporate best practices available in risk management software provided by industry leaders. (3) Implementing a software solution from a leading enterprise risk solution vendor. Although this introduces new license and ongoing support costs, it is preferred since it incorporates industry best practices, ensures application reliability, security, stability through vendor support, and provides innovation and insights via risk information reporting through management dashboards. Additionally, it aligns the Company with utility industry peer practices for more effective enterprise risk management.	2027-07-01	2028-07-03	-1.00	184,200	80,666	ROM	122,014	-	-	42,526	79,488	-	-	26,121	-	-	11,946	14,175	-	-
249	2028	HR Support Pack and Business Soft	Software(Intangible)	Corporate	The Human Resources (HR) Support Pack and Business Software Inc (BSI) upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll. This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company. xAlternatives considered include: (1) not upgrading to the current support packs, which results in noncompliance with financial rules and regulations and inaccurate payroll. (2) there is no economical cloud solution, so this option was not entertained. (3) the Company decided the best alternative is to apply the appropriate support pack upgrades. This option is preferred because it enables the Company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.	2028-02-06	2028-12-29	0.00	-	665,132		-	-	-	-	-	-	-	419,033	-	-	63,727	355,306	-	-
250	2028	Product Family Enhancements-Corp	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2028-01-01	2028-12-31	-1.00	1,031,882	74,206		683,519	82,215	1,957	163,025	381,391	-	54,931	46,750	15,825	39	7,431	23,455	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(l)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
251	2028	Product Family Enhancements-Corp	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Finance and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	-	353,192		-	-	-	-	-	-	-	222,511	186	-	67,010	155,315	-	-
252	2028	20% ROM Adjustment - Corporate	Software(Intangible)	Corporate	This is for the 20% ROM Adjustment for IT projects.							(34,470)	(8,404)	-	-	(25,998)	-	-	-	-	-	-	-	-	-
253	**SUBTOTAL**	**2028 Corporate**										**855,533**	**82,215**	**1,957**	**205,551**	**460,879**	-	**54,931**	**822,647**	**16,011**	**39**	**207,555**	**598,742**	-	-
254	2028	Application Currency-Customer-O&M	Software(Intangible)	Customer	The Customer initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Customer digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Customer are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2028-12-31	-1.00	-	57,170		-	-	-	-	-	-	-	36,017	-	-	36,017	-	-	-
255	2028	Energy Assistance Enhancements ar	Software(Intangible)	Customer	The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy (CARE) project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interfaces and updates to SAP to process various requests. Upcoming modifications will be identified following an ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services (DHHS) and Michigan Public Service Commission (MPSC) to prioritize the list of changes. Each grant year, DHHS and MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track active CARE customers, and how they will administer the Michigan Energy Assistance Program (MEAP) benefits through bill credits and arrears forgiveness. The criteria changes significantly each year; therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requests are not fulfilled, the Company is at risk of losing state Low Income Energy Assistance Fund (LEAF) funds to assist low-income customers with paying their energy bills, thereby increasing the customers risk of shutoff for non-payment. In addition, our energy assistance programs function within all software platforms in the company which consistently need enhancements and updates. The project will provide the following value: (1) complete modifications to internal SAP application and Agency Portal to receive LEAF funding, which can be used to provide customers the bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LEAF funding; and (3) complete modifications to customer facing platforms. The project scope includes: (1) updating the enrollment and status process; (2) allowing for flat monthly bills; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and Michigan Public Service Commission; (6) updating CARE dunning process; and (7) updating the assistance portal (CE PASS) functionality to enhance Agency Self-Service. Alternatives considered include: (1) continue with current process. This alternative was not chosen because it would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third-party organization. This alternative was not selected because it would remove ownership and viability into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. This option was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems such as SAP, a large internal system that supports broad areas of the business, and the Agency Portal, an internally developed web application, therefore a single cloud or third-party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.	2026-01-01	2028-12-31	0.00	-	292,962		-	-	-	-	-	-	-	184,566	-	-	105,826	78,740	-	-
256	2028	Product Family Enhancements-Cust	Software(Intangible)	Customer	The Customer initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	2,283,817	544,183		1,512,800	30,191	5,952	331,928	998,429	-	146,300	342,835	3,113	-	47,387	291,827	-	508
257	2028	Product Family Enhancements-Cust	Software(Intangible)	Customer	The Customer initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	-	234,667		-	-	-	-	-	-	-	147,840	-	-	45,380	102,460	-	-
258	2028	Rate Change Maintenance	Software(Intangible)	Customer	The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements. For the Company to continue to meet and comply with certain MPSC requirements and to enable it to update its rates when rate changes are approved, there is a need to make periodic updates/modifications to existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers. The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that includes new surcharges, price changes, and energy efficiency programs. The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Company's back-end system for more efficient rate changes. Alternative considered include: (1) a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and the time it would take for testing of this model; and (2) Instead, the Company chose to leverage onshore resources to plan, coordinate, and execute the rate changes. This option was selected as it supports the Company's operation model for rate changes.	2026-01-01	2028-12-31	0.00	-	298,844		-	-	-	-	-	-	-	188,272	-	-	13,783	174,489	-	-
259	**SUBTOTAL**	**2028 Customer**										**1,512,800**	**30,191**	**5,952**	**331,928**	**998,429**	-	**146,300**	**809,531**	**3,113**	-	**248,394**	**647,515**	-	**508**
260	2028	Advanced Distribution Management I	Software(Intangible)	Electric	The Advanced Distribution Management System Upgrade (ADMS) project will enhance operator experience, simplify maintenance, and provide more powerful and flexible system functionalities. These include advancements in Fault Location, Isolation, and Service Restoration (FLISR), waste elimination within Maestro, the introduction of independent line sensors, a redesign of temporary conditions, and will incorporate operational views of schematics. The project will also be replacing the outdated hardware. The current ADMS lacks several critical features and improvements that are essential for enhancing operator experience, system maintenance, fault detection, and response capabilities. The existing system struggles with: (1) the current FLISR functionality does not adequately support complex protection requirements and manual switching steps, leading to inefficiencies and potential errors; (2) operators face challenges with passthrough edits and managing conflicts related to devices with tags or temporary conditions, resulting in frequent system reloads and inaccuracies in the as-operated system; (3) the temporary conditions subsystem is cumbersome to use, hindering efficient operations and the ability to support schedule automation and; (4) the current schematic tools do not provide operational views or the ability to save and share views, limiting situational awareness and usability for operators. These gaps result in operational inefficiencies, increased maintenance efforts, and reduced effectiveness in fault management and system operations. Addressing these issues is crucial for improving the overall functionality, usability, and maintenance of the Distribution Management System. (5) The Company runs the risk of increased failure if it does not regularly refresh the infrastructure. The project will add value by: (1) improving the user interface and overall experience of the operations, (2) increasing the flexibility and configurability of FLISR, allowing for better support of complex protection requirements and improving solutions for manual switching steps, (3) enhancing the usability of schematics, providing operational views and the ability to save and share views for better situational awareness, (4) developing advanced switch order functionality to support more robust and efficient operations, (5) allowing ADMS to pull real time network model from GIS Utility Network and (6) improving stability and availability of business-critical applications by proactively replacing hardware before it fails. The scope of the project includes: (1) replacing ADMS hardware, (2) upgrading the existing ADMS platform to the latest packaged version, (3) adding in the feature improvements for Temporary Condition Redesign, Maestro Conflict Resolutions, Independent Line Sensors, FLISR and Schematics, (4) implementing new extraction tool, (5) testing the new functionality in various possible scenarios, and (6) communicating and training users on the new functionality. Alternatives considered include: (1) using outdated equipment and current version of ADMS. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact the Company's ability to respond effectively in storm situations. (2) Moving to a cloud version of ADMS. This option was not selected as the current public cloud platforms do not offer the high security environment required for the ADMS application. Consequently, the vendor platform was not built for cloud environments. (3) Replacing the hardware and upgrading ADMS. This option was selected to alleviate the above concerns.	2026-03-02	2027-11-11	-1.00	11,035,811	892,993	ROM	-	-	-	-	-	-	-	40,000	40,000	-	-	-	-	-
261	2028	Application Currency-Electric-O&M	Software(Intangible)	Electric	The Electric/Generation/Renewables Engineering and Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric/Generation/Renewables Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Electric/Generation/Renewables Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2028-12-31	-1.00	-	177,913		-	-	-	-	-	-	-	177,913	-	-	177,913	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
262	2028	Electric Geographic Information Syst	Software(Intangible)	Electric	This project will replace the existing design software for Electric Low Voltage Distribution (LVD) with a new solution that will be fully integrated to the ESRI (Environmental Systems Research Institute) GIS (Geographic Information System) platform which is already in use by the Company. This new solution will leverage GIS asset data to generate engineering designs. This will allow the Electric teams to have a single source and format to view asset data, construction drawings and redlines in both the back office and field. This change will further enable improvements to the mobile platform in quality of data that is used by the closeout team. This will also reduce the back and posting effort by using the native GIS data format; improving data quality by reducing the re-keying of data. The current design software creates waste in three areas for many teams within Electric including Low Voltage Distribution (LVD) Engineering, Field Leaders, and Customer Energy Management (CEM) Service Designers. (1) The current software does not support the native GIS data format and will not support future enabling work management needs. This causes waste and room for error by having to redraw designs in GIS that have already been created and prevents optimization of the work process. (2) It is not able to integrate to SAP to automatically order materials based on the design. (3) The current software lacks needed mobile functionality due to its lack of support for the native GIS format. The designs are not georeferenced to the exact location and can't fully utilize redlining capability which causes a significant impact to data quality and crew performance. This project will add value to the Company and its employees through: (1) eliminating the need to duplicate all design work so it is in both the design system and GIS; (2) enabling mobile editing and redlining on the design in GIS; (3) enabled integration to SAP; and (4) utilizing the capabilities of the next generation GIS platform that will be delivered through an in-progress business case. The project scope includes: (1) installing a new solution that will integrate to GIS; (2) utilizing GIS geospatial and asset information data and the GIS platform for generating Electric LVD engineering designs; (3) integrating to and from SAP to automate Compatible and Mass Unit material ordering capability; (4) installing new and upgrading existing geospatial platform infrastructure to support additional users (Electric LVD designers, Field Leaders, Planners, Schedulers, etc) of GIS; (5) integrating to ProjectWise (engineering content management system); (6) configuring mobile toolset; (7) re-engineering the existing GIS data model to handle asset life cycle; and (8) configuration for new ArcGIS services.	2025-09-09	2029-02-22	-0.47	6,241,626	659,758		1,109,865	-	-	775,167	-	-	334,698	136,794	-	-	136,794	-	-	-
263	2028	Electric GIS Utility Network Transfor	Software(Intangible)	Electric	This project will transform the Company's current Geographic Information System (GIS) platform to the Environmental Systems Research Institute (ESRI) Utility Network Model and establish a unified high voltage distribution (HVD), low voltage distribution (LVD), and substations data model. This transformation aims to optimize core engineering and operational processes, technologies, and data. The Company's GIS for electric records is expanding as an authoritative source for asset connectivity, location and health information. However, growing business requirements for advanced analytics and regulatory mandates necessitate more granular geospatial insights. Existing functionality does not meet business partner needs, and GIS data is refreshed in batch mode once a day, leading to mismatches with real-time systems. Managing HVD and LVD data in different models remains challenging. The Company's past implementation of ESRI's GIS for Electric, version 10.8.1, will be unsupported after March 1, 2028. Critical third-party solutions supporting key editing and business functionality are also ending support without upgrade options, posing risks for security updates. ESRI's development focus is shifting to the ArcGIS Utility Network Management extension, ArcGIS Enterprise, and ArcGIS Pro. The vendor's development team has reached the limits of ArcMap and the geometric network's capabilities and will no longer build additional functionality. Future development and enhancements are focused on the next-generation technologies of the Utility Network and ArcGIS Pro. ESRI utility solution partners are also moving their product lines away from the geometric network, soon supporting only the Utility Network. The project creates value for the Company by: (1) mitigating risks associated with product support end of life; (2) enabling detailed asset management and location based analytics to bring clearer understandings around the assets that support energy delivery; (3) increasing productivity through use of shortcuts, templates, and streamlined workflows within the software; (4) providing extensive, out-of-the-box tracing tools; (5) providing 3D visualization functionality; (6) enabling users with editing tools, giving them guidance at every step of the process for developing workflows and enforcing stronger data integrity; (7) viewing the up to date network in a map or schematic diagram and be able to quickly toggle back and forth between them; and (8) enabling archiving and historical versioning to view the state of the electric network over time. All of these capabilities will result in greater insight and efficiency that improves the safety and delivery to customers of Michigan. The Utility Network enables implementation of third-party tools that will allow us to keep the operational model more up to date as circuits with temp conditions and/or control tags can be imported as needed. The project scope includes: (1) upgrading all database, web, and application servers to supported Windows version; (2) upgrading end user application from ArcGIS Desktop to ArcGIS Pro; (3) migrating and converting LVD and HVD GIS data from geometric network data schema to the Utility Network, iteratively publishing data to new model for consumption; (4) reconfiguring electric applications that are integrated with GIS or that consume GIS data; and (5) creating substation asset model. Alternatives considered include: (1) Continue to use geometric network. This alternative was not selected because the architecture is at the end of its life. Additionally, dependent third-party solutions are moving away from the geometric network, making it unsustainable for continued use. (2) Moving to Utility Network and migrating to a supported platform. This alternative was chosen to enable the Company to leverage a cloud-based solution and provide options for utilizing third-party solutions.	2027-07-01	2029-12-04	-1.00	20,408,033	5,007,911	ROM	9,980,290	45,000	-	1,867,227	6,507,208	-	1,560,855	1,496,636	50,000	-	369,135	910,112	-	167,389
264	2028	HVD Supervisory Control and Data A	Software(Intangible)	Electric	The Electric HVD Monitoring System Upgrade project upgrades the software (every 2 years) and hardware components (every 4 years) of HVD SCADA system. This will include the upgrade of the underlying operating systems and database platforms that the software resides on as needed to maintain vendor support. This system is used to monitor and control generation and high voltage distribution voltage circuits. This project will add additional features and enhancements to HVD Monarch, the Company's HVD SCADA platform that improves efficiency and reliability. Running on an older version of the HVD hold have potential impacts on the reliability and resiliency of the low voltage distribution (LVD) system as well as the HVD system, as distribution reliability metrics depend upon HVD system availability. Maintaining an older version of the software and hardware creates risks associated with vendor responsiveness in addressing problems, as they arise. It will also take more effort to support any upgrades in the future because of difficulties resulting from longer durations between upgrade efforts. If upgrades are delayed, additional full-time resources will be required for the year upgrades occur to address upgrade complexities. Upgrading the HVD SCADA software and hardware adds value to the Company by ensuring that problems are promptly addressed when they occur. Additionally, the upgrade includes enhancements and fixes to the core product that support the resiliency of electric delivery, ensuring that customers are receiving the energy they need when they need it. Also, the distribution system depends on availability of the HVD system, staying current with the solution provider upgrades is critical to the resiliency of both systems. The scope of this project is an upgrade to the HVD SCADA software and hardware, which encompasses the following: (1) upgrading the application software; (2) upgrading the underlying operating systems and database platforms; (3) upgrading the underlying application hardware; (4) implementing new functionality for improved value to the Company; (5) making necessary configuration changes; and (5) updating documentation related to the integration changes. Alternative considered include: (1) Defer the biennial upgrade of the SCADA application and its hardware. The Company targets SCADA biennial application upgrades to stay within two versions of the current application due to maintain application stability and cyber security, given the critical nature of the SCADA system. This alternative was not chosen due to increased security risk and need for vendor support of the application. Additionally, the hardware is already past the end of its useful life and has been moved over to a 3rd party warranty provider. (2) Alternative Vendor solution. This option was not chosen because the move from our current vendor would be time consuming and costly. It could also introduce instability as any alternative solutions have not been proven operationally. (3) Do nothing. This option was not chosen due to the critical nature of these systems and the potential operational risks associated with operating on an unsupported solution. (4) Move to cloud. This option was not chosen as CE's internal security requirement is to host control systems on premise. (5) The option chosen is to complete the upgrade project with associated hardware and software necessary to complete the project that will deliver new functionality for improved value.	2026-01-01	2029-12-04	-1.00	3,400,290	257,005	ROM	1,780,870	525,000	760,000	74,500	300,000	-	121,370	170,500	-	-	160,500	-	-	10,000
265	2028	Integrated Energy Management Platf	Software(Intangible)	Electric	This project will reduce data center assets running PCI Energy Solutions by migrating into vendor cloud hosting solution. This will optimize vendor support, reduce operational costs (upgrades, server maintenance) and allow the Company to leverage new cloud capabilities. PCI Energy Solutions (PCI) provides software the Company uses to fulfill the Federal Energy Regulatory Commission (FERC) requirement of communicating unit availability to the Regional Transmission Operator and become more efficient at buying and selling electricity in the wholesale market. Due to the solution being Company hosted, the Company is not able to leverage benefits of the functionality in the vendor's cloud hosting solution (Software as a Service (SaaS)). The complex nature of the solution requires serious IT and business support teams to monitor, maintain and upgrade the system. Due to the critical nature of the application, the Company is looking to the SaaS hosting to benefit from the uptime SLA of 99.95% and the streamlined operational support for faster issue resolution. This project creates value for the Company by: (1) utilizing the vendor's SaaS environment which provides efficiencies for timely operational support. Currently, as an example, IT sends PCI a database copy so they can replicate the Company's environment in the vendor's system. This leads to waste of resources, time and increased support costs. (2) Freeing up resources for more value add work. As the Company optimized the organization, it is very important to reduce waste and work on the most valuable items; (3) reducing Oracle footprint; (4) reducing IT labor support costs; (5) reducing ongoing networking equipment refreshment and upgrade costs. The project scope includes: (1) planning and executing the data migration; (2) designing and configuring new and existing vendor SaaS components; (3) implementing integrations to COTS (Commercial Off-The-Shelf) and custom systems; (4) testing; (5) educating and increasing the skills of the employees to leverage the new vendor SaaS services; (6) decommissioning old infrastructure. Alternatives considered include: (1) continue to use the Company hosted installation of PCI. This alternative was not chosen due to the significant waste involved in maintaining the system, the inability to leverage Cloud functionality, and the failure to decrease the reliance on Oracle servers. (2) Move to a different energy market platform. This alternative was not selected because the different platform would have lesser options and would not be able to utilize PCI's bid to build process. (3) Move to the vendor SaaS. This alternative was selected as the Company will utilize the latest technology and optimize operational support.	2027-05-02	2028-03-16	-1.00	4,329,636	1,662,202	ROM	135,429	-	-	94,588	-	-	40,841	50,932	-	-	50,932	-	-	-
266	2028	Product Family Enhancements-Elect	Software(Intangible)	Electric	The Electric/Generation/Renewables Engineering and Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric/Generation/Renewables Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric/Generation/Renewables Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric/Generation/Renewables Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	719,345	188,564		719,345	20,000	-	185,588	453,062	-	60,695	188,564	-	-	34,331	154,233	-	-
267	2028	Product Family Enhancements-Elect	Software(Intangible)	Electric	The Electric/Generation/Renewables Engineering and Operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric/Generation/Renewables Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric/Generation/Renewables Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric/Generation/Renewables Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	-	120,493		-	-	-	-	-	-	-	120,493	2,280	-	52,124	66,090	-	-
268	2028	20% ROM Adjustment - Electric	Software(Intangible)	Electric	This is for the 20% ROM Adjustment for IT projects.							(2,379,318)	(114,000)	(152,000)	(407,263)	(1,361,442)	-	(344,613)	-	-	-	-	-	-	-
269	**SUBTOTAL**	**2028 Electric**										**13,725,799**	**590,000**	**760,000**	**2,997,970**	**7,260,270**	-	**2,118,458**	**2,361,632**	**52,280**	-	**961,729**	**1,130,435**	-	**177,389**
270	2028	Application Currency-Electric & Gas	Software(Intangible)	Electric & Gas Shared	The Electric and Gas Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor support/renewal, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2028-12-31	-1.00	-	731,863		-	-	-	-	-	-	-	461,074	-	-	420,680	40,393	-	-

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Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
271	2028	Application Currency-Operational Te	Software(Intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2028-12-31	-1.00	-	208,646		-	-	-	-	-	-	-	130,187	-	-	130,187	-	-	-
272	2028	Product Family Enhancements-Elect	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric and Gas operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	1,826,301	307,743		1,209,742	-	29,699	217,220	887,934	-	74,889	193,678	-	-	46,883	146,929	-	67
273	2028	Product Family Enhancements-Elect	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	-	566,033		-	-	-	-	-	-	-	356,601	15	-	47,634	308,910	-	41
274	**SUBTOTAL**	**2028 Electric & Gas Shared**										**1,209,742**	**-**	**29,699**	**217,220**	**887,934**	**-**	**74,889**	**1,141,740**	**15**	**-**	**645,304**	**496,232**	**-**	**108**
275	2028	ARP-Radio	Network	IT/Digital Foundation	This project will refresh hardware to include: 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices, vehicle consoles in service trucks, other communications equipment, and associated test equipment. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 10-year lifecycle basis. Cellular modems are refreshed on a five-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle. 800MHz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customers service and critical infrastructure. Company radio and cellular systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing or becoming obsolete. The refresh of this equipment in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety. This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure. The project scope consists of: (1) scheduled replacement of radios, modems, consoles; and (2) installing additional radios, modems, and console assets to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters and systems. The alternatives considered include: (1) Replacing the existing units with new units from other radio and modem manufacturers; (2) Purchasing new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.	2026-01-01	2028-12-31	-1.00	1,735,113	84,246		908,852	-	660,918	20,114	-	7,432	53,075	-	-	50,432	1,383	1,260	-	-
276	2028	ARP-Collaboration	New Computers / Hardware	IT/Digital Foundation	This project will replace the Company's obsolete or out-of date audio, visual, telephony and other communication collaborative tools and equipment. When collaboration assets used to support customer interactions and business operations are obsolete or out-of-date, they are more difficult to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project creates value by: (1) ensuring the stability and reliability of the Company's audio, visual, telephony, and other communications systems; and (2) migrating to new collaboration assets. The project scope consists of: (1) replacing aging collaboration assets; and (2) installing new collaboration assets to meet evolving business requirements. The alternatives considered include: (1) continuing to operate collaboration assets beyond a five-year refresh cycle, or (2) refreshing collaboration assets based on a five-year refresh cycle while evaluating the health of the asset and evolving business requirements. The alternative to operate the collaboration assets beyond a five-year refresh cycle was not selected due to the risk of asset failures would cause stability and reliability issues for employees supporting our customers, as vendors do not provide extended support after five years. The Company chose to refresh the collaboration assets based on a five-year refresh cycle and evaluate the health of the asset and evolving business requirements to reduce the risk of impacting the productivity of employees supporting our customers.	2026-01-01	2028-12-31	-1.00	2,639,319	207,361		1,748,285	-	1,595,255	34,854	107,971	-	10,204	130,637	-	-	42,437	88,200	-	-
277	2028	ARP-Field Device Asset Management	New Computers / Hardware	IT/Digital Foundation	This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility. When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices before they fail; and (2) allowing field workers to complete their job tasks. The project scope consists of replacing field device assets according to the four-year refresh cycle. Alternatives considered include: (1) using outdated equipment. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact meter readers' ability to complete job tasks. It would also complicate the Company's efforts to meet the MPSC's meter reading factor and consecutive estimated targets, and it could cause applications to run poorly or stop functioning; (2) The second alternative considered was to replace the hardware. The Company selected this option to alleviate the above concerns.	2026-01-01	2028-12-31	-1.00	4,765,207	3,556		3,156,473	-	3,075,848	58,686	-	-	21,939	2,240	-	1,922	144	174	-	-
278	2028	ARP-Operational Technology Suppo	New Computers / Hardware	IT/Digital Foundation	The Asset Refresh Program (ARP)-Operational Technology (OT) Support Common project will replace dated and obsolete servers shared by Electric and Gas on a rotating five-year refresh schedule. When Operational Technology Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure. The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure.	2026-01-01	2028-12-31	-1.00	2,599,980	254,552		1,722,214	-	1,656,000	48,196	-	-	18,017	160,368	-	151,200	9,168	-	-	-
279	2028	ARP-Operational Technology Suppo	New Computers / Hardware	IT/Digital Foundation	The Asset Refresh Program (ARP)-Operational Technology (OT) Support Electric project will replace dated and obsolete servers on a rotating five-year refresh schedule. When Operational Technology Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure. The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Electric SCADA.	2026-01-01	2028-12-31	-1.00	293,972	52,186		293,972	-	224,000	50,932	-	-	19,040	52,186	-	42,000	10,186	-	-	-
280	2028	ARP-Printer Asset Management (PAI	New Computers / Hardware	IT/Digital Foundation	This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one. When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications. The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. This does not mean that all printers are replaced after five years merely that printers are assessed on a five-year cycle for possible replacement. The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years would require the printers to be assessed monthly to ensure they are not run to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.	2026-01-01	2028-12-31	-1.00	233,292	8,454		154,533	-	150,930	2,622	-	-	980	5,326	-	83	5,064	162	-	16
281	2028	ARP-Server and Storage	New Computers / Hardware	IT/Digital Foundation	This project will replace or augment server and storage infrastructure for the Company. When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be more challenging to keep current with Security updates. The Company also runs the risk of failure of these assets impacting customer interactions and business operations if it does not adhere to a regular five to seven-year refresh cycle. This project creates value for the Company through: (1) improved stability and availability of business-critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use. The scope of this program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements. The alternatives considered were to: (1) purchase extended maintenance; (2) move some of these assets to the cloud with the Digital -Hybrid Cloud and Data Center Migration project or; (3) replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option.	2026-01-01	2028-12-31	-1.00	1,174,955	14,000		778,290	-	635,748	95,684	-	-	46,858	8,820	-	-	8,820	-	-	-
282	2028	ARP-Workstation Asset Management	New Computers / Hardware	IT/Digital Foundation	This project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates. When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks. The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. The alternatives considered were to purchase extended maintenance, move some of these assets to the cloud with the Digital -Hybrid Cloud and Data Center Migration project, or to replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven year cycle as it is the most cost-effective option.	2026-01-01	2028-12-31	-1.00	11,084,879	101,362		7,342,624	-	7,077,210	119,123	104,494	-	41,797	63,858	-	14,413	14,060	1,518	-	33,867

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST-BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
283	2028	Application Currency-IT-Digital Foun	Software(Intangible)	IT-Digital Foundation	The Application Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms area are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2028-12-31	-1.00	-	387,430		-	-	-	-	-	-	-	231,481	-	-	231,481	-	-	-
284	2028	Application Currency-IT-Digital Foun	Software(Intangible)	IT-Digital Foundation	The Infrastructure Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Infrastructure Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Infrastructure Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2028-12-31	-1.00	-	38,590		-	-	-	-	-	-	-	24,312	-	-	24,312	-	-	-
285	2028	Enterprise Print & Scan Suite Upgrad	Software(Intangible)	IT-Digital Foundation	The projects intent is to upgrade the current Enterprise Print and Capture suite for improved data security and integration for the work from home business partner. The company currently maintains a print and capture suite that will have support ending in 2028. Only high-level security patches will be available after this date. The company maintains a fleet of servers that are scheduled to be upgraded. The lack of internal resources requires the company to continue to absorb increased costs to contract administrative personal. This project maintains cost savings achieved by eliminating wasteful print jobs and further enables productive, and flexible workforce for business partners working remotely. This project also ensures that the latest data transmission security requirements of are met by the solution. The project scope includes: (1) upgrading the current suite to the latest version; (3) training for company personal to administer the suite; (4) maintaining all workflows from the current system; (5) continue with remediation for security vulnerability risk. Alternatives considered: (1) migrating to cloud services. This alternative was not chosen at this time due to maturity levels found with subscription services. (2) other print-scan products. This alternative was not selected as it would required new print and scanning specific to another print-scan product. (3) Print-scan products that were less costs. This alternative was not selected, due to fewer capabilities offered than the current product, which would introduction inefficiencies in the current processes. (4) upgrade current product. This alternative was chosen due to lower overall cost of not requiring new hardware, maturity of current product, and providing same level of capabilities required to support current processes.	2026-03-01	2028-12-29	-1.00	287,654	63,102	ROM	190,542	-	-	32,088	141,091	-	17,363	39,754	-	-	12,338	27,416	-	-
286	2028	Enterprise Service Bus 2028-2029 U	Software(Intangible)	IT-Digital Foundation	This project will upgrade the current Enterprise Service Bus software versions in use at the Company. Newer ESB software versions offer improved integration with RestAPI services and applications. It is critical that this vital data tool or pathway, be more scalable, secure, and capable of integrating to a service-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of approximately $80,000 annually, this is just temporary coverage and serves only to delay the need for an upgrade. The value this project provides the Company includes: (1) cost avoidance to avoid extensive payments for extend support purposes; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies. The project scope includes implementing current version of all applications that are part of the ESB application, database version, and required database drivers. Alternatives considered included: (1) Accept the annual $80,000 extended maintenance cost. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meter management. The current implementation of the ESB platform was built with 5 years of growth in mind. This alternative was not chosen due to risk to Company operations, and the additional expense. (2) Replace the on-premise upgrade plan to implement a cloud-based solution. A cloud migration would also take longer to complete, which would put the Company at risk of falling outside of the current vendor support window for the products current version. (3) Upgrade the existing application. This option was selected because it best meets the Company needs for the near future by restoring vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.	2026-09-02	2029-09-21	-1.00	-	520,248	ROM	-	-	-	-	-	-	-	21,610	-	-	21,610	-	-	-
287	2028	ISIS Papyrus 2028 Upgrade	Software(Intangible)	IT-Digital Foundation	This project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The ISIS Papyrus application is critical to creating electronic and paper correspondence for customers, including bills and dunnings. It's imperative that customers retain unfettered access to their paper bills, dunning notices and other communications produced by ISIS. ISIS also makes customer bills available for online viewing through the website and mobile apps. Without the upgrade, vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity and security will be forthcoming. The upgrade will address these problems and challenges, as well as ensuring all other platform components comply with the Company's operational and security standards. The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors. The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications. Alternatives considered include: (1) delaying the upgrade and continuing to operate with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching. (2) The Company instead decided to upgrade to the current version. This alternative was chosen as it eliminates the risk of application instability and the inability to maintain cyber security patching.	2028-02-01	2028-10-01	-1.00	-	217,246	ROM	-	-	-	-	-	-	-	136,865	-	-	136,865	-	-	-
288	2028	Product Family Enhancements-Appli	Software(Intangible)	IT-Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	311,154	30,590		206,109	13,264	5,288	79,634	69,868	-	38,054	19,272	292	99	7,416	11,466	-	-
289	2028	Product Family Enhancements-Appli	Software(Intangible)	IT-Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	-	156,871		-	-	-	-	-	-	-	98,829	8,005	-	51,173	39,650	-	-
290	2028	Product Family Enhancements-Infras	Software(Intangible)	IT-Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software & hardware and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	402,938	130,035		266,906	2,124	29,401	116,147	67,114	-	52,120	81,922	2,069	59	21,138	58,657	-	-
291	2028	Product Family Enhancements-Infras	Software(Intangible)	IT-Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	-	73,464		-	-	-	-	-	-	-	46,295	279	10,410	6,733	28,873	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
292	2028	SAP Support Pack Upgrade 2028	Software(Intangible)	IT/Digital Foundation	The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for business partners. To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability. The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility. The scope of this project includes routine support pack upgrades to all SAP applications, which include: Customer Relationship Manager (CRM), Enterprise Portal, Process Orchestration (PO), Business Warehouse (BW), Business Objects (BOBJ), Data Services (DS), Governance, Solution Manager, Data Quality Manager (DQM), System Landscape Directory (SLD) and other related SAP applications. Alternatives considered include: (1) dividing the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) migrating to SAP S/4HANA. This option was not selected because SAP S/4HANA is a multi-year project that is not expected to be completed by year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3) Ultimately, the Company chose to balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.	2026-02-01	2026-10-31	-1.00	-	454,370		-	-	-	-	-	-	-	286,253	-	-	286,253	-	-	-
293	2028	20% ROM Adjustment - IT/Digital Fo	Software(Intangible)	IT/Digital Foundation	This is for the 20% ROM Adjustment for IT projects.							(38,359)	-	-	(6,417)	(28,738)	-	(5,479)	-	-	-	-	-	-	-
294	**SUBTOTAL**	**2028 IT/Digital Foundation**										**16,768,799**	**15,389**	**10,309,699**	**959,254**	**510,653**	**-**	**273,805**	**1,463,103**	**10,645**	**270,617**	**890,582**	**257,376**	**-**	**33,883**
295	2028	ARP-Cyber-Common	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions. When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades. The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warrant repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.	2026-01-01	2028-12-31	-1.00	749,224	12,130		392,443	-	364,355	19,735	1,002	-	7,351	7,642	-	1,575	6,067	-	-	-
296	2028	ARP-Cyber-Electric	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions for Electric. When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades. The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warrant repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.	2026-01-01	2028-12-31	-1.00	372,493	15,284		372,493	200	332,500	25,796	1,750	-	12,247	15,284	-	3,800	11,484	-	-	-
297	2028	ARP-Network-Common	Network	Security	This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks. When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks. The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices. The alternatives considered include: (1) continue to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.	2026-01-01	2028-12-31	-1.00	797,493	13,525		417,727	3,929	390,805	11,196	7,816	-	3,981	8,521	-	3,465	5,056	-	-	-
298	2028	ARP-Network-Electric	Network	Security	This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks for Electric. When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle. This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks. The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices. The alternatives considered include: (1) continue to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.	2026-01-01	2028-12-31	-1.00	106,117	1,784		106,117	400	99,184	3,349	1,984	-	1,200	1,784	-	500	1,284	-	-	-
299	2028	Critical Substation Upgrade	Network	Security	This project will implement enhanced security measures at the Company's critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time. With the enhanced security posture, Consumers Energy will be better positioned to mitigate malicious activity through real-time detection and increase the reliability of electric delivery to our customers. Today, Consumers Energy currently deems 16 substations as business critical to its electric system while an additional 34 substations fall under NERC-CIP compliance. Recent attacks to critical infrastructure have increased the likelihood of an adversary exploiting vulnerabilities at critical substation increasing the risk for large scale outages and customer impact. The Company's current security monitor tools are not allow us to detect, deter, or monitor potential threats on site. Without the ability to monitor these assets in real-time, the Company is vulnerable to an adversary causing destruction without knowledge of when or how the event took place. A phased implementation would allow the Company to systematically mitigate risk to assets deemed most vulnerable. The objective of this project is to implement enhanced security measures to better detect, deter, and respond to threats to the Company's electric substations in real-time. This enhanced security posture will align with other utilities that detect and operate substations and mitigate disruption to electric service while improving reliability. Enhanced Security measures that will need to be implemented include but are not limited to: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fence intrusion (which will be accomplished through camera systems); (6) subcontractor work of trenching poles, installing equipment etc.; (7) additional facility lighting; and (8) security equipment maintenance. Alternatives considered include: (1) maintaining the current security perimeter fencing and conducting routine inspections of the site. This alternative was not selected, as it does not provide the ability to prevent, detect, or respond to threats in real-time. (2) hiring contract security guards to patrol the sites. This alternative was not selected as ongoing O&M costs would be expensive; (3) outfitting sites with thermal cameras with built in analytics that would alarm for intrusions and subjects on the properties along with access control measures. This alternative was selected because of lower ongoing O&M costs and enhanced detection abilities.	2026-01-01	2026-12-31	-1.00	11,771,395	1,016,500	ROM	4,585,250	-	2,312,500	1,070,000	562,500	-	640,250	374,500	-	-	374,500	-	-	-
300	2028	20% ROM Adjustment - Security	Network	Security	This is for the 20% ROM Adjustment for Security projects.							(480,351)	-	(242,258)	(112,060)	(59,926)	-	(67,073)	-	-	-	-	-	-	-
301	2028	ARP-Physical Security	New Computers / Hardware	Security	The ARP-Physical Security, formerly known as Physical Security Asset Refresh, will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns. The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring alerts, compliance with regulations and guidelines, and faster responses to emergencies and incidents. This could result in an increase of potential security vulnerabilities, associated penalties, and reputational damage. The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reduce gaps in functionality, and (3) optimize overall system performance. Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) advanced analytics on security cameras for monitoring and real time alerting capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems. Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security assets not meeting the industry standard of 5 to 7 years for indoor cameras and 3 to 5 years for outdoor cameras. Alternatives 1 and 2 were not selected due to the risk of security concerns, utilizing equipment that is at end of life and no longer supported, and the risk of a lack of inability to meet regulatory requirements (FERC, NERC, TSA and NRC). The alternative selected maintains compliance, reduces redundancies and gaps in functionality, provides up to date support for the assets and current technological capabilities and optimizes overall performance of physical security systems.	2026-01-01	2028-12-31	-1.00	2,114,320	12,626		1,400,526	-	861,120	110,568	397,504	-	41,334	7,954	-	-	5,434	2,520	-	-
302	2028	Application Currency-Security-O&M	Software(Intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrade. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2028-12-31	-1.00	-	403,127		-	-	-	-	-	-	-	253,970	3,366	-	250,604	-	-	-
303	2028	Enhancements-Security-Capital	Software(Intangible)	Security	This initiative will use Capital funding to make enhancements to existing technology and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements in accordance with accounting rules. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	868,042	82,802		574,991	272,812	35,988	112,241	106,522	-	47,428	52,165	2,570	-	45,057	4,528	-	11
304	2028	Enhancements-Security-O&M	Software(Intangible)	Security	This initiative will use O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2028-12-31	-1.00	-	505,846		-	-	-	-	-	-	-	318,683	24,364	12,774	219,193	62,391	-	(38)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
For the years 2025, 2026, 2027, and 2028
Information Technology Department

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC	ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-ELECTRIC	MATERIAL COSTS-ELECTRIC	LABOR COSTS-ELECTRIC	CONTRACTOR COSTS-ELECTRIC	NON-LABOR OVERHEAD-ELECTRIC	NON-LABOR OTHER-ELECTRIC
305	2028	Forward Web Proxy Services	Software(Intangible)	Security	This project will replace the Company's existing web proxy service platform with a new, modern, and more resilient platform designed to support both secure internet access and advanced data loss prevention capabilities. A web proxy service acts as a secure intermediary between users and the internet, evaluating, filtering, and forwarding traffic while enforcing company security policies. It acts as an intermediary that evaluates, modifies, and forwards the client's requests to the destination web server. This service offers many benefits for the Company such as advanced filtering. Advanced filtering in a forward web proxy service can filter out unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of attacks such as ransomware. The current web proxy platform, implemented in 2021, has caused ongoing operational issues related to web filtering, inconsistent policy enforcement, and intermittent connectivity. These challenges have occasionally limited employee and contractor access to critical internet and cloud-based resources, impacting productivity and increasing security risk. As the Company accelerates its transition to cloud and Software-as-a-Service (SaaS) platforms, maintaining consistent, secure, and reliable internet access is critical. The new platform will provide high availability, improved performance, and enhanced visibility into outbound traffic to ensure that business operations continue seamlessly, even during peak or failover conditions. The platform will also be designed to support flexible deployment models for remote, hybrid, and field-based workers–ensuring that security policies apply consistently regardless of location. In addition to improving reliability, this project introduces data loss prevention (DLP) capabilities as a core function of the web proxy service. These DLP capabilities will help the Company prevent unauthorized transmission of sensitive or regulated information–such as customer data, intellectual property, or operational system details–to unapproved external destinations. Through content inspection, contextual analysis, and integrated policy enforcement, the new solution will identify and block risky behaviors before data leaves the organization. DLP policies will also align with existing information governance frameworks and compliance obligations to provide both proactive protection and auditable oversight of data handling practices. This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilize technology to enable the Company to handle all types of different workloads from varying geographic locations and is highly available; (3) using a mature and scalable web proxy service provider; (4) providing Zero Trust by continuously verifying every connection request; and (5) implementing data loss prevention capabilities on our core web proxy services. The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; (3) potentially changing SAAS cloud vendors; (4) and implementing data loss prevention for web proxy services. The Security team did extensive research on alternative web proxy services solutions. Alternatives considered include: (1) continue to use and maintain the current web proxy services platform as it currently is implemented. This alternative was not chosen due to the previous operational issues with the platform that make it unreliable. The result of an unreliable system means that employees and contractors are unable to access business critical services such as email, Teams, ServiceNow, SharePoint Online,; (2) Route all internet traffic through the Company's corporate data center. This alternative wasn't chosen because the capabilities of firewalls aren't as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) Perform an evaluation between existing product with expanded feature sets, such as data loss prevention and alternative vendors that could replace current system with modern vendor platform for web proxy services. This option was chosen because it offers additional analysis with the potential to enhance existing, in place, products with features such as enhanced data loss prevention mechanisms, browser isolation (the ability to contain web pages so that the web page can't affect the client workstation) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's company strategy.	2027-01-15	2028-01-30	-1.00	4,478,032	492,770	ROM	-	-	-	-	-	-	-	5,730	-	-	5,730	-	-	-
306	**SUBTOTAL**	**2028 Security**										**7,369,195**	**277,340**	**4,104,195**	**1,240,791**	**1,010,151**	**-**	**536,718**	**1,046,233**	**30,299**	**22,114**	**924,408**	**69,436**	**-**	**(27)**
307	**TOTAL**	**2028**										**41,391,869**	**995,135**	**20,261,502**	**5,651,614**	**11,128,314**	**-**	**3,355,103**	**7,755,085**	**152,363**	**292,770**	**3,886,353**	**3,199,738**	**-**	**211,881**

308 The Company fully plans to perform the projects included in the Information Technology cost projections, but the projections do not incorporate a specific confidence level. These costs were not projected using confidence levels. Rough Order Magnitude (ROM) estimates have been reduced by 20% as discussed in my testimony.

EXHIBIT A-21 (SHB-6)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

2025 Union Contract Changes

Report Pulled: 4/15/2026 **Item ID: 13951**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - One Time **Work Type** Project

Alias HR - 2020 Union Changes, Human Resources - 2020 Union Changes, Human Resources -2025 Union Contract Changes, People & Culture - 2025 Union Contract Changes, 2025 Union Contract Changes

Description The Human Resources - 2025 Union Changes project will implement SAP and other system changes required as a result of three collective bargaining agreements which will be renegotiated and ratified.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement Collective bargaining agreements expire every five years for Operating Maintenance and Construction ("OM&C"), Virtual Contact Center ("VCC"), and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2025. The VCC agreement ends August 1, 2025. The Zeeland agreement ends October 1, 2025. Collective bargaining agreements expire every five years for OM&C (Operating Maintenance and Construction), CCC (Customer Contact Center) and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2025 . CCC agreement ends in August 1, 2025. Zeeland agreement ends October 1, 2025. Technology changes are required to reflect these new agreements. Otherwise, employees in these union groups may not be paid appropriately or get correct benefits.

Objectives Completion of this project will provide value to the Company and its customers through: (1) waste elimination by making changes in the software for any pay and benefit changes as required by the new agreements; (2) defect reduction by adding process automation to otherwise manual processes for tracking and recording work, premium, and absence time; and (3) improved employee engagement among the OM&C, CCC, and Zeeland union employees.

Scope The scope of this project encompasses making any system changes required to support the new working agreement for the OM&C, CCC, and Zeeland employees. Exact details will be finalized after the negotiation process is completed and contracts are approved.

Alternatives Three alternatives were considered for this project: (1) Make no system changes after the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, union grievances, significant manual processes leading to greater possibility of error, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances. (2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs. (3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievances. Option (3) was chosen because it leverages current SAP technology, automates what would otherwise require manual processing, and is the least costly option.

DATES (phase end)

Initiation 4/1/2025	**Project Plan & Scope Definition** 5/15/2025	**Final Engineering, Planning & Design** 6/28/2025	**Execution** 12/17/2025
	In-Service/Go-Live 12/18/2025	**Closeout** 5/1/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.060	$0.003	$0.015	$0.015	$0.015	-	-	-	$0.109
Total Cost of Ownership	$0.060	$0.003	$0.015	$0.015	$0.015	-	-	-	**$0.109**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.057	$0.003	-	-	-	-	-	-	**$0.061**
Outside Services	$0.003	-	-	-	-	-	-	-	**$0.003**
Business Expense/Overheads	-	$0.000	-	-	-	-	-	-	**$0.000**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.060	$0.003	-	-	-	-	-	-	**$0.064**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.060	$0.003	$0.015	$0.015	$0.015	-	-	-	**$0.109**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.060	$0.003	$0.015	$0.015	$0.015	-	-	-	**$0.109**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Employee Engagement for the three union groups increases as measured annually in the areas of work/life balance and employee satisfaction.
Avoided Costs	If system changes are not made to automate the changes in the union agreements, additional employees/contractors will need to be hired to manually make the changes. The actual number of employees/contractors is not known at this time since union negotiations have not been finalized.
Intangibles	Union employees are engaged because they are being paid correctly per the union contract.
Avoided Costs	When union employees are paid correctly, the chance of grievances and issues with the NLRB (National Labor Relations Board) decreases. Grievances cost the company time and money, including legal costs.

Advanced Distribution Management System (ADMS) Softwar Report Pulled: 4/13/2026 Item ID: 14016

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Advanced Distribution Management System (ADMS) Enhancements, Advanced Distribution Management System (ADMS) Upgrade, Advanced Distribution Management System (ADMS) Software and Hardware Upgrade

Description The Advanced Distribution Management System Upgrade (ADMS) project will enhance operator experience, simplify maintenance, and provide more powerful and flexible system functionalities. These include advancements in Fault Location, Isolation, and Service Restoration (FLISR), waste elimination within Maestro, the introduction of independent line sensors, a redesign of temporary conditions, and will incorporate operational views of schematics. The project will also be replacing the outdated hardware.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The current ADMS lacks several critical features and improvements that are essential for enhancing operator experience, system maintenance, fault detection, and response capabilities. The existing system struggles with: (1) the current FLISR functionality does not adequately support complex protection requirements and manual switching steps, leading to inefficiencies and potential errors; (2) operators face challenges with passthrough edits and managing conflicts related to devices with tags or temporary conditions, resulting in frequent system reloads and inaccuracies in the as-operated system; (3) the temporary conditions subsystem is cumbersome to use, hindering efficient operations and the ability to support mobile substation and; (4) the current schematic tools do not provide operational views or the ability to save and share views, limiting situational awareness and usability for operators. These gaps result in operational inefficiencies, increased maintenance efforts, and reduced effectiveness in fault management and system operations. Addressing these issues is crucial for improving the overall functionality, usability, and maintenance of the Distribution Management System. (5) The Company runs the risk of increased failure if it does not regularly refresh the infrastructure.

Objectives The project will add value by: (1) improving the user interface and overall experience of the operators, (2) increasing the flexibility and configurability of FLISR, allowing for better support of complex protection requirements and improving solutions for manual switching steps, (3) enhancing the usability of schematics, providing operational views and the ability to save and share views for better situational awareness, (4) developing advanced switch order functionality to support more robust and efficient operations, (5) allowing ADMS to pull real time network model from GIS Utility Network and (6) improving stability and availability of business-critical applications by proactively replacing hardware before it fails.

Scope The scope of the project includes: (1) replacing ADMS hardware, (2) upgrading the existing ADMS platform to the latest packaged version, (3) adding in the feature improvements for Temporary Condition Redesign, Maestro Conflict Resolutions, Independent Line Sensors, FLISR and Schematics, (4) implementing new extraction tool, (5) testing the new functionality in various possible scenarios, and (6) communicating and training users on the new functionality.

Alternatives Alternatives considered include: (1) using outdated equipment and current version of ADMS. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact the Company's ability to respond effectively in storm situations. (2) Moving to a cloud version of ADMS. This option was not selected as the current public cloud platforms do not offer the high security environment required for the ADMS application. Consequently, the vendor platform was not built for cloud environments. (3) Replacing the hardware and upgrading ADMS. This option was selected to alleviate the above concerns.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/2/2026	4/2/2026	8/2/2026	10/7/2027
	In-Service/Go-Live	**Closeout**	
	10/28/2027	11/11/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$2.833	$8.202	-	-	-	-	-	-	$11.036
O&M	$0.388	$0.385	$0.040	$0.040	$0.040	-	-	-	$0.893
Total Cost of Ownership	$3.222	$8.587	$0.040	$0.040	$0.040	-	-	-	**$11.929**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$1.077	$2.751	-	-	-	-	-	-	**$3.828**
Outside Services	$0.411	$1.724	-	-	-	-	-	-	**$2.135**
Business Expense/Overheads	$0.626	$2.339	-	-	-	-	-	-	**$2.966**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$1.091	$1.709	-	-	-	-	-	-	**$2.800**
Licenses, Permits & Fees	$0.016	$0.064	$0.040	$0.040	$0.040	-	-	-	**$0.200**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.222	$8.587	$0.040	$0.040	$0.040	-	-	-	**$11.929**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.388	$0.385	$0.040	$0.040	$0.040	-	-	-	**$0.893**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.388	$0.385	$0.040	$0.040	$0.040	-	-	-	**$0.893**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.833	$8.202	-	-	-	-	-	-	**$11.036**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.833	$8.202	-	-	-	-	-	-	**$11.036**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	FINANCIAL REDUCTION - LND - Reduction in costs for training wire evaluators - TERRA KIRK
Intangibles	Improving the user interface and overall operator experience may lead to higher employee satisfaction and engagement. The project may enhance the company's reputation for reliability and efficiency, which can positively impact customer satisfaction and trust. IS THIS TRUE?
Risk Mitigation	The Company's research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.
Avoided Costs	The new system's improved fault detection and response capabilities could minimize downtime and associated costs. (less crews during storm with FLISR automation) DAWN WEEKS AC send email. Stephen Wilkerson
Intangibles	The project aims to enhance operator experience and system maintenance by improving the user interface and overall system functionality. This will lead to more efficient operations and quicker fault detection and response. The new features, such as advanced switch order functionality and improved schematics, will streamline operations. KRISTI BROWN will see if there is any financial gain here
Avoided Costs	The project will help avoid costs associated with system failures and prolonged outages. By proactively replacing hardware before it fails, the company will prevent costly emergency repairs. KRISHNA
Risk Mitigation	The project will mitigate several risks associated with the current system. By replacing outdated hardware and upgrading the software, the company will reduce the risk of hardware failure and equipment outages. The improved fault detection and response capabilities may also minimize the risk of prolonged outages.
Avoided Costs	The project will reduce the need for manual switching steps, thereby decreasing labor costs (moving employees to more value add work) and reducing human error. JEREMY to help
Intangibles	The upgrade to version 11 of the DMS software will address existing performance issues, such as database performance during storms, ensuring the system performs as expected under high usage.
Avoided Costs	wildfire mitigation STEPHANIE
Avoided Costs	Wire down prediction remote de-energization resulting in wiredown operations needed in critical storm situations. MATH SARAH W. and ALLISON TURNER - AC send e-mail for math

Application Control Enablement

Report Pulled: 4/13/2026 **Item ID: 14019**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Security - Application Control, Application Control Enablement

Description This project will implement a technology called Application Control. Application control, also known as application allow listing, is a security strategy that permits only approved applications to run on a system. This approach helps prevent unauthorized software and malware from executing, thereby enhancing the overall security of the network.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STANI

WORK OBJECTIVES

Problem Statement The rapid multiplication of unauthorized and potentially malicious applications in the current threat landscape poses a substantial risk to corporate data, network infrastructure, and overall business operations. The Company currently does not have an application control solution to mitigate this threat. Without a robust application control product, unauthorized applications can introduce vulnerabilities into the Company's network, leading to data breaches, malware infections, and other cyber threats. Failure to control application usage on the Company's network can result in non-compliance with industry regulations and standards, potentially leading to legal and financial repercussions. Unmanaged applications can cause system conflicts, performance degradation, and downtime, disrupting business continuity and productivity. Inadequate control over applications in the Company's environment increases the risk of data leakage and loss, compromising sensitive information and intellectual property. Uncontrolled application usage can; (1) lead to inefficient use of IT resources; (2) increase licensing costs for software that should not be installed or leveraged by a particular user or department; and (3) reduce efficiency due to deploying computers with more resources than are required because users are installing unneeded software.

Objectives This project creates value for the Company by (1) Protecting the Company's IT environment by preventing unauthorized and potentially harmful applications from being installed or executed; (2) Maintaining adherence to industry regulations and standards by controlling application usage. This helps avoid legal and financial penalties associated with non-compliance and ensures the Company meets its regulatory obligations.

Scope The project scope includes: (1) implementing a Software as a Service (SAAS) application control solution on all corporate computers and (2) implementing stringent restrictions using high enforcement mode on critical assets to prevent running any unauthorized software.

Alternatives Alternatives considered include; (1) removal of local administrator permissions for all users. This option was not chosen as there are legitimate business uses for users to have the ability to make modifications to their workstations.; (2) leverage already existing in place antivirus or endpoint detection and response software. This alternative was not selected as this does not prevent unauthorized installation or running of unauthorized software.; (3) implementing a privilege management tool. A privilege management tool is a security solution designed to control and monitor access to critical resources within an organization. It helps protect against cyber threats by ensuring that only authorized users have access to sensitive information and systems. This alternative was not chosen as it does not prevent a bad actor that has established privilege into the Company network to install malicious software.; and (4) implement an application control solution. This option was chosen because it meets all of the required use cases which reduces risk to corporate data, network infrastructure, and overall business operations.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/6/2025	2/3/2025	4/11/2025	9/26/2025
	In-Service/Go-Live	**Closeout**	
	9/29/2025	10/31/2025	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.696	-	-	-	-	-	-	-	$0.696
O&M	$0.080	$0.025	$0.025	$0.025	-	-	-	-	$0.155
Total Cost of Ownership	$0.776	$0.025	$0.025	$0.025	-	-	-	-	**$0.851**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.075	-	-	-	-	-	-	-	**$0.075**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.129	$0.025	$0.025	$0.025	-	-	-	-	**$0.204**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.572	-	-	-	-	-	-	-	**$0.572**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.776	$0.025	$0.025	$0.025	-	-	-	-	**$0.851**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.080	$0.025	$0.025	$0.025	-	-	-	-	**$0.155**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.080	$0.025	$0.025	$0.025	-	-	-	-	**$0.155**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.696	-	-	-	-	-	-	-	**$0.696**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.696	-	-	-	-	-	-	-	**$0.696**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Government recommendation to implement CISA Cyber Security Performance Goal 2.D – Application Control. Description: Implement application control to allow only authorized software to execute and block unauthorized or malicious applications from running on enterprise assets. Objective: Prevent unauthorized or potentially harmful software from executing, reducing the risk of malware and unauthorized software exploitation.
Risk Mitigation	Protecting the Company's IT environment by preventing unauthorized and potentially harmful applications from being installed or executed

Application Currency-Corporate-O&M

Report Pulled: 4/21/2026 **Item ID: 13357**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Corporate-O&M

Description The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.267	$0.374	$0.240	$0.077	$0.275	$0.112	-	-	$1.345
Total Cost of Ownership	$0.267	$0.374	$0.240	$0.077	$0.275	$0.112	-	-	**$1.345**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.186	$0.350	$0.225	$0.072	$0.257	$0.104	-	-	**$1.194**
Outside Services	$0.059	-	-	-	-	-	-	-	**$0.059**
Business Expense/Overheads	$0.010	$0.024	$0.016	$0.005	$0.018	$0.007	-	-	**$0.080**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.013	-	-	-	-	-	-	-	**$0.013**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.267	$0.374	$0.240	$0.077	$0.275	$0.112	-	-	**$1.345**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.267	$0.374	$0.240	$0.077	$0.275	$0.112	-	-	**$1.345**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.267	$0.374	$0.240	$0.077	$0.275	$0.112	-	-	**$1.345**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Customer-O&M

Report Pulled: 4/13/2026 **Item ID:** 13359

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Customer-O&M

Description The Customer initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades to the Customer digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within Customer are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	-	$0.057	-	$0.057	-	$0.057	-	-	$0.172
Total Cost of Ownership	-	$0.057	-	$0.057	-	$0.057	-	-	**$0.172**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.053	-	$0.053	-	$0.053	-	-	**$0.160**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	$0.004	-	$0.004	-	$0.004	-	-	**$0.011**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	-	$0.057	-	$0.057	-	$0.057	-	-	**$0.172**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.057	-	$0.057	-	$0.057	-	-	**$0.172**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.057	-	$0.057	-	$0.057	-	-	**$0.172**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	The benefit of implementing these upgrades is to improve resiliency and reliability of applications and platforms and reduce their technical debt.

Application Currency-Electric & Gas Shared-Capital

Report Pulled: 4/13/2026 **Item ID:** 13360

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias . Application Currency-Electric & Gas Shared-Capital

Description The Electric and Gas operations initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within the Electric and Gas operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Companys ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	$0.065	-	-	-	-	-	-	$0.065
O&M	-	$0.309	-	-	-	-	-	-	$0.309
Total Cost of Ownership	-	$0.375	-	-	-	-	-	-	**$0.375**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.050	-	-	-	-	-	-	**$0.050**
Outside Services	-	$0.276	-	-	-	-	-	-	**$0.276**
Business Expense/Overheads	-	$0.023	-	-	-	-	-	-	**$0.023**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.025	-	-	-	-	-	-	**$0.025**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	-	$0.375	-	-	-	-	-	-	**$0.375**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.309	-	-	-	-	-	-	**$0.309**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.309	-	-	-	-	-	-	**$0.309**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.065	-	-	-	-	-	-	**$0.065**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.065	-	-	-	-	-	-	**$0.065**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	The benefit of implementing these upgrades is to improve resiliency and reliability of applications and platforms and reduce their technical debt.

Application Currency-Electric & Gas Shared-O&M

Report Pulled: 4/13/2026 **Item ID:** 13361

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Electric & Gas Shared-O&M

Description The Electric and Gas Operations initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Companys ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.115	$0.663	$0.542	$0.732	$0.571	$0.592	-	-	$3.215
Total Cost of Ownership	$0.115	$0.663	$0.542	$0.732	$0.571	$0.592	-	-	**$3.215**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.097	$0.560	$0.456	$0.624	$0.481	$0.518	-	-	**$2.736**
Outside Services	-	$0.064	$0.057	$0.064	$0.057	$0.038	-	-	**$0.279**
Business Expense/Overheads	$0.006	$0.039	$0.029	$0.044	$0.034	$0.036	-	-	**$0.188**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.012	-	-	-	-	-	-	-	**$0.012**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.115	$0.663	$0.542	$0.732	$0.571	$0.592	-	-	**$3.215**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.115	$0.663	$0.542	$0.732	$0.571	$0.592	-	-	**$3.215**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.115	$0.663	$0.542	$0.732	$0.571	$0.592	-	-	**$3.215**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

OTHER VALUE

Type	Description
Risk Mitigation	The benefit of implementing these upgrades is to improve resiliency and reliability of applications and platforms and reduce their technical debt.

Application Currency-Electric-O&M

Report Pulled: 4/14/2026 **Item ID:** 13363

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Electric-O&M

Description The Electric/Generation/Renewables Engineering and Operations initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades to the Electric/Generation/Renewables Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within Electric/Generation/Renewables Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.380	$0.321	$0.218	$0.178	$0.202	$0.162	-	-	$1.460
Total Cost of Ownership	$0.380	$0.321	$0.218	$0.178	$0.202	$0.162	-	-	**$1.460**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.183	$0.200	$0.181	$0.166	$0.166	$0.151	-	-	**$1.048**
Outside Services	$0.180	$0.027	$0.024	-	$0.024	-	-	-	**$0.255**
Business Expense/Overheads	$0.012	$0.014	$0.013	$0.012	$0.012	$0.011	-	-	**$0.072**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.005	$0.080	-	-	-	-	-	-	**$0.085**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.380	$0.321	$0.218	$0.178	$0.202	$0.162	-	-	**$1.460**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.380	$0.321	$0.218	$0.178	$0.202	$0.162	-	-	**$1.460**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.380	$0.321	$0.218	$0.178	$0.202	$0.162	-	-	**$1.460**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	The benefit of implementing these upgrades is to improve resiliency and reliability of applications and platforms and reduce their technical debt.

Application Currency-IT/Digital Foundation-Application Platfor Report Pulled: 4/15/2026 Item ID: 13366

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-IT/Digital Foundation-Application Platforms-Capital

Description The Application Platforms initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio IT Services > Infrastructure > End User Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades in the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within the Application Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.043	-	-	-	-	-	-	-	$0.043
Total Cost of Ownership	$0.043	-	-	-	-	-	-	-	**$0.043**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.042	-	-	-	-	-	-	-	**$0.042**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.001	-	-	-	-	-	-	-	**$0.001**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.043	-	-	-	-	-	-	-	**$0.043**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.043	-	-	-	-	-	-	-	**$0.043**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.043	-	-	-	-	-	-	-	**$0.043**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-IT/Digital Foundation-Application Platforn Report Pulled: 4/13/2026 Item ID: 13367

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-IT/Digital Foundation-Application Platforms-O&M

Description The Application Platforms initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades to the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Application Platforms area are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.126	$0.472	$0.262	$0.367	$0.322	$0.527	-	-	$2.077
Total Cost of Ownership	$0.126	$0.472	$0.262	$0.367	$0.322	$0.527	-	-	**$2.077**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.093	$0.427	$0.245	$0.344	$0.301	$0.492	-	-	**$1.903**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.003	$0.045	$0.017	$0.023	$0.021	$0.034	-	-	**$0.144**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.030	-	-	-	-	-	-	-	**$0.030**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.126	$0.472	$0.262	$0.367	$0.322	$0.527	-	-	**$2.077**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.126	$0.472	$0.262	$0.367	$0.322	$0.527	-	-	**$2.077**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.126	$0.472	$0.262	$0.367	$0.322	$0.527	-	-	**$2.077**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-IT/Digital Foundation-Infrastructure Plat

Report Pulled: 4/13/2026 **Item ID:** 13369

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M

Description The Infrastructure Platforms initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Infrastructure > * > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS & SI

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the Infrastructure Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Infrastructure Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.031	$0.110	$0.039	$0.039	$0.039	$0.039	-	-	$0.295
Total Cost of Ownership	$0.031	$0.110	$0.039	$0.039	$0.039	$0.039	-	-	**$0.295**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.030	$0.050	$0.036	$0.036	$0.036	$0.036	-	-	**$0.225**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.001	$0.003	$0.003	$0.003	$0.003	$0.003	-	-	**$0.014**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.056	-	-	-	-	-	-	**$0.056**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.031	$0.110	$0.039	$0.039	$0.039	$0.039	-	-	**$0.295**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.031	$0.110	$0.039	$0.039	$0.039	$0.039	-	-	**$0.295**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.031	$0.110	$0.039	$0.039	$0.039	$0.039	-	-	**$0.295**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Operational Technology-Capital

Report Pulled: 4/13/2026 **Item ID:** 13370

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Operational Technology-Capital

Description The Operational Technology initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.043	-	-	-	-	-	-	-	$0.043
O&M	-	-	-	-	-	-	-	-	-
Total Cost of Ownership	$0.043	-	-	-	-	-	-	-	**$0.043**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.033	-	-	-	-	-	-	-	**$0.033**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.010	-	-	-	-	-	-	-	**$0.010**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.043	-	-	-	-	-	-	-	**$0.043**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.043	-	-	-	-	-	-	-	**$0.043**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.043	-	-	-	-	-	-	-	**$0.043**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Operational Technology-O&M

Report Pulled: 4/13/2026 **Item ID:** 13371

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Operational Technology-O&M

Description The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.043	$0.254	$0.194	$0.207	$0.184	$0.260	-	-	$1.142
Total Cost of Ownership	$0.043	$0.254	$0.194	$0.207	$0.184	$0.260	-	-	**$1.142**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.041	$0.237	$0.181	$0.193	$0.172	$0.243	-	-	**$1.068**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.001	$0.017	$0.013	$0.014	$0.012	$0.017	-	-	**$0.073**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.043	$0.254	$0.194	$0.207	$0.184	$0.260	-	-	**$1.142**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.043	$0.254	$0.194	$0.207	$0.184	$0.260	-	-	**$1.142**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.043	$0.254	$0.194	$0.207	$0.184	$0.260	-	-	**$1.142**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Application Currency-Security-Capital

Report Pulled: 4/13/2026 **Item ID:** 10483

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Security Application Currency, Application Currency and Enhancements - Security - Capital, Application Currency – Security – Capital, Application Currency-Security-Capital

Description This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MGM

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	$0.153	-	$0.153	-	-	-	$0.306
O&M	-	-	$0.011	-	$0.011	-	-	-	$0.021
Total Cost of Ownership	-	-	$0.164	-	$0.164	-	-	-	**$0.328**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	-	$0.110	-	$0.110	-	-	-	**$0.220**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	-	$0.054	-	$0.054	-	-	-	**$0.108**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	-	-	$0.164	-	$0.164	-	-	-	**$0.328**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	$0.011	-	$0.011	-	-	-	**$0.021**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	$0.011	-	$0.011	-	-	-	**$0.021**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	$0.153	-	$0.153	-	-	-	**$0.306**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	$0.153	-	$0.153	-	-	-	**$0.306**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing these upgrades is to improve resiliency and reliability of applications and platforms and reduce their technical debt.

Application Currency-Security-O&M

Report Pulled: 4/13/2026 **Item ID:** 11337

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Security Application Currency, Application Currency and Enhancements - Security - Capital, Application Currency – Security – Capital, Application Currency – Security – O&M, Application Currency-Security-O&M

Description This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrade

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MGM

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.221	$0.403	$0.403	$0.403	$0.403	$0.403	-	-	$2.237
Total Cost of Ownership	$0.221	$0.403	$0.403	$0.403	$0.403	$0.403	-	-	**$2.237**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.203	$0.372	$0.372	$0.372	$0.372	$0.372	-	-	**$2.062**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.005	$0.026	$0.026	$0.026	$0.026	$0.026	-	-	**$0.135**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.013	$0.005	$0.005	$0.005	$0.005	$0.005	-	-	**$0.040**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.221	$0.403	$0.403	$0.403	$0.403	$0.403	-	-	**$2.237**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.221	$0.403	$0.403	$0.403	$0.403	$0.403	-	-	**$2.237**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.221	$0.403	$0.403	$0.403	$0.403	$0.403	-	-	**$2.237**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing these upgrades is to improve resiliency and reliability of applications and platforms and reduce their technical debt.

ARP-Collaboration

Report Pulled: 4/13/2026 **Item ID: 8213**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Collaboration Asset Refresh,ARP — Collaboration, ARP-Collaboration

Description This project will replace the Company's obsolete or out-of date audio, visual, telephony and other communication collaborative tools and equipment.

Portfolio IT Services > Infrastructure > Network Services > Communication Network > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS & SE

WORK OBJECTIVES

Problem Statement When collaboration assets used to support customer interactions and business operations are obsolete or out-of-date, they are more difficult to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle.

Objectives This project creates value by: (1) ensuring the stability and reliability of the Company's audio, visual, telephony, and other communications systems; and (2) migrating to new collaboration assets.

Scope The project scope consists of: (1) replacing aging collaboration assets; and (2) installing new collaboration assets to meet evolving business requirements.

Alternatives The alternatives considered include: (1) continuing to operate collaboration assets beyond a five-year refresh cycle, or (2) refreshing collaboration assets based on a five-year refresh cycle while evaluating the health of the asset and evolving business requirements. The alternative to operate the collaboration assets beyond a five-year refresh cycle was not selected due to the risk of asset failures would cause stability and reliability issues for employees supporting our customers, as vendors do not provide extended support after five years. The Company chose to refresh the collaboration assets based on a five-year refresh cycle and evaluate the health of the asset and evolving business requirements to reduce the risk of impacting the productivity of employees supporting our customers.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.923	$1.255	$0.675	$2.639	$2.572	$0.850	-	-	$8.914
O&M	$0.516	$0.181	$0.167	$0.207	$0.207	$0.207	-	-	$1.486
Total Cost of Ownership	$1.439	$1.435	$0.843	$2.847	$2.779	$1.058	-	-	**$10.401**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.051	$0.066	$0.094	$0.092	$0.084	$0.071	-	-	**$0.458**
Outside Services	$0.221	$0.174	$0.312	$0.303	$0.386	$0.341	-	-	**$1.736**
Business Expense/Overheads	$0.007	$0.021	$0.043	$0.043	$0.045	$0.036	-	-	**$0.194**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$1.110	$1.174	$0.394	$2.408	$2.264	$0.610	-	-	**$7.961**
Licenses, Permits & Fees	$0.051	-	-	-	-	-	-	-	**$0.051**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.439	$1.435	$0.843	$2.847	$2.779	$1.058	-	-	**$10.401**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.516	$0.181	$0.167	$0.207	$0.207	$0.207	-	-	**$1.486**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.516	$0.181	$0.167	$0.207	$0.207	$0.207	-	-	**$1.486**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.923	$1.255	$0.675	$2.639	$2.572	$0.850	-	-	**$8.914**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.923	$1.255	$0.675	$2.639	$2.572	$0.850	-	-	**$8.914**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

OTHER VALUE

Type	Description
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.

ARP-Cyber-Common

Report Pulled: 4/13/2026 **Item ID: 14027**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP-Cyber Security,Asset Refresh Program - Cyber Security, ARP-Cyber Security, ARP - Cyber - Common, ARP-Cyber-Common

Description This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions.

Portfolio Corporate Services > Security Services > Cyber Security & Shared Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAND/

WORK OBJECTIVES

Problem Statement When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.

Objectives This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.

Scope The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades.

Alternatives The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresh cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warrant repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.499	$1.719	$1.453	$0.749	$0.159	$0.348	-	-	$4.928
O&M	$0.002	$0.019	$0.017	$0.012	$0.006	$0.009	-	-	$0.065
Total Cost of Ownership	$0.501	$1.738	$1.470	$0.761	$0.165	$0.357	-	-	**$4.993**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.016	$0.093	$0.079	$0.044	$0.016	$0.032	-	-	**$0.280**
Outside Services	-	$0.004	$0.004	$0.002	$0.001	$0.002	-	-	**$0.013**
Business Expense/Overheads	$0.004	$0.039	$0.033	$0.017	$0.005	$0.012	-	-	**$0.111**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.301	$1.601	$1.354	$0.698	$0.144	$0.312	-	-	**$4.410**
Licenses, Permits & Fees	$0.179	-	-	-	-	-	-	-	**$0.179**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.501	$1.738	$1.470	$0.761	$0.165	$0.357	-	-	**$4.993**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.002	$0.019	$0.017	$0.012	$0.006	$0.009	-	-	**$0.065**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.002	$0.019	$0.017	$0.012	$0.006	$0.009	-	-	**$0.065**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.499	$1.719	$1.453	$0.749	$0.159	$0.348	-	-	**$4.928**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.499	$1.719	$1.453	$0.749	$0.159	$0.348	-	-	**$4.928**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
System Failure (SAP & Other)	Medium	Medium	The risks associated with not completing the program are impacts on business operations that are in service of the Company's customers. The probability of these risk occurring increases as the age of the asset increases.

OTHER VALUE

Type	Description
Risk Mitigation	The Company's research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: 1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustration and employee downtime; 3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities; 4) continue operating system support as older versions are retired by the manufacturer; and 5) ensure employees have the required software to perform their work.

ARP-Cyber Security

Report Pulled: 4/13/2026 Item ID: 8240

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP-Cyber Security,Asset Refresh Program - Cyber Security, ARP-Cyber Security

Description This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions.

Portfolio Corporate Services > Security Services > Cyber Security & Shared Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MGM

WORK OBJECTIVES

Problem Statement When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.

Objectives This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.

Scope The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a 3-5 year hardware lifecycle; and (2) performing application upgrades.

Alternatives As part of the review process, the alternatives considered were to: (1) upgrade or replace only those assets identified in the plan; (2) upgrade or replace a portion of the assets identified in the plan. Option 1 was not chosen based on continued refresh cycle for cyber security assets to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. Option 2 was not chosen due to the security risk inherent with not replacing assets as per standard refresh cycles increased system vulnerabilities, and out-of-warranty repair costs.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.148	-	-	-	-	-	-	-	$0.148
O&M	$0.008	-	-	-	-	-	-	-	$0.008
Total Cost of Ownership	$0.156	-	-	-	-	-	-	-	**$0.156**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.130	-	-	-	-	-	-	-	**$0.130**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.028	-	-	-	-	-	-	-	**$0.028**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$(0.002)	-	-	-	-	-	-	-	**$(0.002)**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.156	-	-	-	-	-	-	-	**$0.156**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.008	-	-	-	-	-	-	-	**$0.008**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.008	-	-	-	-	-	-	-	**$0.008**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.148	-	-	-	-	-	-	-	**$0.148**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.148	-	-	-	-	-	-	-	**$0.148**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
System Failure (SAP & Other)	Medium	Medium	The risks associated with not completing the program are impacts on business operations that are in service of the Company's customers. The probability of these risk occurring increases as the age of the asset increases. Unless linked to a specific corporate or IT risk, you would skip this section, and go to Other Impacts if risk mitigation

OTHER VALUE

Type	Description
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: 1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustration and employee downtime; 3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities; 4) continue operating system support as older versions are retired by the manufacturer; and 5) ensure employees have the required software to perform their work.

ARP-Cyber-Electric

Report Pulled: 4/15/2026 **Item ID: 14029**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP-Cyber Security,Asset Refresh Program - Cyber Security, ARP-Cyber Security, ARP - Cyber - Common, ARP - Cyber - Electric, ARP-Cyber-Electric

Description This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions for Electric.

Portfolio Corporate Services > Security Services > Cyber Security & Shared Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAND/

WORK OBJECTIVES

Problem Statement When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.

Objectives This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.

Scope The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a three-to-five-year refresh cycle; and (2) performing application upgrades.

Alternatives The alternatives considered include: (1) upgrade or replace only those assets identified in the plan. This alternative was not chosen because maintaining a continued refresch cycle for cyber security assets is necessary to avoid security risks, system vulnerabilities, and out-of-warrant repair costs; (2) upgrade or replace a portion of the assets identified in the plan. This alternative was not chosen due to the inherent security risk of not replacing assets according to standard refresh cycles, which increases system vulnerabilities and out-of-warranty repair costs; and (3) upgrade or replace assets based on a three-to-five-year refresh cycle. This alternative was chosen as it avoids security risk, system vulnerabilities, and out-of-warranty repair costs.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.050	$0.424	$0.471	$0.372	-	$0.521	-	-	$1.839
O&M	$0.002	$0.017	$0.019	$0.015	-	$0.022	-	-	$0.075
Total Cost of Ownership	$0.052	$0.441	$0.490	$0.388	-	$0.543	-	-	**$1.914**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.002	$0.040	$0.046	$0.037	-	$0.051	-	-	**$0.176**
Outside Services	-	$0.002	$0.002	$0.002	-	$0.002	-	-	**$0.007**
Business Expense/Overheads	$0.000	$0.026	$0.016	$0.013	-	$0.018	-	-	**$0.074**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.050	$0.373	$0.426	$0.336	-	$0.471	-	-	**$1.656**
Licenses, Permits & Fees	-	$0.000	$0.000	$0.000	-	$0.000	-	-	**$0.001**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.052	$0.441	$0.490	$0.388	-	$0.543	-	-	**$1.914**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.002	$0.017	$0.019	$0.015	-	$0.022	-	-	**$0.075**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.002	$0.017	$0.019	$0.015	-	$0.022	-	-	**$0.075**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.050	$0.424	$0.471	$0.372	-	$0.521	-	-	**$1.839**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.050	$0.424	$0.471	$0.372	-	$0.521	-	-	**$1.839**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
System Failure (SAP & Other)	Medium	Medium	The risks associated with not completing the program are impacts on business operations that are in service of the Company's customers. The probability of these risk occurring increases as the age of the asset increases.

OTHER VALUE

Type	Description
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: 1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustration and employee downtime; 3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities; 4) continue operating system support as older versions are retired by the manufacturer; and 5) ensure employees have the required software to perform their work.

ARP-Field Device Asset Management (FDAM)

Report Pulled: 4/13/2026 **Item ID:** 8241

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP – Field Device Asset Management (FDAM),ARP — Field Device Asset Management (FDAM), ARP-Field Device Asset Management (FDAM)

Description This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility.

Portfolio IT Services > Infrastructure > End User Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS & S

WORK OBJECTIVES

Problem Statement When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle.

Objectives This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices before they fail; and (2) allowing field workers to complete their job tasks.

Scope The project scope consists of replacing field device assets according to the four-year refresh cycle.

Alternatives Alternatives considered include: (1) using outdated equipment. This alternative was not selected because there would be an increased risk of hardware failure and equipment outages that could impact meter readers' ability to complete job tasks. It would also complicate the Company's efforts to meet the MPSC's meter reading factor and consecutive estimated targets, and it could cause applications to run poorly or stop functioning; (2) The second alternative considered was to replace the hardware. The Company selected this option to alleviate the above concerns.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$2.401	$7.579	$5.534	$4.765	$3.182	$7.376	-	-	$30.837
O&M	$(0.000)	$0.005	$0.004	$0.004	$0.004	$0.004	-	-	$0.019
Total Cost of Ownership	$2.401	$7.584	$5.538	$4.769	$3.185	$7.380	-	-	**$30.857**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.031	$0.134	$0.097	$0.083	$0.055	$0.134	-	-	**$0.534**
Outside Services	$(0.000)	-	$0.000	$0.000	$0.000	$0.000	-	-	**$0.001**
Business Expense/Overheads	$0.002	$0.063	$0.046	$0.039	$0.026	$0.063	-	-	**$0.239**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$2.368	$7.387	$5.395	$4.647	$3.104	$7.183	-	-	**$30.083**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$2.401	$7.584	$5.538	$4.769	$3.185	$7.380	-	-	**$30.857**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$(0.000)	$0.005	$0.004	$0.004	$0.004	$0.004	-	-	**$0.019**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$(0.000)	$0.005	$0.004	$0.004	$0.004	$0.004	-	-	**$0.019**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.401	$7.579	$5.534	$4.765	$3.182	$7.376	-	-	**$30.837**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.401	$7.579	$5.534	$4.765	$3.182	$7.376	-	-	**$30.837**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Field Devices supports/enables asset and operational metric data entry; Work Order Process and Close Out; Resource Management Process (On-Premise vs Traveling/Non-Prem); Supports being able to display Engineering Design Process (Redline/Green Line Drawings), and Storm Restoration in the field by have reliable technology.
Intangibles	Replacing field equipment on a four-year refresh cycle benefits external customers because employees will be able to complete work in a timely manner, which increases customer satisfaction.
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.

ARP-Infoblox Refresh

Report Pulled: 4/13/2026 **Item ID: 6529**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Infoblox Refresh,ARP — Infoblox Refresh, ARP-Infoblox Refresh

Description This project will replace the three legacy core components, Domain Name System ("DNS"), Dynamic Host Configuration Protocol ("DHCP"), and Internet Protocol Address Management ("IPAM") also referred to as DDI ("DNS, DHCP, IPAM") environment with a modern, vendor supported system. Infoblox is the DDI solution that the Company uses to enable seamless network communications across critical systems.

Portfolio IT Services > Infrastructure > End User Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement When Infoblox Assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with Security updates. Consumers Energy also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

Objectives The value of this program includes: (1) enabling the Company to efficiently manage and control their networks; and (2) providing Domain Name System ("DNS"), Dynamic Host Configuration Protocol ("DHCP"), and Internet Protocol Address Management ("IPAM").

Scope The scope of this project includes the replacement of DNS, DHCP and IPAM assets on a 5-7 years refresh cycle.

Alternatives The alternative considered was to continue operating on existing Infoblox equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes. The alternative to replace the existing Infoblox equipment with the latest hardware and software provided by the vendor was selected to avoid these risks and continue a regular refresh cycle.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$0.393	-	-	-	-	-	-	$0.393
O&M	-	$0.007	-	-	-	-	-	-	$0.007
Total Cost of Ownership	-	$0.401	-	-	-	-	-	-	**$0.401**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.011	-	-	-	-	-	-	**$0.011**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	$0.001	-	-	-	-	-	-	**$0.001**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.388	-	-	-	-	-	-	**$0.388**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	-	$0.401	-	-	-	-	-	-	**$0.401**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.007	-	-	-	-	-	-	**$0.007**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.007	-	-	-	-	-	-	**$0.007**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.393	-	-	-	-	-	-	**$0.393**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.393	-	-	-	-	-	-	**$0.393**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Every business-critical application is positively impacted by this refresh. Everything that runs on the network relies on this system.
Risk Mitigation	The company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.

ARP-Local Area Network

Report Pulled: 4/14/2026 **Item ID: 6789**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias LAN Refresh,Local Area Network Refresh, ARP - Local Area Network, ARP-Local Area Network

Description This project will upgrade the Company's entire LAN and a significant portion of the Wireless Local Area Network (WLAN).

Portfolio IT Services > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS & S

WORK OBJECTIVES

Problem Statement

At some Company locations, LAN equipment has been in service since 2011. If the LAN/WLAN hardware and software is not routinely refreshed, the Company will lose the manufacturer support needed for equipment bug fixes, security vulnerability patches, and enhancements. In addition, aging equipment cannot accommodate the increasing demand for wireless devices necessary to perform day-to-day operations that rely on wireless-enabled devices, such as rugged field devices, cell phones, barcode scanners, tablets, and other mobile devices. As equipment ages, it is at risk of higher failure rates, which increases the risk of unplanned outages. In the event of unplanned outages, business areas would not be able to access services on the corporate network including email, SAP, internet, and phones.

Objectives

The project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor supported, thereby ensuring support for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; (6) increasing user productivity through a higher performing wireless network, which increases the productivity and efficiency of office and field employees serving customers; and (7) improving support for wireless Internet Protocol (IP) phones, Internet of Things(IoT) and field devices.

Scope

The project scope includes: (1) refreshing the LAN equipment and software across all Company sites; (2) identifying the required features for the new equipment; (3) implementing the new equipment according to industry best practices; (4) replacing wireless network with upgraded infrastructure and verifying wireless coverage is as expected; and (5) collecting wireless survey data for all Company locations in order to design improved wireless network coverage.

Alternatives

The alternative considered was to continue operating on the existing platform past the vendors end-of-support date. The vendor support period ended in May of 2021, and paying for extended support is not an option offered by the vendor. The risk inherent in not refreshing the platform is a lack of vendor support resulting in an absence of software bug fixes, security updates, and break fixes. The Company chose to replace the existing equipment with the latest hardware and software available, following a five year refresh cycle.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.738	-	-	-	-	-	-	-	$0.738
O&M	$0.100	-	-	-	-	-	-	-	$0.100
Total Cost of Ownership	$0.838	-	-	-	-	-	-	-	**$0.838**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.505	-	-	-	-	-	-	-	**$0.505**
Outside Services	$0.218	-	-	-	-	-	-	-	**$0.218**
Business Expense/Overheads	$0.086	-	-	-	-	-	-	-	**$0.086**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$(0.039)	-	-	-	-	-	-	-	**$(0.039)**
Licenses, Permits & Fees	$0.068	-	-	-	-	-	-	-	**$0.068**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.838	-	-	-	-	-	-	-	**$0.838**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.100	-	-	-	-	-	-	-	**$0.100**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.100	-	-	-	-	-	-	-	**$0.100**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.738	-	-	-	-	-	-	-	**$0.738**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.738	-	-	-	-	-	-	-	**$0.738**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally two to three years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustrations and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work. Manufacturer support will not be provided after May 2021. In the event of unplanned outages, the business would not be able to access the corporate network including email, SAP, internet, and phones.

ARP-Network-Common

Report Pulled: 4/13/2026 **Item ID: 14026**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias LAN Refresh,Local Area Network Refresh, ARP - Local Area Network, ARP-Local Area Network, ARP - Network - Electric, ARP - Network - Gas, ARP - Network - Common, ARP-Network-Common

Description This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks.

Portfolio IT Services > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAND/

WORK OBJECTIVES

Problem Statement When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle.

Objectives This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks.

Scope The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices.

Alternatives The alternatives considered include: (1) continue to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.041	$0.834	$1.515	$0.797	$1.595	$15.890	-	-	$20.673
O&M	-	$0.015	$0.025	$0.014	$0.027	$0.040	-	-	$0.120
Total Cost of Ownership	$0.041	$0.848	$1.540	$0.811	$1.622	$15.929	-	-	**$20.792**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.038	$0.051	$0.027	$0.055	$0.203	-	-	**$0.374**
Outside Services	$0.003	$0.015	$0.028	$0.015	$0.030	$0.080	-	-	**$0.171**
Business Expense/Overheads	-	$0.016	$0.020	$0.010	$0.022	$0.092	-	-	**$0.160**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.023	$0.771	$1.424	$0.752	$1.498	$15.512	-	-	**$19.979**
Licenses, Permits & Fees	$0.015	$0.008	$0.017	$0.008	$0.017	$0.043	-	-	**$0.108**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.041	$0.848	$1.540	$0.811	$1.622	$15.929	-	-	**$20.792**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.015	$0.025	$0.014	$0.027	$0.040	-	-	**$0.120**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.015	$0.025	$0.014	$0.027	$0.040	-	-	**$0.120**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.041	$0.834	$1.515	$0.797	$1.595	$15.890	-	-	**$20.673**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.041	$0.834	$1.515	$0.797	$1.595	$15.890	-	-	**$20.673**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally two to three years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustrations and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work In the event of unplanned outages, the business would not be able to access the corporate network including email, SAP, internet, and phones.

ARP-Network-Electric

Report Pulled: 4/14/2026 **Item ID: 14024**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias LAN Refresh,Local Area Network Refresh, ARP - Local Area Network, ARP-Local Area Network, ARP - Network - Electric, ARP-Network-Electric

Description This project will refresh data center network equipment, local area network (LAN), wireless local area network (WLAN), and equipment to efficiently manage and control the Company's networks for Electric.

Portfolio IT Services > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAND/

WORK OBJECTIVES

Problem Statement When network assets supporting customer interactions and ensuring the stability of mission-critical business operations are obsolete or out-of-date, they become more expensive to support and harder to keep current with security updates. The Company also risks asset failure if it does not adhere to a regular refresh cycle.

Objectives This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor-supported for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; and (6) enabling the Company to efficiently manage and control its networks.

Scope The project scope includes: (1) refreshing network equipment and software assets on a five-year refresh cycle; (2) identifying the required features for the new equipment; and (3) implementing the new equipment according to industry best practices.

Alternatives The alternatives considered include: (1) continue to operate on existing equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes; and (2) refresh network and software assets on a five-year refresh cycle. This alternative was selected to replace the existing equipment with the latest hardware and software to avoid hardware failure and losing vendor support, software bug fixes, security updates, and other software fixes.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.452	$0.066	$0.022	$0.106	$0.118	$7.579	-	-	$8.345
O&M	$0.043	$0.001	$0.001	$0.002	$0.002	$0.008	-	-	$0.056
Total Cost of Ownership	$0.495	$0.067	$0.023	$0.108	$0.120	$7.587	-	-	**$8.400**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.017	$0.005	$0.002	$0.004	$0.007	$0.207	-	-	**$0.243**
Outside Services	-	$0.001	$0.000	$0.002	$0.002	$0.052	-	-	**$0.058**
Business Expense/Overheads	$0.001	$0.002	$0.001	$0.002	$0.003	$0.098	-	-	**$0.107**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.349	$0.059	$0.020	$0.100	$0.107	$7.219	-	-	**$7.852**
Licenses, Permits & Fees	$0.127	$0.000	$0.000	$0.000	$0.001	$0.012	-	-	**$0.140**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.495	$0.067	$0.023	$0.108	$0.120	$7.587	-	-	**$8.400**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.043	$0.001	$0.001	$0.002	$0.002	$0.008	-	-	**$0.056**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.043	$0.001	$0.001	$0.002	$0.002	$0.008	-	-	**$0.056**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.452	$0.066	$0.022	$0.106	$0.118	$7.579	-	-	**$8.345**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.452	$0.066	$0.022	$0.106	$0.118	$7.579	-	-	**$8.345**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	The Company's research demonstrates that industry standards on refreshing hardware are generally two to three years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustrations and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work In the event of unplanned outages, the business would not be able to access the corporate network including email, SAP, internet, and phones.

ARP-Operational Technology Support Common

Report Pulled: 4/13/2026 **Item ID:** 14032

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Critical Infrastructure Support, 2014 CIS Asset Refresh,ARP — Operational Technology Support, ARP — Operational Technology Support Electric, ARP-Operational Technology Support Electric, ARP-Operational Technology Support Common

Description The Asset Refresh Program (ARP)-Operational Technology (OT) Support Common project will replace dated and obsolete servers shared by Electric and Gas on a rotating five-year refresh schedule.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement When Operational Technology Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle.

Objectives This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure.

Scope The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements.

Alternatives The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$1.769	$1.656	$1.472	$2.600	$4.100	$0.780	-	-	$12.377
O&M	$0.170	$0.153	$0.147	$0.255	$0.515	$0.076	-	-	$1.316
Total Cost of Ownership	$1.940	$1.808	$1.619	$2.855	$4.615	$0.856	-	-	**$13.693**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.030	$0.049	$0.053	$0.082	$0.082	$0.024	-	-	**$0.319**
Outside Services	$0.018	-	-	-	-	-	-	-	**$0.018**
Business Expense/Overheads	$0.007	$0.115	$0.021	$0.033	$0.033	$0.010	-	-	**$0.220**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.879	$1.644	$1.545	$2.740	$4.500	$0.822	-	-	**$12.130**
Licenses, Permits & Fees	$1.006	-	-	-	-	-	-	-	**$1.006**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$1.940	$1.808	$1.619	$2.855	$4.615	$0.856	-	-	**$13.693**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.170	$0.153	$0.147	$0.255	$0.515	$0.076	-	-	**$1.316**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.170	$0.153	$0.147	$0.255	$0.515	$0.076	-	-	**$1.316**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$1.769	$1.656	$1.472	$2.600	$4.100	$0.780	-	-	**$12.377**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$1.769	$1.656	$1.472	$2.600	$4.100	$0.780	-	-	**$12.377**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	The risks associated with not completing the program are both disruptive and adverse performance impacts on business operations that Operational Technology supports, which includes the Merchant Operations Center, and System Control. The probability of these risks occurring increases as the age of the asset increases. Specifically: (1) There will be no security updates without the replacement, which increases our vulnerability. (2) Monitors to maintain the equipment will not be available. (3) Cyber security vulnerabilities will increase with aged systems, which make the systems more prone to attack and compromise. (4) This ensures compliance with the North American Electric Reliability Corporation Critical Infrastructure Protection Plan (NERC/CIP). NERC can fine Consumers Energy $1.2 million per incident per day for violating NERC.

OTHER VALUE

Type	Description
Risk Mitigation	The Company's research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.
Intangibles	This reduces the risk of potential cyber security incidents because upgraded systems have been built and calibrated for newer types of cyber-attacks. If the Operational Technology systems are not upgraded, it will affect the ability for Consumers Energy to meet the regulatory and compliance requirements needed for successful customer-facing operations.

ARP-Operational Technology Support Electric

Report Pulled: 4/14/2026 **Item ID:** 11617

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Critical Infrastructure Support, 2014 CIS Asset Refresh,ARP — Operational Technology Support, ARP — Operational Technology Support Electric, ARP-Operational Technology Support Electric

Description The Asset Refresh Program (ARP)-Operational Technology (OT) Support Electric project will replace dated and obsolete servers on a rotating five-year refresh schedule.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVIC

WORK OBJECTIVES

Problem Statement When Operational Technology Assets that are used to ensure the safety and reliability of technology that supports critical electric operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and run the risk of failure if the Company does not adhere to a regular refresh cycle.

Objectives This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical electric infrastructure.

Scope The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements.

Alternatives The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle or (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety issues for customers, as vendors do not provide extended support after five years. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Electric SCADA.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.362	$0.191	$1.834	$0.294	$0.563	$0.180	-	-	$3.424
O&M	$0.060	$0.017	$0.276	$0.052	$0.128	$0.017	-	-	$0.550
Total Cost of Ownership	$0.422	$0.208	$2.110	$0.346	$0.691	$0.197	-	-	**$3.974**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.107	$0.012	$0.095	$0.057	$0.053	$0.012	-	-	**$0.337**
Outside Services	$(0.026)	-	-	-	-	-	-	-	**$(0.026)**
Business Expense/Overheads	$0.019	$0.016	$0.039	$0.023	$0.021	$0.005	-	-	**$0.124**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.122	$0.180	$1.975	$0.266	$0.617	$0.180	-	-	**$3.340**
Licenses, Permits & Fees	$0.200	-	-	-	-	-	-	-	**$0.200**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.422	$0.208	$2.110	$0.346	$0.691	$0.197	-	-	**$3.974**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.060	$0.017	$0.276	$0.052	$0.128	$0.017	-	-	**$0.550**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.060	$0.017	$0.276	$0.052	$0.128	$0.017	-	-	**$0.550**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.362	$0.191	$1.834	$0.294	$0.563	$0.180	-	-	**$3.424**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.362	$0.191	$1.834	$0.294	$0.563	$0.180	-	-	**$3.424**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	The risks associated with not completing the program are both disruptive and adverse performance impacts on business operations that Operational Technology supports, which includes the Merchant Operations Center, and System Control. The probability of these risks occurring increases as the age of the asset increases. Specifically: (1) There will be no security updates without the replacement, which increases our vulnerability. (2) Monitors to maintain the equipment will not be available. (3) Cyber security vulnerabilities will increase with aged systems, which make the systems more prone to attack and compromise. (4) This ensures compliance with the North American Electric Reliability Corporation Critical Infrastructure Protection Plan (NERC/CIP). NERC can fine Consumers Energy $1.2 million per incident per day for violating NERC.

OTHER VALUE

Type	Description
Risk Mitigation	The Company's research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.
Intangibles	This reduces the risk of potential cyber security incidents because upgraded systems have been built and calibrated for newer types of cyber-attacks. If the Operational Technology systems are not upgraded, it will affect the ability for Consumers Energy to meet the regulatory and compliance requirements needed for successful customer-facing operations.

ARP-Physical Security

Report Pulled: 4/14/2026 **Item ID: 8176**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Physical Security,Physical Security Asset Refresh, ARP-Physical Security

Description The ARP-Physical Security, formerly known as Physical Security Asset Refresh, will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MGM

WORK OBJECTIVES

Problem Statement The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring alerts, compliance with regulations and guidelines, and faster responses to emergencies and incidents. This could result in an increase of potential security vulnerabilities, associated penalties, and reputational damage.

Objectives The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reduce gaps in functionality; and (3) optimize overall system performance.

Scope Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) advanced analytics on security cameras for monitoring and real time alerting capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems.

Alternatives Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security assets not meeting the industry standard of 5 to 7 years for indoor cameras and 3 to 5 years for outdoor cameras. Alternatives 1 and 2 were not selected due to the risk of security concerns, utilizing equipment that is at end of life and no longer supported, and the risk of a lack of inability to meet regulatory requirements (FERC, NERC, TSA and NRC). The alternative selected maintains compliance, reduces redundancies and gaps in functionality, provides up to date support for the assets and current technological capabilities and optimizes overall performance of physical security systems.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$2.310	$2.113	$2.114	$2.114	$2.114	$1.427	-	-	$12.193
O&M	$0.001	$0.013	$0.013	$0.013	$0.013	-	-	-	$0.051
Total Cost of Ownership	$2.311	$2.125	$2.127	$2.127	$2.127	$1.427	-	-	**$12.244**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.044	$0.164	$0.164	$0.164	$0.164	-	-	-	**$0.699**
Outside Services	$0.552	$0.589	$0.589	$0.589	$0.589	-	-	-	**$2.908**
Business Expense/Overheads	$(0.068)	$0.074	$0.074	$0.074	$0.074	$0.127	-	-	**$0.355**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$1.770	$1.299	$1.300	$1.300	$1.300	$1.300	-	-	**$8.269**
Licenses, Permits & Fees	$0.013	-	-	-	-	-	-	-	**$0.013**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$2.311	$2.125	$2.127	$2.127	$2.127	$1.427	-	-	**$12.244**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.001	$0.013	$0.013	$0.013	$0.013	-	-	-	**$0.051**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.001	$0.013	$0.013	$0.013	$0.013	-	-	-	**$0.051**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.310	$2.113	$2.114	$2.114	$2.114	$1.427	-	-	**$12.193**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.310	$2.113	$2.114	$2.114	$2.114	$1.427	-	-	**$12.193**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Theft/Accidental Disclosure	Low	Medium	Having cameras and other physical security assets can help uncover activities leading to potential thefts and or accidents.

OTHER VALUE

Type	Description
Risk Mitigation	Lack of life cycle replacement wouldn't allow for integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster, more effective/consistent response to emergencies and incidents which could result in the increase of potential security vulnerabilities, associated penalties and reputation damage.
Intangibles	Security Visibility - Having updated camera/Door systems helps the security command center have been visibility into often un-monitored areas.

ARP-Printer Asset Management (PAM)

Report Pulled: 4/13/2026 **Item ID: 6671**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Printer Asset Management,ARP — Printer Asset Management (PAM), ARP-Printer Asset Management (PAM)

Description This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one.

Portfolio IT Services > Infrastructure > End User Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS & S

WORK OBJECTIVES

Problem Statement When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

Objectives This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications.

Scope The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. This does not mean that all printers are replaced after five years – merely that printers are assessed on a five-year cycle for possible replacement.

Alternatives The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years would require the printers to be assessed monthly to ensure they are not run to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$1.560	$0.185	$0.675	$0.233	$1.063	$1.427	-	-	$5.144
O&M	$0.003	$0.005	$0.008	$0.008	$0.008	$0.008	-	-	$0.042
Total Cost of Ownership	$1.563	$0.190	$0.684	$0.242	$1.072	$1.436	-	-	**$5.186**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.086	$0.003	$0.019	$0.011	$0.030	$0.039	-	-	**$0.187**
Outside Services	$0.000	-	$0.000	$0.000	$0.000	$0.000	-	-	**$0.001**
Business Expense/Overheads	$0.016	$0.002	$0.006	$0.002	$0.011	$0.015	-	-	**$0.051**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$1.461	$0.185	$0.660	$0.228	$1.031	$1.382	-	-	**$4.947**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.563	$0.190	$0.684	$0.242	$1.072	$1.436	-	-	**$5.186**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.003	$0.005	$0.008	$0.008	$0.008	$0.008	-	-	**$0.042**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.003	$0.005	$0.008	$0.008	$0.008	$0.008	-	-	**$0.042**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.560	$0.185	$0.675	$0.233	$1.063	$1.427	-	-	**$5.144**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.560	$0.185	$0.675	$0.233	$1.063	$1.427	-	-	**$5.144**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	If Consumers Energy does not stay current with printer hardware, then it would not be able to use the updated software and would lose print functionality.

OTHER VALUE

Type	Description
Risk Mitigation	The company's research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.

ARP-Radio

Report Pulled: 4/13/2026 **Item ID: 8234**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Wireless Network,ARP — Wireless Network, ARP — Radio, ARP-Radio

Description This project will refresh hardware to include: 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices, vehicle consoles in service trucks, other communications equipment, and associated test equipment. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 10-year lifecycle basis. Cellular modems are refreshed on a five-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle.

Portfolio IT Services > Infrastructure > Network Services > * > * > *

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WORK OBJECTIVES

Problem Statement 800MHz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customers service and critical infrastructure. Company radio and cellular systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing or becoming obsolete. The refresh of this equipment in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety.

Objectives This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure.

Scope The project scope consists of: (1) scheduled replacement of radios, modems, consoles; and (2) installing additional radios, modems, and console assets to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters and systems.

Alternatives The alternatives considered include: (1) Replacing the existing units with new units from other radio and modem manufacturers; (2) Purchasing new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$1.499	$1.457	$1.739	$1.735	$2.222	$2.283	-	-	$10.935
O&M	$0.165	$0.097	$0.093	$0.084	$0.076	$0.007	-	-	$0.522
Total Cost of Ownership	$1.665	$1.554	$1.832	$1.819	$2.298	$2.289	-	-	**$11.457**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.143	$0.044	$0.041	$0.037	$0.045	$0.039	-	-	**$0.350**
Outside Services	$(0.110)	$0.040	$0.042	$0.040	$0.043	$0.036	-	-	**$0.091**
Business Expense/Overheads	$0.013	$0.021	$0.022	$0.020	$0.023	$0.021	-	-	**$0.120**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$1.713	$1.448	$1.727	$1.722	$2.187	$2.194	-	-	**$10.991**
Licenses, Permits & Fees	$(0.095)	-	-	-	-	-	-	-	**$(0.095)**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.665	$1.554	$1.832	$1.819	$2.298	$2.289	-	-	**$11.457**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.165	$0.097	$0.093	$0.084	$0.076	$0.007	-	-	**$0.522**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.165	$0.097	$0.093	$0.084	$0.076	$0.007	-	-	**$0.522**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.499	$1.457	$1.739	$1.735	$2.222	$2.283	-	-	**$10.935**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.499	$1.457	$1.739	$1.735	$2.222	$2.283	-	-	**$10.935**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Cost avoidance of future Modem purchases. Transitioning cellular services from modems to devices avoids future yearly modem refresh costs of approximately $420,000.
Risk Mitigation	The company' research demonstrates that industry standards on refreshing radio hardware is generally seven to ten years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; (2) mitigate customer frustration and employee downtime; (3) maintain high standards for customer and employee safety; and (4) maintain technology currency for employees to perform their work.
Intangibles	The radio system funded through the ARP — Radio project supports core business functions such as storm restoration, emergency gas leak repair, and day-to-day customer support. By reinvesting in the system Consumers Energy extends the effectiveness of the system.
Risk Mitigation	The risk inherent in not replacing these items is the extended support cost, which amounts to $225,000 annually. Moreover, additional service hour, parts replacement, material, and setup costs would be incurred for outfitting of vehicles.

ARP-Server and Storage

Report Pulled: 4/13/2026 **Item ID: 8755**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Server and Storage,ARP — Server and Storage, ARP-Server and Storage

Description This project will replace or augment server and storage infrastructure for the Company.

Portfolio IT Services > Infrastructure > Data Center - Storage > * > * > *

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WORK OBJECTIVES

Problem Statement

When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be more challenging to keep current with Security updates. The Company also runs the risk of failure of these assets impacting customer interactions and business operations if it does not adhere to a regular five to seven-year refresh cycle.

Objectives

This project creates value for the Company through: (1) improved stability and availability of business-critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use.

Scope

The scope of this program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements.

Alternatives

The alternatives considered were to (1) purchase extended maintenance; (2) move some of these assets to the cloud with the Digital -Hybrid Cloud and Data Center Migration project or: (3) replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.345	-	-	$1.175	$0.960	-	-	-	$2.480
O&M	$0.014	-	-	$0.014	-	-	-	-	$0.028
Total Cost of Ownership	$0.360	-	-	$1.189	$0.960	-	-	-	**$2.508**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.017	-	-	$0.135	-	-	-	-	**$0.152**
Outside Services	$0.004	-	-	-	-	-	-	-	**$0.004**
Business Expense/Overheads	$0.001	-	-	$0.094	-	-	-	-	**$0.095**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.125	-	-	$0.960	$0.960	-	-	-	**$2.045**
Licenses, Permits & Fees	$0.213	-	-	-	-	-	-	-	**$0.213**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.360	-	-	$1.189	$0.960	-	-	-	**$2.508**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.014	-	-	$0.014	-	-	-	-	**$0.028**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.014	-	-	$0.014	-	-	-	-	**$0.028**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.345	-	-	$1.175	$0.960	-	-	-	**$2.480**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.345	-	-	$1.175	$0.960	-	-	-	**$2.480**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	Consumers Energy's vendor, Nutanix only offers full support for seven years after purchase of a solution. After the end of support no more security patches are available and if an issue is encountered the manufacturer will not assist in resolving.

OTHER VALUE

Type	Description
Avoided Costs	If all the existing hardware environment went beyond seven years, O&M would increase would by $202,000. Each 1/7th of the environment not upgraded would equate to an increase in O&M by $30,000.
Avoided Costs	Maintenance costs would increase by about 15% after seven years over current amounts in the ITPM.
Intangibles	Research firm IDC Economics reports that without proactive replacement server performance drops by 39%, annual support costs increase 148%, application management costs increase 40%, and unplanned downtime hours increase by 62%.
Risk Mitigation	The Company's research demonstrates that industry standards on refreshing hardware are generally five to seven years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; (2) avert customer frustration and employee downtime; (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities; (4) continue operating system support as older versions are retired by the manufacturer; and (5) ensure employees have the required software to perform their work.

ARP-Workstation Asset Management (WAM)

Report Pulled: 4/13/2026 **Item ID: 8242**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Workstation Asset Management (WAM),ARP — Workstation Asset Management (WAM), ARP-Workstation Asset Management (WAM)

Description This project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates.

Portfolio IT Services > Infrastructure > End User Computing > * > * > *

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WORK OBJECTIVES

Problem Statement When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

Objectives This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks.

Scope The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources.

Alternatives The alternatives considered were to purchase extended maintenance, move some of these assets to the cloud with the Digital -Hybrid Cloud and Data Center Migration project, or to replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven year cycle as it is the most cost-effective option.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$8.044	$5.542	$6.998	$11.085	$11.228	$6.215	-	-	$49.113
O&M	$0.098	$0.052	$0.101	$0.101	$0.101	$0.101	-	-	$0.555
Total Cost of Ownership	$8.142	$5.594	$7.099	$11.186	$11.330	$6.317	-	-	**$49.668**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.304	$0.113	$0.129	$0.179	$0.190	$0.131	-	-	**$1.046**
Outside Services	$0.000	$0.110	$0.110	$0.160	$0.171	$0.112	-	-	**$0.664**
Business Expense/Overheads	$0.096	$0.060	$0.113	$0.140	$0.146	$0.114	-	-	**$0.670**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$7.726	$5.311	$6.747	$10.707	$10.823	$5.959	-	-	**$47.273**
Licenses, Permits & Fees	$0.015	-	-	-	-	-	-	-	**$0.015**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$8.142	$5.594	$7.099	$11.186	$11.330	$6.317	-	-	**$49.668**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.098	$0.052	$0.101	$0.101	$0.101	$0.101	-	-	**$0.555**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.098	$0.052	$0.101	$0.101	$0.101	$0.101	-	-	**$0.555**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$8.044	$5.542	$6.998	$11.085	$11.228	$6.215	-	-	**$49.113**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$8.044	$5.542	$6.998	$11.085	$11.228	$6.215	-	-	**$49.113**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	There is a high risk of hardware failure, the inability to keep current with security updates, and software compatibility issues without the four-year refresh.

OTHER VALUE

Type	Description
Avoided Costs	Future year costs would increase if equipment is not refreshed in planned year.
Risk Mitigation	The company' research demonstrates that industry standards on refreshing hardware are generally eight years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.
Technology Capability	The WAM program enables and supports all administrative, engineering, operational, and corporate process and activities.

Asset Accounting Tax Upgrade

Report Pulled: 4/15/2026 **Item ID:** 13966

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Asset Accounting Upgrade, Asset Accounting Upgrade 2026, Asset Accounting Upgrade 2025-2026, Asset Accounting Upgrade 2026, Asset Accounting Upgrade 2025-2027, Asset Accounting Tax Upgrade

Description The project will upgrade the Company's current on-premise accounting asset management tax software to the SaaS version as required by the vendor ensuring continued support of a critical financial application and providing new functionality.

Portfolio IT Services > Applications > Corporate Services > * > * > *

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WORK OBJECTIVES

Problem Statement In 2025, standard vendor support ends for the current on-premise PowerTax software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the tax fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility.

Objectives This project creates value for the Company by ensuring compliance with regulated and financial accounting within the tax fixed asset sub-ledger. In addition, the project adds value by: (1) moving to a SaaS solution in order stay supported; and (2) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.

Scope The project scope includes: (1) evaluating current vendor/product solutions with market leaders; and (2) upgrading the vendor software from the current version to the newer SaaS version; or replacing it.

Alternatives Alternatives considered include: (1) evaluating SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features such as centralized tax error processing. (2) evaluating other software options. This option may not provide appropriate regulatory reporting and other needed improvements and introduces several complexities and costs: Integration Challenges as PowerPlan modules are designed to work seamlessly together and data synch, mapping, and real-time updates may not be as robust as with native modules; Loss of Automation and Efficiency as there may be manual data transfers, duplicate entries and reduced automation increasing labor costs and risk of mistakes; Higher IT and Support Costs as maintaining two asset accounting systems means higher IT overhead with upgrades, troubleshooting, and user training; Reduced Data Integrity and Security as splitting tax data between systems can create gaps in data integrity, audit trails, and security controls; and Limited Vendor Accountability as when issues arise, vendors may point to integration boundaries making troubleshooting and issue resolution slower and more complicated. (3) moving entire PowerPlan suite, which includes PowerTax, to their cloud option. This option would be expensive from a licensing and integration build perspective, has an unclear timeline, and would remove the opportunity for direct database control. (4) waiting until a future upgrade cycle. This option introduces technical risk and potential financial processing risk. (5) upgrading to a newer version of the current solution. This is the preferred option as it will provide more frequent software upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

DATES (phase end)

Initiation 2/1/2027	**Project Plan & Scope Definition** 3/31/2027	**Final Engineering, Planning & Design** 4/30/2027	**Execution** 9/2/2027
	In-Service/Go-Live 10/15/2027	**Closeout** 1/31/2028	

FUNDING SUMMARY

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.343	$0.057	$0.274	$0.274	$0.274	-	-	-	$1.221
Total Cost of Ownership	$0.343	$0.057	$0.274	$0.274	$0.274	-	-	-	**$1.221**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.107	$0.027	-	-	-	-	-	-	**$0.134**
Outside Services	$0.214	$0.027	-	-	-	-	-	-	**$0.240**
Business Expense/Overheads	$0.022	$0.004	-	-	-	-	-	-	**$0.026**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	$0.274	$0.274	$0.274	-	-	-	**$0.821**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.343	$0.057	$0.274	$0.274	$0.274	-	-	-	**$1.221**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.343	$0.057	$0.274	$0.274	$0.274	-	-	-	**$1.221**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.343	$0.057	$0.274	$0.274	$0.274	-	-	-	**$1.221**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Performing this upgrade ensures continued vendor support of a critical application.
Intangibles	The Company improves its financial visibility and ability to react to changing information as a result of running the allocation process on a more frequent basis.
Risk Mitigation	Upgrading the software ensures continued compliance with regulated and financial accounting within the fixed asset sub-ledger.

Asset Accounting Upgrade 2025-2026

Report Pulled: 4/15/2026 **Item ID: 13298**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Asset Accounting Upgrade, Asset Accounting Upgrade 2026, Asset Accounting Upgrade 2025-2026, Asset Accounting Upgrade 2026, Asset Accounting Upgrade 2025-2027, Asset Accounting Upgrade 2025-2026

Description The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement Standard vendor support will be ending for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complex testing activities and too many version increases at any one time.

Objectives This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted.

Scope The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor software from the current version to the newer version.

Alternatives Alternatives considered include: (1) Evaluated SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) Evaluated other software options. This option would introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) Upgrade to the newest version of current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2025	3/31/2025	4/30/2025	9/2/2025
	In-Service/Go-Live	**Closeout**	
	10/15/2025	1/31/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.303	$0.284	-	-	-	-	-	-	$0.588
Total Cost of Ownership	$0.303	$0.284	-	-	-	-	-	-	**$0.588**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.037	$0.173	-	-	-	-	-	-	**$0.211**
Outside Services	$0.265	$0.109	-	-	-	-	-	-	**$0.374**
Business Expense/Overheads	$0.002	$0.002	-	-	-	-	-	-	**$0.003**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.303	$0.284	-	-	-	-	-	-	**$0.588**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.303	$0.284	-	-	-	-	-	-	**$0.588**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.303	$0.284	-	-	-	-	-	-	**$0.588**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Performing this upgrade ensures continued vendor support of a critical application.
Intangibles	The Company improves its financial visibility and ability to react to changing information as a result of running the allocation process on a more frequent basis.
Risk Mitigation	Upgrading the software ensures continued compliance with regulated and financial accounting within the fixed asset sub-ledger.

Asset Accounting Upgrade 2027-2028

Report Pulled: 4/14/2026 **Item ID: 13967**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Asset Accounting Upgrade, Asset Accounting Upgrade 2026, Asset Accounting Upgrade 2025-2026, Asset Accounting Upgrade 2026, Asset Accounting Upgrade 2025-2027, Asset Accounting Upgrade 2025-2026, Asset Accounting Upgrade 2027-2028

Description The project will upgrade the Company's current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement Standard vendor support will be ending for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complex testing activities and too many version increases at any one time.

Objectives This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted.

Scope The project scope includes: (1) evaluating current vendor/product solution with market leaders; and (2) upgrading the vendor software from the current version to a newer version.

Alternatives Alternatives considered include: (1) Evaluated SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) Evaluated other software options. This option would introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements; (3) Address cloud possibilities. This option is expensive and has an unclear timeline roadmap; (4) wait until a future upgrade cycle. This option introduces technical risk; (5) Upgrading to a newer version of current solution. This is the preferred option as it will provide more frequent software upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2027	3/31/2027	4/30/2027	9/2/2027
	In-Service/Go-Live	**Closeout**	
	10/15/2027	1/31/2028	

FUNDING SUMMARY

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.600	$0.071	-	-	-	-	-	-	$0.672
Total Cost of Ownership	$0.600	$0.071	-	-	-	-	-	-	**$0.672**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.160	$0.013	-	-	-	-	-	-	**$0.174**
Outside Services	$0.401	$0.053	-	-	-	-	-	-	**$0.454**
Business Expense/Overheads	$0.039	$0.005	-	-	-	-	-	-	**$0.044**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.600	$0.071	-	-	-	-	-	-	**$0.672**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.600	$0.071	-	-	-	-	-	-	**$0.672**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.600	$0.071	-	-	-	-	-	-	**$0.672**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Performing this upgrade ensures continued vendor support of a critical application.
Intangibles	The Company improves its financial visibility and ability to react to changing information as a result of running the allocation process on a more frequent basis.
Risk Mitigation	Upgrading the software ensures continued compliance with regulated and financial accounting within the fixed asset sub-ledger.

AxWay Secure Transport 2024 Upgrade

Report Pulled: 4/20/2026 **Item ID: 11748**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , AxWay Secure Transport Upgrade, AxWay Secure Transport 2024 Upgrade, AxWay Secure Transport 2025 Upgrade, AxWay Secure Transport 2024 Upgrade

Description Axway SecureTransport is the Company's multi-protocol Managed File Transfer ("MFT") gateway for securing, managing, and tracking data file flow for business partners and external vendors. Files impacting billing, HR, Supply Chain, Finance, Alternate Energy Programs, Front Office, Back Office, Device Management, Outage Management and Business Reporting functions utilize these services. This project will update the platform to the current software version, enabling cost saving operational enhancements while retaining data security and platform supportability.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement As Axway Secure Transport is the public-facing managed file transfer gateway, maintaining platform version integrity is critical to ensuring it remains secure and supportable in the event of a cyber attack, outage or other critical incident. A prolonged outage or incident, for any reason, compromises the ability of the Company to perform mission-critical business transactions in finance, operations and direct customer support. Upgrading this application also gives the Company the opportunity to properly scale SecureTransport and take advantage of the growing demand for additional, cost-savings features of the tool, such as managing internal Electronic Data Interchange transactions.

Objectives The value this project brings Consumers Energy and customers includes: (1) Addressing known problems and limitations of the current software and hardware platforms. (2) Ensuring continued secure, scalable, and critical data transmission services running through Axway continue functioning. (3) Creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste. (4) Merging/streamlining the company data file transfer services reducing cyber-attack vectors and creates a more easily maintained and monitored security model.

Scope The scope of this project includes (1) Upgrading the application and database to the current released and supported versions. (2) Refreshing the underlying application infrastructure by upgrading to the latest operating system and hardware platforms. (3) Enable and test expanded Electronic Data Interchange (EDI) functionality.

Alternatives Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because the Axway SecureTransport platform handles critical Company financial, HR and operational transactions--the risk associated with problems stemming from an outdated and unsupported version is too high. Nor would the waste elimination benefits of using the upgraded Axway platform to start consolidating EDI for CE be realized. (2) Replacing the platform. The estimated project costs and timetable for replacing the business functions currently performed by the existing Axway SecureTransport platform would be extensive, and operationally, it is not well suited for a cloud or hybrid cloud solution. In addition to significant platform, application, implementation and functional testing costs, replacing it would require extensive coordination and testing with all of the internal and external account holders, taking upwards of one calendar year. (3) Upgrading the platform. This provides the Company the most cost-effective alternative, balancing costs, known risks, and even growing business capacity and productivity.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/1/2024	1/15/2024	2/1/2024	2/15/2024
	In-Service/Go-Live	**Closeout**	
	9/14/2024	9/20/2024	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.075	$0.047	-	-	-	-	-	-	$0.122
Total Cost of Ownership	$0.075	$0.047	-	-	-	-	-	-	**$0.122**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.039	$0.024	-	-	-	-	-	-	**$0.063**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.003	$0.001	-	-	-	-	-	-	**$0.004**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.032	$0.022	-	-	-	-	-	-	**$0.055**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.075	$0.047	-	-	-	-	-	-	**$0.122**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.075	$0.047	-	-	-	-	-	-	**$0.122**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.075	$0.047	-	-	-	-	-	-	**$0.122**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	An out-of-support version of Secure Transport that Axway no longer provides hotfixes for will put the company network at risk as this is a external (internet) facing application.

OTHER VALUE

Type	Description
Intangibles	Newer versions of Secure Transport will assist in improving performance of the platform through bug fixes and performance tuning.
Risk Mitigation	The upgrade work will allow CE to harden the application and eliminate a significant single point of failure.

AxWay Secure Transport 2027 Upgrade

Report Pulled: 4/16/2026 **Item ID:** 11753

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , AxWay Secure Transport Upgrade, AxWay Secure Transport 2026 Upgrade, AxWay Secure Transport 2027 Upgrade

Description Axway SecureTransport is the official Consumers Energy multi-protocol Managed File Transfer (MFT) gateway for securing, managing, and tracking data file flow for business partners and external vendors. Files impacting billing, HR, Supply Chain, Finance, Alternate Energy Programs, Front Office, Back Office, Device Management, Outage Management and Business Reporting functions utilize these services. This project will update the platform to the current software version, enabling cost saving operational enhancements while retaining data security and platform supportability.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement As Axway Secure Transport is the public-facing MTF gateway, maintaining platform version integrity is critical to ensuring it remains secure and supportable in the event of a cyber attack, outage or other critical incident. A prolonged outage or incident, for any reason, compromises the ability of the Company to perform mission-critical business transactions in finance, operations and direct customer support. Upgrading this application also gives the Company the opportunity to properly scale SecureTransport and take advantage of the growing demand for additional, cost-savings features of the tool, such as managing internal Electronic Data Interchange transactions.

Objectives The value this project brings the Company, its customers and business partners by: (1) addressing known problems and limitations of the current software platforms. (2) ensuring continued secure, scalable, and critical data transmission services running through Axway. (3) creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste. (4) merging/streamlining the company data file transfer services reduces cyber attack vectors and creates a better, more easily maintained and monitored security model.

Scope The scope of this project includes (1) upgrading the application and database to the current released and supported versions. and (2) enabling and testing in scope file transfer processes.

Alternatives Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because the Axway SecureTransport platform handles critical Company financial, HR, and operational transactions--the risk associated with problems stemming from an outdated and unsupported version is too high. (2) replacing the platform. The estimated project costs and timetable for replacing the business functions currently performed by the existing Axway SecureTransport platform would be extensive, and operationally, it is not well suited for a SaaS or hybrid cloud solution. In addition to significant platform, application, implementation, and functional testing costs, replacing it would require extensive coordination and testing with all of the internal and external account holders, taking upwards of one calendar year. (3) upgrading the platform. This provides the Company the best, most cost-effective alternative, balancing costs, known risks, and even growing business capacity and productivity.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/1/2027	1/15/2027	2/1/2027	3/15/2027
	In-Service/Go-Live	**Closeout**	
	7/15/2027	8/1/2027	

FUNDING SUMMARY

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.400	-	-	-	-	-	-	-	$0.400
Total Cost of Ownership	$0.400	-	-	-	-	-	-	-	**$0.400**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.374	-	-	-	-	-	-	-	**$0.374**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.026	-	-	-	-	-	-	-	**$0.026**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.400	-	-	-	-	-	-	-	**$0.400**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.400	-	-	-	-	-	-	-	**$0.400**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.400	-	-	-	-	-	-	-	**$0.400**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	An out-of-support version of Secure Transport that Axway no longer provides hotfixes for will put the company network at risk as this is a external (internet) facing application.

OTHER VALUE

Type	Description
Intangibles	Newer versions of Secure Transport will assist in improving performance of the platform through bug fixes and performance tuning.

BizTalk Services Migration and Retirement

Report Pulled: 4/16/2026 **Item ID: 11762**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias BizTalk Upgrade, BizTalk 2025 Upgrade, BizTalk 2026 Upgrade, BizTalk 2025 Upgrade, BizTalk 2025 Migration, BizTalk 2026 Migration, BizTalk 2026 Upgrade, BizTalk 2025 Migration, BizTalk Services Migration and Retirement

Description The Microsoft BizTalk application transfers data from one location to another with internal and external software systems and assists with securely communicating sensitive financial data. The project will migrate the BizTalk application services to other existing applications resulting in the retirement of the Biztalk application

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement Microsoft announcing end of life for this application a replacement is needed to avoid business impact. The current version of Biztalk running at Consumers Energy is already out of mainstream support. if major issues occur within the application, it could disrupt critical business processes. This includes financial concerns such as payroll, account receivable, and other essential operations. Ensuring continuity is vital.

Objectives This project creates and maintains value for the Company and its customers by migrating the Biztalk services to supported applications already present in the Consumers Energy environment that do have not end of life concerns and can provide the same functionality Biztalk was providing to meet business requirements.

Scope This project creates and maintains value for the Company and its customers by: (1) Migrating all current processes from the current application to replacement products. The secure file transport processes will be migrating to the existing Axway Secure Transport platform. The Electronic Data Interchange processes will be migrated to the existing SAP platform. (2) Ensuring current and future compliance with Information Security critical and sensitive data initiatives, such as patching, data encryption, and authentication requirements. (3) Guarantees 7x24x365 vendor support is available to the Company during significant outages by remaining on a version supported by the vendor.

Alternatives Alternatives considered included: (1) Using Azure native services to recreate all of the processes and services Biztalk provided. This was cost prohibitive due to time and effort this would take. (2) Purchasing a replacement product. Not seen as optimal as existing applications are already implemented within Consumers Energy that provide the same capability. (3) Leverage existing applications within the Consumers Energy application portfolio. This option was selected as lowest cost option and also to meet application rationalization goals to eliminate applications that are providing duplicate functionality.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/6/2025	2/15/2025	3/30/2025	4/1/2025
	In-Service/Go-Live	**Closeout**	
	10/18/2025	11/21/2025	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	$0.876	-	-	-	-	-	-	$0.876
O&M	$0.541	$0.390	-	-	-	-	-	-	$0.930
Total Cost of Ownership	$0.541	$1.266	-	-	-	-	-	-	**$1.807**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.528	$1.152	-	-	-	-	-	-	**$1.680**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.013	$0.114	-	-	-	-	-	-	**$0.127**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.541	$1.266	-	-	-	-	-	-	**$1.807**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.541	$0.390	-	-	-	-	-	-	**$0.930**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.541	$0.390	-	-	-	-	-	-	**$0.930**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.876	-	-	-	-	-	-	**$0.876**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.876	-	-	-	-	-	-	**$0.876**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	An out-of-support version of Biztalk that Microsoft no longer provides hotfixes for will put the company network at risk as this is a external (internet) facing application.
Technology Obsolescence	Medium	High	Will have impact from aging infrastructure and application if the work item is not complete

OTHER VALUE

Type	Description

Business Capability Mapping SaaS Tool

Report Pulled: 4/20/2026 **Item ID:** 14014

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Business Capability Mapping SaaS Tool

Description The Business Capability Mapping (BCM) SaaS Tool is a cloud based software solution which will visualize the Company's capabilities related to our metrics, data maturity, supporting technologies, financial allocations, and other view points. The tool will automate analysis and report generation to quickly provide information while supporting other efforts directly supporting technology investment planning and management.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-STRATEGY & GOVERNANCE

WORK OBJECTIVES

Problem Statement The current lack of a centralized tool for tracking enterprise-wide data, which is manually managed via Excel, poses significant challenges. This manual process limits data sharing and the distribution of business capability roadmaps, complicating investment planning and alignment. The absence of a centralized tool also hinders effective communication regarding prioritization and application stack updates, preventing a comprehensive view of impacted areas. Consequently, the enterprise architecture practice struggles to accurately plan and forecast investment opportunities, leading to misallocation of funds, labor, and potential delays in enabling strategic opportunities. The solution will include implementing a centralized tool to streamline data sharing, enhance communication, and support accurate planning and forecasting.

Objectives The company will see value through: (1) Implementing processes and supporting technical components to enable automated scoring of capabilities, including scores, measures, metrics, Key Performance Indicators (KPIs), and Objectives and Key Results (OKRs) for consistent and accurate analysis; (2) Developing a consolidated view of critical capabilities, applications, and infrastructure, ranked based on their efficiency and effectiveness in meeting company objectives; (3) Integrating key technology features supporting Application Rationalization, Enterprise Resource Planning (ERP) system and major platform upgrades, Business Capability Modeling, Application Stack Ownership, Enterprise Architecture Artifact Tool Repository, centralized repository and role based access; (4) Generate a consistent framework to support the prioritization of investments based on their impact on key capabilities across the enterprise; (5) Implement a shared platform to integrate architecture activities versus siloed practices; and (6) Consolidate empirical data used for investments and technical health to ensure accuracy and consistency in evaluations.

Scope The project scope includes: (1) Implement a role-based access SaaS product and integrate with ServiceNow and other internal systems; (2) Configure the SaaS product with identified tools for data gathering on capabilities and their performance; (3) Develop processes and automation to gather data on capabilities, including applications, technical infrastructure, and metrics; (4) Establish a framework for prioritizing investments; (5) Create role-based dashboards and reports to visualize the output of data analysis; (6) Develop automated communications for key business decisions, investment plans, data collection, and reports; (7) Enable self-reporting on data within the tool; (8) Connect supporting documentation to the capabilities; and (9) Provide training on how to use the tool including end-user training.

Alternatives Alternatives considered for this include: (1) Continue with current practices for initiative planning and Enterprise Architecture practices. This was not selected as it does not address gaps in enterprise-wide practices and consolidated roadmap capabilities addressing key company objectives. (2) Develop in-house applications using multiple platforms including Excel, PowerBI, and custom development. This was not selected due to complexity of the solution and cost of delivery. Additionally, the dependency on the automated processes would create additional hurdles for efficient delivery. (3) Acquire external tools to support BCM, Enterprise Architecture, and investment planning. This solution was selected as it provides quick and efficient access to automated tools within acceptable cost ranges.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
4/15/2025	5/30/2026	6/23/2026	7/28/2026
	In-Service/Go-Live	**Closeout**	
	10/17/2026	11/21/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	$0.548	-	-	-	-	-	-	$0.548
O&M	-	$0.421	$0.275	$0.275	-	-	-	-	$0.971
Total Cost of Ownership	-	$0.969	$0.275	$0.275	-	-	-	-	**$1.519**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.500	-	-	-	-	-	-	**$0.500**
Outside Services	-	$0.035	-	-	-	-	-	-	**$0.035**
Business Expense/Overheads	-	$0.434	$0.275	$0.275	-	-	-	-	**$0.984**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.969	$0.275	$0.275	-	-	-	-	**$1.519**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	$(0.375)	$(0.250)	$(0.125)	-	-	-	-	-	**$(0.750)**
	Initial	-	$0.421	$0.275	$0.275	-	-	-	-	**$0.971**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$(0.375)	$0.171	$0.150	$0.275	-	-	-	-	**$0.221**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.548	-	-	-	-	-	-	**$0.548**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.548	-	-	-	-	-	-	**$0.548**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.506

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Application Lifecycle Management - estimated $1.8m in avoided costs if we don't renew 12 apps per year and avoid pursuing 12 apps through more closely aligning application categories to business capabilities and functions.
Intangibles	Improving the planning process and cycles will enable architecture resources to allocate time away from lengthy project spin up activities. Conservative estimate suggests 2 weeks can be re-allocated per resource per project to other activities. Assuming 15 projects per year, this could lead to 30 weeks available for alternate activities.
Risk Mitigation	Reduction in technical debt stemming from applications not being upgraded to stay with current versioning standards. Applications on older versions have more risk of issues, failure points, and security breaches in addition to potential cost increases for maintenance on aging software.
Avoided Costs	Utilizing the software and improved planning process can lead to avoided costs for software maintenance associated with missed upgrades. Reasonable estimate places this at $90k/yr per application including extended maintenance, price increases, and technical debt.

Cascade Modernization and Prioritization

Report Pulled: 4/15/2026 **Item ID: 13433**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Cascade Modernization and Prioritization

Description The project will add additional features and enhancements to Cascade, the High Voltage Distribution (HVD) team's asset management database, which includes HVD line switches, all substation and mobile substation equipment and some Low Voltage Distribution (LVD) equipment. These new capabilities will improve the efficiency, add automation and visualization of these assets.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The Cascade Asset Management Database is currently lacking in two areas. 1) It does not currently have reporting for visual management that will show Asset Health. This results in not being able to prioritize equipment inspections and maintenance which causes wasted effort by operators spending time on the wrong equipment; and 2) integration to the Company's SCADA (Supervisory Control and Data Acquisition) system. Substation Operators inspect substations on a monthly/bi-monthly basis. Inspections require manual data entry that is already being collected by SCADA. Consequently, operators spend more time and effort on inspections focusing on data entry tasks rather than on meaningful inspection of equipment.

Objectives Completion of this project will provide value to the Company through: (1) providing visual management using standard and customizable reports which will allow the Company to make data driven decisions; (2) establishing a link between equipment and SCADA which will allow anomalies to be detected and alerts to be sent to the team. This will automate data collection for substations inspections; and (3) allow visual management to be updated daily to reflect Asset Health status and be able to prioritize maintenance.

Scope The project scope includes: (1) installing the Connect module to Cascade; (2) installing the Insight module to Cascade; (3) securing a connection to the PI Historian server; (4) installing on-premise web server; and (5) creating additional dashboards.

Alternatives Alternatives considered included: (1) Breaking the scope into separate projects to be completed individually. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work efforts resulting in higher costs. (2) Do nothing. This alternative was not selected because the Company is not able to evaluate the equipment to the best of its ability allowing the team to make the best decisions. (3) Combining the work efforts for both initiatives into a single project to realize the most potential. This alternative was selected because it provided the best balance between achieving the project objectives and controlling the cost. Installing both solutions will allow visual management to be updated daily to reflect Asset Health status and the ability to prioritize maintenance.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
6/5/2024	7/11/2024	8/8/2024	1/23/2025
	In-Service/Go-Live	**Closeout**	
	2/20/2025	3/27/2025	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.287	$0.232	-	-	-	-	-	-	$0.519
O&M	$0.006	$0.035	$0.052	$0.052	$0.001	-	-	-	$0.146
Total Cost of Ownership	$0.293	$0.267	$0.052	$0.052	$0.001	-	-	-	**$0.665**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.021	$0.184	-	-	-	-	-	-	**$0.205**
Outside Services	$0.264	$(0.177)	-	-	-	-	-	-	**$0.087**
Business Expense/Overheads	$0.008	$0.041	-	-	-	-	-	-	**$0.049**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.219	$0.051	$0.051	-	-	-	-	**$0.322**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.293	$0.267	$0.051	$0.051	-	-	-	-	**$0.663**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	$(0.479)	$(0.479)	-	-	-	-	-	-	**$(0.958)**
	Initial	$0.006	$0.035	$0.052	$0.052	$0.001	-	-	-	**$0.146**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$(0.473)	$(0.444)	$0.052	$0.052	$0.001	-	-	-	**$(0.812)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.287	$0.232	-	-	-	-	-	-	**$0.519**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.287	$0.232	-	-	-	-	-	-	**$0.519**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	0.291

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	$957,660 - By removing manual reads, inspections could be reduced by roughly 1 hour per substation due to the SCADA data being available in Cascade with this project. 1 hour saved, 8,706 inspections annually, $110/hour.
Intangibles	Currently, substation inspections occur on a monthly or bi-monthly basis. This project will automate pulling SCADA on a daily basis for the algorithms within Cascade to update asset health risk scores.
Intangibles	This project will reduce human struggle due to being able to visualize, prioritize, and maintain asset health information. Asset health data will be automated to display on dashboards for decision making based on risk prioritization.

Catastrophic Crewing (CatCrew) Version 2.0

Report Pulled: 4/15/2026 **Item ID:** 12558

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Catastrophic Crewing Database Replacement, Catastrophic Crewing (CatCrew) Version 2.0

Description The Catastrophic Crewing (Cat Crew) Version 2.0, formerly known as Catastrophic Crewing Database Replacement, will significantly overhaul and enhance the Catastrophic Crewing application, which is the software used during storms to manage storm resources and logistics, as well as key pieces of equipment during storm restoration.

Portfolio Electric Delivery Systems > Electric Operations > Emergent Repair Funds > Emergent Repair Funds > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The current features of the Catastrophic Crewing are not meeting the continually changing expectations and the enhancement update timeline will not allow for timely upgrades to be implemented in the current system - approximate timeframe is 2025-2028 for any changes or additional functionality. We are unable to see and track resources or storm data accurately. There is a significant amount of manual processes: which include hotel reservations tasks, external crews assignments, and ICS on-call schedules that need weekly identification and analysis. There is an opportunity for approximately 4,000 hours of automation annually identified from these processes. The current system is not easy to use or intuitive. The data and reporting history is not accurate or up to date. There is significant potential for human error in the current system, which in turn creates a large volume of waste and increases possible risk to the public and field crews.

Objectives The project will add value by: (1) streamlining the procurement of internal and external resources during storm conditions; (2) providing accurate information regarding hazard conditions and resource deficiencies; (3) enabling real time updates and safety visibility of all resources in the field; (4) reducing human struggle with office and field resourcing tasks; (5) improving reporting accuracy and reducing troubleshooting and data validation; and (6) improving resource management.

Scope The project scope includes: (1) identifying requirements for Catastrophic Crewing replacement; (2) developing, configuring, and testing interfaces, hardware, and software for the solution; (3) implementing the solution and process for the following work groups: Electric High-Voltage Distribution (HVD), Electric Low-Voltage Distribution (LVD), Mutual Assistance, Forestry, Restoration Management, and Storm Teams; (4) change management; (5) building system controls for validating that all required data entry is entered; (6) enhanced logic to automate callout for storm responders; (7) enhancing database exporting and reporting functionality; (8) error-proofing entries for all resources through data validation in the application; (9) archiving all resource data; (10) implementing functionality to identify the status of Forestry, Damage Assessment, Wire Down, and all other field resources in each area; (11) training resources on new technology and processes; and (12) automation of lodging capabilities for crews.

Alternatives The alternatives considered included: (1) continuing with the current system and processes. This alternative was not selected because it does not allow for the timely, data-driven management of resources required to improve service to customers and safety of our field resources; (2) a complete overhaul and enhancement of current system. This alternative was not selected because it is not expected to receive long term and timely enhancements to the platform, which would also require significant upfront investment and internal resource allocation; (3) Dividing the scope into separate projects to be completed individually. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work efforts, and therefore potentially higher costs; and (4) replacing the current system with a system that is capable of new functionality that will remedy the issues with the current system. This alternative was selected because it minimizes duplication of efforts; maximizes identified benefits in operating and cost savings; and increases management of project costs.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/1/2024	5/31/2024	7/31/2024	1/15/2025
	In-Service/Go-Live	**Closeout**	
	3/14/2026	4/1/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.695	$1.758	$0.490	-	-	-	-	-	$2.944
O&M	$0.031	$0.005	$0.086	$0.300	$0.300	$0.300	-	-	$1.022
Total Cost of Ownership	$0.726	$1.764	$0.576	$0.300	$0.300	$0.300	-	-	**$3.966**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.186	$1.458	$0.400	-	-	-	-	-	**$2.044**
Outside Services	$0.486	-	-	-	-	-	-	-	**$0.486**
Business Expense/Overheads	$0.054	$0.287	$0.176	-	-	-	-	-	**$0.517**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.019	-	-	-	-	-	-	**$0.019**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.726	$1.764	$0.576	-	-	-	-	-	**$3.066**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	$(3.735)	$(4.981)	$(4.981)	$(4.981)	$(1.245)	-	**$(19.922)**
	Initial	$0.031	$0.005	$0.086	$0.300	$0.300	$0.300	-	-	**$1.022**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.031	$0.005	$(3.650)	$(4.681)	$(4.681)	$(4.681)	$(1.245)	-	**$(18.901)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.695	$1.758	$0.490	-	-	-	-	-	**$2.944**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.695	$1.758	$0.490	-	-	-	-	-	**$2.944**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	2.880

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	PERFORMANCE METRIC: System Average Interruption Duration Index (SAIDI) Improvement of customer outage minutes from 2352.1 to 2307.43. For a decrease of 44.67 minutes (2%).
Risk Mitigation	This project will make a significant impact to risk management, specifically life safety of Consumers Energy field personnel. There were three confirmed Stop the Jobs (STJ) in 2021 associated with potential energization on tree crews actively working on circuits in the areas being energized. This project enables full visibility of all field resources including forestry, damage assessment, wire down personnel, field leaders, contract crews, and internal crews within a single platform. This enhancement would allow Consumers Energy to eliminate these STJ events based on the new functionality within the platform.

Critical Substation Upgrade

Report Pulled: 4/15/2026 **Item ID: 13388**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Critical Substation Upgrade

Description This project will implement enhanced security measures at the Company's critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time. With the enhanced security posture, Consumers Energy will be better positioned to mitigate malicious activity through real-time detection and increase the reliability of electric delivery to our customers.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CORPORATE SECURITY

WORK OBJECTIVES

Problem Statement Today, Consumers Energy currently deems 16 substations as business critical to its electric system while an additional 34 substations fall under NERC-CIP compliance. Recent attacks to critical infrastructure have increased the likelihood of an adversary exploiting vulnerabilities at critical substation increasing the risk for large scale outages and customer impact. The Company's current security measures do not allow us to detect, deter, or monitor potential threats on site. Without the ability to monitor these assets in real-time, the Company is vulnerable to an adversary causing destruction without knowledge of when or how the event took place. A phased implementation would allow the Company to systematically mitigate risk to assets deemed most vulnerable.

Objectives The objective of this project is to implement enhanced security measures to better detect, deter, and respond to threats to the Company's electric substations in real-time. This enhanced security posture will align with other utilities that own and operate substations and mitigate disruption to electric service while improving reliability.

Scope Enhanced Security measures that will need to be implemented include but are not limited to: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fence intrusion (which will be accomplished through camera systems); (6) subcontractor work of trenching poles, installing equipment etc.; (7) additional facility lighting; and (8) security equipment maintenance.

Alternatives Alternatives considered include: (1) maintaining the current security perimeter fencing and conducting routine inspections of the site. This alternative was not selected, as it does not provide the ability to prevent, detect, or respond to threats in real-time; (2) hiring contract security guards to patrol the sites. This alternative was not selected as ongoing O&M costs would be expensive; (3) outfitting sites with thermal cameras with built in analytics that would alarm to intrusions and subjects on the properties along with access control measures. This alternative was selected because of lower ongoing O&M costs and enhanced detection abilities.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/1/2026	2/15/2026	4/30/2026	10/31/2028
	In-Service/Go-Live	**Closeout**	
	11/1/2028	11/30/2028	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	$2.757	$4.585	$4.585	-	-	-	-	$11.928
O&M	-	$0.268	$0.375	$0.375	-	-	-	-	$1.017
Total Cost of Ownership	-	$3.025	$4.960	$4.960	-	-	-	-	**$12.944**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.750	$1.350	$1.350	-	-	-	-	**$3.450**
Outside Services	-	$0.563	$0.563	$0.563	-	-	-	-	**$1.688**
Business Expense/Overheads	-	$0.400	$0.735	$0.735	-	-	-	-	**$1.869**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$1.313	$2.313	$2.313	-	-	-	-	**$5.938**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$3.025	$4.960	$4.960	-	-	-	-	**$12.944**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.268	$0.375	$0.375	-	-	-	-	**$1.017**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.268	$0.375	$0.375	-	-	-	-	**$1.017**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$2.757	$4.585	$4.585	-	-	-	-	**$11.928**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$2.757	$4.585	$4.585	-	-	-	-	**$11.928**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Completing this project will help prevent the risk of a major grid outage if multiple substations are attacked at the same time. This project will provide intelligence to avoid attacks on substations that have been happening throughout the country, as documented in the 2025 Homeland Security Threat Assessment.
Risk Mitigation	Completing this project will prevent substation outages due to unauthorized access to substations throughout the state. These outages could affect critical facilities such as hospitals and government facilities, as well as, residential buildings. If the damage is extensive, these buildings could be affected by an extended outage.
Risk Mitigation	Completing this project will protect both employee and public safety since the Company will implement access readers, access controls, cameras and video/audio programming, additional facility lighting and security equipment.

Customer Consecutive Estimate Reduction Enablement

Report Pulled: 4/20/2026 **Item ID:** 14017

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - One Time **Work Type** Project

Alias , ELECTRIC DISCONNECT AND MOVE OUT PROCESS ASSOCIATED WITH CONSECUTIVE ESTIMATES PROBLEM SOLVING CAPA, ELECTRIC DISCONNECT AND MOVE OUT PROCESS ASSOCIATED WITH CONSECUTIVE ESTIMATES, Electric and Gas Disconect and Move Out Process associated with Consecutive Estimates, Electric and Gas Disconnect and

Description The project will resolve gas and electric accounts with consecutive estimates due to the service being disconnected and customer's usage being estimated.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement Consumers Energy experienced two show cause orders from MPSC for consecutive estimates and fines of $500,000 in 2016 and $1 million in 2023. There is also $3 million that is to be refunded to the customers from the money that is recovered from the vendor. If the funding is not recovered from the vendor, the total fine would result in $4 million as the Company is responsible for the difference between the dollars recovered from the vendor and the $3 million total established by MPSC.

Objectives The project objective is to reduce disconnected consecutive estimate accounts from 8% to less than 1% reducing non-compliance regulatory risk with MPSC rules.

Scope The project scope includes enhancing account and work management digital solutions to properly reflect disconnected account status.

Alternatives Process improvements were put into place after the 2016 show cause; however, increased electric meter failures, supply chain shortages, and a project focused on replacing meter technology due to the sunset of 3G communication led to issues that resulted in a second show cause order. Do nothing does not improve the customer experience. Our current solution of SAP CRM used by Call Center, SAP Work Management, ADMS for Storm and Service Suite for Field Work are all core platforms able to accomodate the change. Adding additional software or alternatives will complicate the technical solution and/or require additional training for Call Center & field personnel.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
4/1/2025	4/30/2025	6/30/2025	1/30/2026
	In-Service/Go-Live	**Closeout**	
	2/19/2026	3/5/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.070	$0.642	-	-	-	-	-	-	$0.712
O&M	$0.034	$0.062	-	-	-	-	-	-	$0.096
Total Cost of Ownership	$0.104	$0.704	-	-	-	-	-	-	**$0.808**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.098	$0.625	-	-	-	-	-	-	**$0.723**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.006	$0.079	-	-	-	-	-	-	**$0.085**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.104	$0.704	-	-	-	-	-	-	**$0.808**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	$(0.392)	-	-	-	-	-	-	-	**$(0.392)**
	Initial	$0.034	$0.062	-	-	-	-	-	-	**$0.096**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$(0.358)	$0.062	-	-	-	-	-	-	**$(0.296)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.070	$0.642	-	-	-	-	-	-	**$0.712**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.070	$0.642	-	-	-	-	-	-	**$0.712**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.562

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	10 minutes per creation of storm disconnect, dispatching from pending screen, and completing of the work order. Year to date since implementation of the new data analytics application there were 150 storm disconnect requests processed over the course of 6 months. This does not include requests processed by Dispatch or other departments that are not easily tracked. 0.17 hrs/order * 150 orders/half a year * 2 * 35 $/hour = $2k Though these savings are small due to limited data tracking, the frustration from Electric Field Operations with having to call Dispatch, wait for the order, or go into an application that is not part of the standard technology would be a significant positive impact to morale for both Electric Field Operations and Dispatch.
Avoided Costs	Contact Center completes 15 installation corrections per day. This task takes approximately 15 minutes per order. 15 installations/day * 0.25 hours/order * 38 $/hour * 260 days/year = $37k in efficiency
Avoided Costs	Electric Meter Operations Supervisor completes 16 hours of review and follow up on consecutive estimate accounts. Exempt labor rate of $55 per hour. 16 hours/week * 52 weeks/year * 55 $/hour = $46k in efficiency allowing the Field Supervisor to be more present in the field for employee safety and job oversight
Avoided Costs	Revenue Recovery and Meter Reading complete 56 hours of investigation per week. Assuming exempt labor rate of $35 per hour. There is also IT labor for running the report that is not accounted in these savings. 56 hours/week * 52 weeks/year * 35 $/hour = $102k in efficiency

Customer Order Service Tracker

Report Pulled: 4/14/2026 **Item ID: 9062**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Service Tracker, Customer Order Service Tracker

Description Short cycle orders including gas emergencies and meter services account for many of the incoming customer inquiries to the contact centers. This project will implement a service order status tracker to provide transparency to customers and oversight to internal teams supporting utility service orders across Company service areas. The tracker will provide timely and accurate service order updates, creating a more robust customer experience for tracking service order status and location-based updates.

Portfolio Customer Services > Customer Interaction Channels > Digital > Digital > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement Customers have limited visibility to when Company assigned crews will be on premise and what work will be completed. This is due to features missing within the Company's digital channels for accurate updates from dispatch, scheduling, and field crews. The lack of awareness drives calls into the call center, resulting in approximately 346,000 annual contact center calls related to short cycle requests. Additionally, this lack of visibility increases truck rolls due to dispatchers being unaware of crew locations and routes which can cause crews to be assigned when a local crew could have completed the work. This leads to overall customer dissatisfaction because of a lack of visibility to scheduled and ongoing short cycle work. Enabling a digital channel for communication regarding utility service orders will improve customer experience and reduce the waste of repetitive crew dispatching.

Objectives This project will add value to the Company and its customers by: (1) providing transparency for customers on the timing and location of the associated crew completing utility short cycle service orders, (2) reducing calls to contact centers by customers seeking clarification regarding arrival times through visibility to scheduling time-frames and providing notifications to customers when crews are en-route, (3) improving resource assignment by current location, which decreases wasted truck rolls through enabling location services for active crews, (4) increasing visibility into the service person(s) completing the order by enabling crews to connect with customers through digital channels, and (5) improving customer experience for short cycle service orders by implementing a channel of choice for Company interactions.

Scope The scope for the project includes: (1) modifying the customer self-service portal to include features that support utility service order tracking, including the location of crews en-route, (2) providing desktop and mobile capabilities, (3) enhancing the existing ServiceBench platform to allow real-time status updates that can be communicated to customers, (4) utilizing location-based services to update internal portal in real time, and (5) enabling text and email notifications to alert customers of service crews arrival times.

Alternatives Alternatives considered for this project include: (1) Deploy a mobile application to address utility service order tracking, (2) utilize a cloud hosted solution from a third-party, (3) modify the existing customer portal to enable customers and the Company to track utility service orders and crews. Options one and two were not selected as the cost associated with deployment would greatly outweigh the benefits with call reduction and improved customer experience. The third option was selected because it utilizes existing technologies, which reduces the implementation complexity and project cost and has faster value realization for the customer and the Company.

DATES (phase end)

Initiation 1/10/2025	**Project Plan & Scope Definition** 4/11/2025	**Final Engineering, Planning & Design** 6/13/2025	**Execution** 6/26/2026
	In-Service/Go-Live 8/28/2026	**Closeout** 11/20/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$0.567	$2.815	-	-	-	-	-	$3.382
O&M	-	$0.206	$0.655	$0.050	$0.050	$0.050	$0.050	$0.050	$1.111
Total Cost of Ownership	-	$0.773	$3.470	$0.050	$0.050	$0.050	$0.050	$0.050	**$4.493**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.016	$1.050	-	-	-	-	-	**$1.066**
Outside Services	-	$0.511	$1.400	$0.050	$0.050	$0.050	$0.050	$0.050	**$2.161**
Business Expense/Overheads	-	$0.006	$1.020	-	-	-	-	-	**$1.026**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.240	-	-	-	-	-	-	**$0.240**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.773	$3.470	$0.050	$0.050	$0.050	$0.050	$0.050	**$4.493**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.206	$0.655	$0.050	$0.050	$0.050	$0.050	$0.050	**$1.111**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.206	$0.655	$0.050	$0.050	$0.050	$0.050	$0.050	**$1.111**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.567	$2.815	-	-	-	-	-	**$3.382**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.567	$2.815	-	-	-	-	-	**$3.382**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Improve safety for both the Company's employees and customers by providing accurate estimated times of arrival, reducing the likelihood of threats of violence.
Intangibles	Improved customer experience related to real time updates from service crews completing activities in their area. The crews will have the ability to provide accurate estimated times of arrival and detail what work is being completed via digital channels. Building trust between the Company and its customers regarding the work being completed correctly, the first time a crew arrives.
Avoided Costs	Reduce Truck Rolls for appointments that weren't rescheduled in a timely manner and limiting truck rolls in locations where a crew can complete multiple jobs in a geographic location. Each avoided truck roll saves the company approximately $450.
Avoided Costs	Reduction in calls to validate arrival times of field crews based on more clarity and transparency regarding the service being completed. Currently 346,000 calls take place yearly regarding status of service orders. The project anticipates a 60% reduction over three years resulting in potential avoided costs of $537,996 per year. (Avg cost per call $7.63 [$9.76/call internal & $5.50/call H&H] * 69,000 calls reduced each year.)
Intangibles	Reduction in Customer Complaints regarding service orders, delays in service, and maintenance visits. Last year, the company received 6 formal complaints and 11 informal complaints regarding non-emergency maintenance work.

Data & Analytics Platform Rationalization

Report Pulled: 4/15/2026 **Item ID:** 13961

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Data & Analytics Platform Rationalization

Description This project will optimize the Data & Analytics system landscape by creating connections, migrating data into the Data Lake in the cloud, and building visualizations from the data in the Data Lake.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement The IT Data & Analytics legacy systems (SingleStore Datalake (SSDL), SAP Business Warehouse (SAP BW), SAP Business Objects (SAP BOBJ), Native HANA, the SAP BW Portal, and BusinessObjects Data Services BODS)) are outdated, inefficient, and becoming duplicative in nature with the introduction of DL 2.0. If these legacy systems are not retired, they will continue to cost the Company money as major investments are needed to maintain and support them.

Objectives This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources.

Scope The project scope includes: (1) the assessment of the existing Data & Analytics platforms including SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organization change management; and (7) the retirement/decommissioning of the legacy platforms and applications.

Alternatives Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company's cloud strategy. (2) Lift and shift these on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces. (3) Migrate all data sources to DL 2.0 and retire legacy systems. This alternative was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
3/3/2025	4/28/2025	5/30/2025	7/28/2027
	In-Service/Go-Live	**Closeout**	
	8/14/2027	9/18/2027	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$1.712	$4.005	$3.303	-	-	-	-	-	$9.020
O&M	$0.033	$0.651	$0.588	-	-	-	-	-	$1.272
Total Cost of Ownership	$1.745	$4.656	$3.891	-	-	-	-	-	**$10.292**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$1.004	$2.787	$0.993	-	-	-	-	-	**$4.784**
Outside Services	$0.547	$1.500	$1.846	-	-	-	-	-	**$3.893**
Business Expense/Overheads	$0.194	$0.368	$0.688	-	-	-	-	-	**$1.251**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	$0.364	-	-	-	-	-	**$0.364**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.745	$4.656	$3.891	-	-	-	-	-	**$10.292**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	$(0.610)	$(3.028)	$(2.427)	$(2.436)	$(2.445)	$(2.454)	-	-	**$(13.399)**
	Initial	$0.033	$0.651	$0.588	-	-	-	-	-	**$1.272**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$(0.577)	$(2.377)	$(1.838)	$(2.436)	$(2.445)	$(2.454)	-	-	**$(12.127)**
Cap+COR	Reduction	$(0.300)	-	$(2.000)	$(2.000)	-	-	-	-	**$(4.300)**
	Initial	$1.712	$4.005	$3.303	-	-	-	-	-	**$9.020**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.412	$4.005	$1.303	$(2.000)	-	-	-	-	**$4.720**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	0.432

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Attraction and Retention of High Performing En	Medium	Medium	By retiring legacy systems and shifting to industry leading technologies (Microsoft Azure), the Company can attract and retain talent.
Inaccuracy of Financial and Operational Reporti	Medium	High	Due to limitations with legacy systems, system outages will continue to happen regularly which impact reporting metrics for many areas across the organization including potential impacts to month end close and Operations operating review metrics. As of May 2024, there have been six SAP BW/SAP BOBJ outages that impacted critical reporting.

OTHER VALUE

Type	Description

Digital-Cloud Data and Analytics Platform

Report Pulled: 4/15/2026 **Item ID:** 13443

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Accelerate Data Strategy, Digital-Cloud Data and Analytics Platform

Description This project will provide Artificial Intelligence (AI) and analytics in the cloud across the business to uncover new paths to value, faster, allowing the organization to make better decisions and enable delivery outcomes for the NGDP, Electric Grid Integration, customer programs, and other business needs. The project will additionally establish data governance roles and responsibilities, processes, and implement tools to support best practices across the enterprise.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement Consumers Energy faces several challenges in the ongoing data modernization journey, which include: (1) legacy data platform operations; (2) long lead times for data exploration and identification of data assets; (3) lack of data ownership and quality, (4) limited data governance best practices across data ownership, access control & security; and (5) heavy dependence on IT for Business Intelligence reporting and analytics.

Objectives The project will add value by providing data to support business needs by: (1) optimizing data platform operations costs with workflow-based platform infrastructure deployment using pre-built modules and templates; (2) reducing data operations build complexity and data engineering costs through automation; (3) improving data quality and governance that leads to reduced costs of data provisioning, data duplication, and improved data accuracy; (4) streamlining data access requests, management, and governance to reduce risks and support efficiency; and (5) increasing the speed to deliver new data and data capabilities, improving productivity, and improving access to data. This project is an enabler for business areas to use these capabilities to build analytic models for asset and labor optimization that is anticipated to more than offset the project costs.

Scope The project scope includes: (1) developing and modernizing the analytics platform in the cloud to allow Consumers Energy to implement new use cases leveraging simplified infrastructure configurations and automated deployment processes; (2) build and deploy data management capabilities, controls, catalog, assets, and data flow; (3) developing data ordering workflows and data access management controls; (4) prioritization and new datasets; (5) simplifying infrastructure configuration; (6) automating deployment processes; (7) enabling data governance tools and processes.

Alternatives Alternatives considered include: (1) Address current pain points in existing on-premise and cloud analytics platforms. This alternative was not selected because the existing platforms requires new investment in licensing and infrastructure, delivery for new capabilities cannot keep pace with demand, still requires investment to address legacy system technical obsolescence, and business areas would not realize asset and labor optimizations. (2) Continue to utilize existing on-premise and cloud analytics platforms. This alternative was not selected because it would not address the current pain points in the existing on-premise and cloud analytics platforms, limiting the Company's ability to have required data and analytics capabilities to improve processes and realize asset and labor optimizations. (3) Implement a new data and analytics platform in the cloud. This alternative was selected because it provides improved analytics capabilities, faster access to data that is critical to improve business process, and reduces technical obsolescence.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
5/1/2023	5/1/2023	6/5/2023	7/31/2023
	In-Service/Go-Live	**Closeout**	
	7/31/2023	12/6/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$3.342	$9.027	$(0.115)	-	-	-	-	-	$12.254
O&M	$0.197	$1.062	$0.047	$1.588	$1.588	-	-	-	$4.483
Total Cost of Ownership	$3.539	$10.089	$(0.068)	$1.588	$1.588	-	-	-	**$16.736**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.726	$1.298	$0.018	-	-	-	-	-	**$2.041**
Outside Services	$1.912	$7.906	$(0.264)	-	-	-	-	-	**$9.555**
Business Expense/Overheads	$0.253	$0.408	$0.001	$0.084	$0.084	-	-	-	**$0.831**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.118	-	-	-	-	-	-	**$0.118**
Licenses, Permits & Fees	$0.648	$0.358	$0.177	-	-	-	-	-	**$1.184**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.539	$10.089	$(0.068)	$0.084	$0.084	-	-	-	**$13.729**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.197	$1.062	$0.047	$1.588	$1.588	-	-	-	**$4.483**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.197	$1.062	$0.047	$1.588	$1.588	-	-	-	**$4.483**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$3.342	$9.027	$(0.115)	-	-	-	-	-	**$12.254**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$3.342	$9.027	$(0.115)	-	-	-	-	-	**$12.254**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Automated deployments for infrastructure decreases build time and increases time spent on higher value work for the IT platform team. This will also decrease future project implementation hours and associated labor costs. Avoided benefits will be finalized following phase 1.
Intangibles	Enhance Workplace Productivity and Collaboration: Improve Analytics Efficacy and time to insights with data catalog and data democratization.
Risk Mitigation	Reduce Data compliance Risk and Exposure: Reduced exposure to data loss, compliance risk, or potential for data platform interruption with integrated data catalog, controls and governance.

Digital-Hybrid Cloud and Data Center Migration

Report Pulled: 4/15/2026 **Item ID:** 10502

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Hybrid Cloud and Data Center Migration, Digital - Hybrid Cloud and Data Center Migration, Digital-Hybrid Cloud and Data Center Migration

Description This project will optimize data center assets and asset replacement project purchases by migrating or retiring applications out of existing Company and co-location data centers into cloud services, reducing operational costs for running IT services and leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS & S

WORK OBJECTIVES

Problem Statement The technology currently deployed in the Company's data centers meets many customers' needs today. However, the pace of digital transformation is increasing rapidly, and requirements for applications are evolving faster than the technology in the Company's data centers can respond in a cost-effective manner. These data center constraints lead to longer implementation times, missing capabilities, or reduced functionality in the applications that the Company can deploy.

Objectives This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective combination of data centers and public cloud services. Specifically, by migrating applications to cloud services, the project will: (1) reduce capacity, hardware maintenance, and security device costs at the co-location data center; (2) reduce hardware maintenance and security device costs at the production data center; (3) enable the ability to scale infrastructure quickly up or down without costly up-front hardware purchases; (4) reduce application risk through cost-effective, scalable infrastructure redundancy and availability; (5) reduce ongoing server and storage asset replacement costs; (6) reduce ongoing networking equipment replacement costs; (7) reduce operational support costs; and (8) enable the use of a vast array of cloud services to support Company applications.

Scope The project scope includes: (1) promoting the robust main co-location data center to become the primary data center for on-premise IT services; (2) demoting the Company's production data center to the disaster recovery data center for on-premise IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premise to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying base infrastructure to allow each location (on-premise or in cloud) to function independently; (7) deploying cloud and on-premise cost management tooling and processes; (8) simplifying and optimizing backup and disaster recovery resources and processes using cloud services; (9) implementing additional automation for application deployment and management; (10) changing the operations model for support of cloud-based applications; (11) educating and increasing the skills of IT and other employees on leveraging public cloud services; and (12) transforming IT to become the broker of cloud services for the Company.

Alternatives Alternatives considered include: (1) migrating to public cloud services faster. This alternative was not chosen because the Company's ability to absorb new technologies coupled with the investments the Company has already made in data center equipment would prevent a faster move from being efficient and effective, introducing additional financial risk; (2) migrating to public cloud services slower or not at all. This alternative was not selected because delaying public cloud services and capabilities coupled with requiring an extension of the life of existing data center equipment creates increased financial and operational risk; and (3) contracting with an outside vendor to provide cloud services to run applications for the Company. This alternative was not selected because industry information shows the option as not yet cost effective or not providing a maturity level that the Company would be able to easily consume with limited in-house experience and expertise in public cloud. The alternative to migrate to a hybrid cloud and data center model was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/1/2023	4/15/2023	8/15/2023	10/1/2026
	In-Service/Go-Live	**Closeout**	
	12/1/2026	12/15/2026	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	$2.779	$2.425	$3.977	$0.613	-	-	-	$9.793
O&M	-	$0.529	$0.783	$0.854	$0.161	$11.454	$11.354	$25.707	$50.841
Total Cost of Ownership	-	$3.308	$3.207	$4.831	$0.773	$11.454	$11.354	$25.707	**$60.635**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	-	$0.372	$1.004	$3.955	$0.550	-	-	-	**$5.880**
Outside Services	-	$1.062	$1.760	$0.014	-	-	-	-	**$2.836**
Business Expense/Overheads	-	$0.157	$0.222	$0.446	$0.223	-	-	-	**$1.048**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.379	$(0.074)	$(0.003)	-	-	-	-	**$0.301**
Licenses, Permits & Fees	-	$1.339	$0.296	$0.420	-	$1.100	-	-	**$3.155**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$3.308	$3.207	$4.831	$0.773	$1.100	-	-	**$13.220**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	$(0.623)	$(1.382)	$(4.223)	$(6.008)	$(6.188)	$(6.374)	$(12.068)	**$(36.866)**
	Initial	-	$0.529	$0.783	$0.854	$0.161	$11.454	$11.354	$25.707	**$50.841**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$(0.094)	$(0.600)	$(3.369)	$(5.847)	$5.266	$4.980	$13.639	**$13.975**
Cap+COR	Reduction	-	$(5.624)	$(2.677)	$(3.155)	$(5.820)	$(5.995)	$(4.175)	$(12.910)	**$(40.356)**
	Initial	-	$2.779	$2.425	$3.977	$0.613	-	-	-	**$9.793**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$(2.845)	$(0.252)	$0.822	$(5.207)	$(5.995)	$(4.175)	$(12.910)	**$(30.562)**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) 0.369

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Consumption of public cloud services offers infrastructure redundancy and availability at scale that cannot be duplicated in the Company's data centers, reducing the risk of running applications.
Intangibles	This project makes consumption of all types of public cloud resources possible to provide IT services in support of all business processes, enabling technology capabilities for Administrative and General Support.
Avoided Costs	With applications running in public cloud, the Company can expand and contract the consumption of IT services at will as appropriate versus purchasing hardware to expand in quantity and having no simple ability to contract.

Electric Geographic Information System (GIS) Design Platform M

Report Pulled: 4/15/2026 **Item ID:** 13444

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias GIS-Integrated Design, GIS Integrated Design Application, GIS-Integrated Design, geoAIM Based Design, Electric Geographic Information System (GIS) Design Platform Modernization

Description This project will replace the existing design software for Electric Low Voltage Distribution (LVD) with a new solution that will be fully integrated to the ESRI (Environmental Systems Research Institute) GIS (Geographic Information System) platform which is already in use by the Company. This new solution will leverage GIS asset data to generate engineering designs. This will allow the Electric teams to have a single source and format to view asset data, construction drawings and redlines in both the back office and field. This change will further enable improvements to the mobile platform in quality of data that is used by the closeout team. This will also reduce the back end posting effort by using the native GIS data format; improving data quality by reducing the re-keying of data.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The current design software creates waste in three areas for many teams within Electric including Low Voltage Distribution (LVD) Engineering, Field Leaders, and Customer Energy Management (CEM) Service Designers. (1) The current software does not support the native GIS data format and will not support future enabling work management needs. This causes waste and room for error by having to redraw designs in GIS that have already been created and prevents optimization of the work process. (2) It is not able to integrate to SAP to automatically order materials based on the design. (3) The current software lacks needed mobile functionality due to its lack of support for the native GIS format. The designs are not georeferenced to the exact location and can't fully utilize redlining capability which causes a significant impact to data quality and crew performance.

Objectives This project will add value to the Company and its employees through: (1) eliminating the need to duplicate all design work so it is in both the design system and GIS; (2) enabling mobile editing and redlining on the design in GIS; (3) enabled integration to SAP; and (4) utilizing the capabilities of the next generation GIS platform that will be delivered through an in-progress business case.

Scope The project scope includes: (1) installing a new solution that will integrate to GIS; (2) utilizing GIS geospatial and asset information data and the GIS platform for generating Electric LVD engineering designs; (3) integrating to and from SAP to automate Compatible and Mass Unit material ordering capability; (4) installing new and upgrading existing geospatial platform infrastructure to support additional users (Electric LVD designers, Field Leaders, Planners, Schedulers, etc) of GIS; (5) integrating to ProjectWise (engineering content management system); (6) configuring mobile toolset; (7) re-engineering the existing GIS data model to handle asset life cycle; and (8) configuration for new ArcGIS services.

Alternatives

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
10/24/2025	2/24/2026	2/1/2027	1/25/2029
	In-Service/Go-Live	**Closeout**	
	2/22/2029	3/25/2029	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	$2.278	$2.576	$1.110	$0.277	-	-	-	$6.242
O&M	$0.001	$0.351	$0.137	$0.137	$0.034	$1.140	$1.140	$0.040	$2.980
Total Cost of Ownership	$0.001	$2.629	$2.713	$1.247	$0.312	$1.140	$1.140	$0.040	**$9.221**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.001	$1.178	$1.116	$0.852	$0.213	-	-	-	**$3.360**
Outside Services	-	$0.500	-	-	-	-	-	-	**$0.500**
Business Expense/Overheads	$0.000	$0.681	$0.497	$0.394	$0.099	-	-	-	**$1.671**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.270	-	-	-	-	-	-	**$0.270**
Licenses, Permits & Fees	-	-	$1.100	-	-	$1.100	$1.100	-	**$3.300**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.001	$2.629	$2.713	$1.247	$0.312	$1.100	$1.100	-	**$9.101**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	$(2.085)	$(2.085)	$(2.085)	-	**$(6.255)**
	Initial	$0.001	$0.351	$0.137	$0.137	$0.034	$1.140	$1.140	$0.040	**$2.980**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.001	$0.351	$0.137	$0.137	$(2.051)	$(0.945)	$(0.945)	$0.040	**$(3.275)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$2.278	$2.576	$1.110	$0.277	-	-	-	**$6.242**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$2.278	$2.576	$1.110	$0.277	-	-	-	**$6.242**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.475

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	60% license reduction for current software. Based on 7% increase annually (using 2021 license costs). 2029 savings: $628k, 2030 savings: $672k, 2031 savings: $719k savings
Avoided Costs	Reduction of "overlapping" designs, work orders, truck rolls to the same location: 1,920 hrs ($50) = $96K

Electric GIS Utility Network Transformation

Report Pulled: 4/15/2026 **Item ID:** 14022

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Gas GIS Utility Network Platform Migration, Gas GIS Utility Network and UPDM Platform Migration, Gas GIS Utility Network and UPDM Platform Transformation, Electric GIS Utility Network and UPDM Platform Transformation, Electric GIS Utility Network Transformation

Description This project will transform the Company's current Geographic Information System (GIS) platform to the Environmental Systems Research Institute (ESRI) Utility Network Model and establish a unified high voltage distribution (HVD), low voltage distribution (LVD), and substations data model. This transformation aims to optimize core engineering and operational processes, technologies, and data.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The Company's GIS for electric records is expanding as an authoritative source for asset connectivity, location and health information. However, growing business requirements for advanced analytics and regulatory mandates necessitate more granular geospatial insights. Existing functionality does not meet business partner needs, and GIS data is refreshed in batch mode once a day, leading to mismatches with real-time systems. Managing HVD and LVD data in different models remains challenging. The Company's past implementation of ESRI's GIS for Electric, version 10.8.1, will be unsupported after March 1, 2028. Critical third-party solutions supporting key editing and business functionality are also ending support without upgrade options, posing risks for security updates. ESRI's development focus is shifting to the ArcGIS Utility Network Management extension, ArcGIS Enterprise, and ArcGIS Pro. The vendor's development team has reached the limits of ArcMap and the geometric network's capabilities and will no longer build additional functionality. Future development and enhancements are focused on the next-generation technologies of the Utility Network and ArcGIS Pro. ESRI utility solution partners are also moving their product lines away from the geometric network, soon supporting only the Utility Network.

Objectives The project creates value for the Company by: (1) mitigating risks associated with product support end of life; (2) enabling detailed asset management and location based analytics to bring clearer understandings around the assets that support energy delivery; (3) increasing productivity through use of shortcuts, templates, and streamlined workflows within the software; (4) providing extensive, out-of-the-box tracing tools; (5) providing 3D visualization functionality; (6) enabling users with editing tools, giving them guidance at every step of the process for developing workflows and enforcing stronger data integrity; (7) viewing the up to date network in a map or schematic diagram and be able to quickly toggle back and forth between them; and (8) enabling archiving and historical versioning to view the state of the electric network over time. All of these capabilities will result in greater insight and efficiency that improves the safety and delivery to customers of Michigan. The Utility Network enables implementation of third-party tools that will allow us to keep the operational model more up to date as circuits with temp conditions and/or control tags can be imported as needed.

Scope The project scope includes: (1) upgrading all database, web, and application servers to supported Windows version; (2) upgrading end user application from ArcGIS Desktop to ArcGIS Pro; (3) migrating and converting LVD and HVD GIS data from geometric network data schema to the Utility Network, iteratively publishing data to new model for consumption; (4) reconfiguring electric applications that are integrated with GIS or that consume GIS data; and (5) creating substation asset model.

Alternatives Alternatives considered include: (1) Continue to use geometric network. This alternative was not selected because the architecture is at the end of its life. Additionally, dependent third-party solutions are moving away from the geometric network, making it unsustainable for continued use. (2) Moving to Utility Network and migrating to a supported platform. This alternative was chosen to enable the Company to leverage a cloud-based solution and provide options for utilizing third-party solutions.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/1/2027	8/1/2027	4/1/2028	9/15/2029
	In-Service/Go-Live	**Closeout**	
	10/15/2029	12/4/2029	

FUNDING SUMMARY

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Cap+COR	$4.108	$9.980	$6.319	-	-	-	-	-	$20.408
O&M	$1.560	$1.497	$1.951	$0.097	$0.097	$0.097	-	-	$5.299
Total Cost of Ownership	$5.668	$11.477	$8.271	$0.097	$0.097	$0.097	-	-	**$25.707**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.541	$1.605	$2.135	-	-	-	-	-	**$4.281**
Outside Services	$2.461	$7.417	$4.585	-	-	-	-	-	**$14.464**
Business Expense/Overheads	$0.506	$2.360	$1.481	-	-	-	-	-	**$4.347**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$2.160	$0.095	$0.070	-	-	-	-	-	**$2.325**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$5.668	$11.477	$8.271	-	-	-	-	-	**$25.416**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.560	$1.497	$1.951	$0.097	$0.097	$0.097	-	-	**$5.299**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.560	$1.497	$1.951	$0.097	$0.097	$0.097	-	-	**$5.299**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$4.108	$9.980	$6.319	-	-	-	-	-	**$20.408**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$4.108	$9.980	$6.319	-	-	-	-	-	**$20.408**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	Medium	High	GIS 10.8.1 will be an unsupported platform in 2028. Keeping the platform version and supporting software versions compatible is becoming more challenging due to all development resources on the vendor side being focused on the Utility Network extension. GIS is also not positioned to support near real time systems
Major Application Failure	Medium	Medium	GIS resides on unsupported platform significantly increasing the likelihood of failure to one or more components.

OTHER VALUE

Type	Description
Risk Mitigation	A utility network has a built-in mechanisms to detect any logically inconsistent associations among features. This is done by system defined business rules and logic that allows the utility to enhance the geospatial system of record with network rules, attribute rules, and contingent values. Allows Consumers Energy to enforce data integrity by applying additional constraints to reduce the number of valid field inputs. Templates, which are a predefined collection of data construction tools, help streamline the adding data workflow. Attribute rules allow Consumers Energy to improve the user experience by restricting the valid entries on a field to a set list or range of values based on real world conditions. This enhanced integrity enables greater confidence in the analytics from the system of insight and reduces the potential for human error.
Risk Mitigation	Asset internals cannot be easily visualized or analyzed. Utility Network will Improve in how assets are visualized, analyzed and aid in equipment inspection and ability to field verify that GIS appropriately reflects the current state of the assets (not buried in tables, CAD files or SAP).
Intangibles	Create a platform to enable a simplified enterprise-wide mobile mapping solution focused on map-based workflows.
Avoided Costs	Current GIS configuration gives no ability to view gas network at different points in time. To achieve this today, GIS Analyst must export the entire database at various times of the year. Utility Network (UN)allows the model to be Design and configure OOTB functionality to query, view and extract data from different points in time.
Risk Mitigation	Deploy enterprise GIS hosted entirely in Microsoft Azure.
Capacity	Design a cloud operating model.
Risk Mitigation	Design and implement replication solution with the goal of simplifying the process and reducing points of failure.
Capacity	Develop a strategy for UN migration and migration to Azure cloud.
Intangibles	Downstream applications use different data models. UN offers a standardized data model which can serve as a foundation. The UN data model benefits from vendor support and upgrades resulting in faster speed to delivery and reduction in custom solutions requiring in-house maintenance.
Intangibles	Enhanced import/export procedures from CAD to reduce the complexity of features in GIS.

Additional 'Other Value' statement(s). Open BPS to view

Energy Assistance Enhancements and Maintenance Annual Upd: Report Pulled: 4/15/2026 Item ID: 6683

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias CARE 5.0, Consumers Affordable Resource for Energy (CARE) Annual Updates, Energy Assistance Enhancements and Maintenance Annual Updates

Description The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy (CARE) project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interfaces and updates to SAP to process various requests. Upcoming modifications will be identified following an ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services (DHHS) and Michigan Public Service Commission (MPSC) to prioritize the list of changes.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement Each grant year, DHHS and MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track active CARE customers, and how they will administer the Michigan Energy Assistance Program (MEAP) benefits through bill credits and arrears forgiveness. The criteria changes significantly each year; therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requirements are not fulfilled, the Company is at risk of losing state Low Income Energy Assistance Fund (LIEAF) funds to assist low-income customers with paying their energy bills, thereby increasing the customers risk of shutoff for non-payment. In addition, our energy assistance programs function within all software platforms in the company which consistently need enhancements and updates.

Objectives The project will provide the following value: (1) complete modifications to internal SAP application and Agency Portal to receive LIEAF funding, which can be used to provide customers the bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LIEAF funding; and (3) complete modifications to customer facing platforms.

Scope The project scope includes: (1) updating the enrollment and status process; (2) allowing for flat monthly bills; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and Michigan Public Service Commission; (6) updating CARE dunning process; and (7) updating the assistance portal (CE PASS) functionality to enhance Agency Self-Service.

Alternatives Alternatives considered include: (1) continue with current process. This alternative was not chosen because it would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization. This alternative was not selected because it would remove ownership and visibility into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. This option was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems such as SAP, a large internal system that supports broad areas of the business, and the Agency Portal, an internally developed web application, therefore a single cloud or third-party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.316	$0.274	$0.293	$0.293	$0.293	$0.293	$0.293	-	$2.055
Total Cost of Ownership	$0.316	$0.274	$0.293	$0.293	$0.293	$0.293	$0.293	-	**$2.055**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.302	$0.282	$0.154	$0.154	$0.154	$0.154	$0.154	-	**$1.354**
Outside Services	-	$(0.026)	$0.125	$0.125	$0.125	$0.125	$0.125	-	**$0.599**
Business Expense/Overheads	$0.014	$0.018	$0.014	$0.014	$0.014	$0.014	$0.014	-	**$0.101**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.316	$0.274	$0.293	$0.293	$0.293	$0.293	$0.293	-	**$2.055**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.316	$0.274	$0.293	$0.293	$0.293	$0.293	$0.293	-	**$2.055**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.316	$0.274	$0.293	$0.293	$0.293	$0.293	$0.293	-	**$2.055**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	As a result of our compliance with CARE requirements, we have access to MEAP funds that help to pay down low-income customer's arrears, therefore preventing those from being written off. This year, we are expecting to enroll 9,350 customers with an average arrears of $285, thus potentially avoiding $2.6M in bad debt write-offs.
Risk Mitigation	As a result of our compliance with CE PASS requirements, Department of Health and Human Service and other agencies would not be able to assist our customers. This could result in $60-$70 million dollars not able to be funded to the company.

Enhancements - Customer Experience and Operations- Cap

Report Pulled: 4/14/2026 **Item ID:** 8776

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Enhancements - Customer Experience and Operations- O&M, Enhancements - Customer Experience and Operations- Cap

Description The Enhancements – Customer Experience – Operations project provides funding for small changes and improvements to existing software to address requests needed due to changing business requirements.

Portfolio IT Services > Applications > Customer Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface requiring smaller effort software application changes. These software enhancements are neither projects nor operational work but require funding for resources. The annual budget cycle should ensure funding is provided for software enhancement small work efforts to ensure we are leveraging the value of existing IT investments to support business processes.

Objectives Requests for this funding are governed by a cross-functional board of representatives from each area which meets monthly to evaluate and prioritize the work. The board assesses requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing software application investments for Customer Experience and Operations.

Scope The enhancement requests are fulfilled to provide functionality for areas such as dunning, customer billing, programs for low income customers (i.e. Winter Protection Program, Special Protection Program), Company website, contact center, energy efficiency, and rates.

Alternatives Historically, specific budget was not allocated for enhancements work requiring efforts to identify funding for each request. As part of our review process the alternative considered was to not provide funding for enhancements. However, this limits our ability to make software changes to support process improvements, regulatory changes, and to meet legally required system changes.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.354	-	-	-	-	-	-	-	$0.354
O&M	$0.069	-	-	-	-	-	-	-	$0.069
Total Cost of Ownership	$0.423	-	-	-	-	-	-	-	**$0.423**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.329	-	-	-	-	-	-	-	**$0.329**
Outside Services	$0.009	-	-	-	-	-	-	-	**$0.009**
Business Expense/Overheads	$0.068	-	-	-	-	-	-	-	**$0.068**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.017	-	-	-	-	-	-	-	**$0.017**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.423	-	-	-	-	-	-	-	**$0.423**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.069	-	-	-	-	-	-	-	**$0.069**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.069	-	-	-	-	-	-	-	**$0.069**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.354	-	-	-	-	-	-	-	**$0.354**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.354	-	-	-	-	-	-	-	**$0.354**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Enhancements-CX&O-O&M

Report Pulled: 4/15/2026 **Item ID: 11375**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Applications Currency and Enhancements - CE&O - O&M, Application Currency and Enhancements - CE&O - O&M, Application Currency - CE&O - O&M, Enhancements - CE&O - O&M, Enhancements-CE&O-O&M, Enhancements-CX&O-O&M

Description The CX&O initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in the CX&O Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for CX&O. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience Operations, Applications Support and, Device Management.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.221	-	-	-	-	-	-	-	$0.221
Total Cost of Ownership	$0.221	-	-	-	-	-	-	-	**$0.221**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.209	-	-	-	-	-	-	-	**$0.209**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.012	-	-	-	-	-	-	-	**$0.012**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.000	-	-	-	-	-	-	-	**$0.000**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.221	-	-	-	-	-	-	-	**$0.221**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.221	-	-	-	-	-	-	-	**$0.221**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.221	-	-	-	-	-	-	-	**$0.221**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-Operations-Capital

Report Pulled: 4/15/2026 **Item ID:** 11325

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Application Currency and Enhancements - Operations - Capital, Enhancements - Operations - Capital, Enhancements-Operations-Capital

Description The Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-OPERATIONS

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in the Operations Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.122	-	-	-	-	-	-	-	$0.122
O&M	-	-	-	-	-	-	-	-	-
Total Cost of Ownership	$0.122	-	-	-	-	-	-	-	**$0.122**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.112	-	-	-	-	-	-	-	**$0.112**
Outside Services	$0.011	-	-	-	-	-	-	-	**$0.011**
Business Expense/Overheads	-	-	-	-	-	-	-	-	-
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.122	-	-	-	-	-	-	-	**$0.122**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.122	-	-	-	-	-	-	-	**$0.122**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.122	-	-	-	-	-	-	-	**$0.122**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-Security-Capital

Report Pulled: 4/14/2026 **Item ID: 11338**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias Cyber Security Enhancements, Application Currency and Enhancements - Security - O&M, Enhancements – Security – O&M, Enhancements – Security – Capital, Enhancements-Security-Capital

Description This initiative will use Capital funding to make enhancements to existing technology and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements in accordance with accounting rules.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MGM

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance.

Alternatives Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.404	$0.816	$0.868	$0.868	$0.868	$0.868	$0.868	-	$5.560
O&M	$0.020	$0.153	$0.083	$0.083	$0.083	$0.083	$0.083	-	$0.587
Total Cost of Ownership	$0.424	$0.969	$0.951	$0.951	$0.951	$0.951	$0.951	-	**$6.147**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.163	$0.245	$0.235	$0.235	$0.235	$0.235	$0.235	-	**$1.584**
Outside Services	-	$0.173	$0.168	$0.168	$0.168	$0.168	$0.168	-	**$1.013**
Business Expense/Overheads	$0.194	$0.525	$0.489	$0.489	$0.489	$0.489	$0.489	-	**$3.164**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.068	$0.026	$0.054	$0.054	$0.054	$0.054	$0.054	-	**$0.366**
Licenses, Permits & Fees	-	-	$0.004	$0.004	$0.004	$0.004	$0.004	-	**$0.020**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.424	$0.969	$0.951	$0.951	$0.951	$0.951	$0.951	-	**$6.147**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.020	$0.153	$0.083	$0.083	$0.083	$0.083	$0.083	-	**$0.587**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.020	$0.153	$0.083	$0.083	$0.083	$0.083	$0.083	-	**$0.587**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.404	$0.816	$0.868	$0.868	$0.868	$0.868	$0.868	-	**$5.560**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.404	$0.816	$0.868	$0.868	$0.868	$0.868	$0.868	-	**$5.560**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-Security-O&M

Report Pulled: 4/14/2026 **Item ID: 8237**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias Cyber Security Enhancements, Application Currency and Enhancements - Security - O&M, Enhancements – Security – O&M, Enhancements-Security-O&M

Description This initiative will use O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MGM

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance.

Alternatives

Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.324	$0.494	$0.506	$0.506	$0.506	$0.506	$0.506	-	$3.347
Total Cost of Ownership	$0.324	$0.494	$0.506	$0.506	$0.506	$0.506	$0.506	-	**$3.347**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.260	$0.373	$0.339	$0.339	$0.339	$0.339	$0.339	-	**$2.326**
Outside Services	-	$0.016	$0.099	$0.099	$0.099	$0.099	$0.099	-	**$0.512**
Business Expense/Overheads	$0.025	$0.085	$0.048	$0.048	$0.048	$0.048	$0.048	-	**$0.349**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.003	$0.019	$0.020	$0.020	$0.020	$0.020	$0.020	-	**$0.124**
Licenses, Permits & Fees	$0.037	-	-	-	-	-	-	-	**$0.037**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.324	$0.494	$0.506	$0.506	$0.506	$0.506	$0.506	-	**$3.347**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.324	$0.494	$0.506	$0.506	$0.506	$0.506	$0.506	-	**$3.347**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.324	$0.494	$0.506	$0.506	$0.506	$0.506	$0.506	-	**$3.347**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enterprise Print - Scan Suite

Report Pulled: 4/14/2026 **Item ID:** 11651

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Enterprise Print - Scan Suite

Description The projects intent is to upgrade the current Enterprise Print and Capture suite for improved data security and integration for the work from home business partner.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** Unspecified

WORK OBJECTIVES

Problem Statement The company currently maintains a print and capture suite that will have support ending in 2025. Only high-level security patches will be available after this date. The company maintains a fleet of servers that are scheduled to be upgraded. The current print and capture suite is not compatible with the targeted server operating systems. The lack of internal resources requires the company to continue to absorb increased costs to contract administrative personal.

Objectives This project maintains cost savings achieved by eliminating wasteful print jobs and further enables a productive, and flexible workforce for business partners working remotely. This project also ensures that the latest data transmission security requirements of are met by the solution.

Scope The project scope includes: (1) upgrading the current suite to the latest version; (2) consolidating the amount of print servers in the environment; (3) training for company personal to administer the suite; (4) converting all workflows from the current system; (5) implementing remediation for security vulnerability risk;. (6) integrating device management with Enterprise Configuration Management Database (CMDB) for asset tracking and monitoring.

Alternatives Alternatives considered: (1) migrating to cloud services. This alternative was not chosen at this time due to maturity levels found with subscription services. (2) other print-scan products. This alternative was not selected as it would required new print and scanning specific to another print-scan product.. (3) Print-scan products that were less costs. This alternative was not selected, due to fewer capabilities offered than the current product, which would introduction inefficiencies in the current processes. (4) upgrade current product. This alternative was chosen due to lower overall cost of not requiring new hardware, maturity of current product, and providing same level of capabilities required to support current processes.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/1/2024	2/6/2024	3/29/2024	5/31/2024
	In-Service/Go-Live	**Closeout**	
	7/31/2024	10/31/2024	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.627	$0.032	-	-	-	-	-	-	$0.659
O&M	$0.085	-	-	-	$0.004	$0.004	-	-	$0.093
Total Cost of Ownership	$0.712	$0.032	-	-	$0.004	$0.004	-	-	**$0.751**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.047	-	-	-	-	-	-	-	**$0.047**
Outside Services	$0.645	-	-	-	-	-	-	-	**$0.645**
Business Expense/Overheads	$0.008	$0.029	-	-	-	-	-	-	**$0.037**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.012	-	-	-	-	-	-	-	**$0.012**
Licenses, Permits & Fees	-	$0.003	-	-	-	-	-	-	**$0.003**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.712	$0.032	-	-	-	-	-	-	**$0.743**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.085	-	-	-	$0.004	$0.004	-	-	**$0.093**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.085	-	-	-	$0.004	$0.004	-	-	**$0.093**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.627	$0.032	-	-	-	-	-	-	**$0.659**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.627	$0.032	-	-	-	-	-	-	**$0.659**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Security maintenance on the current system will become unsupported which will expose the environment to vulnerabilities.
Risk Mitigation	Will allow for mitigation of a current vulnerability with data traffic not encrypted and exposed to any bad agent that would monitor the printer port.

Enterprise Print & Scan Suite Upgrade

Report Pulled: 4/14/2026 **Item ID:** 14039

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Enterprise Print - Scan Suite, Enterprise Print & Scan Suite Upgrade

Description The projects intent is to upgrade the current Enterprise Print and Capture suite for improved data security and integration for the work from home business partner.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS & S

WORK OBJECTIVES

Problem Statement The company currently maintains a print and capture suite that will have support ending in 2028. Only high-level security patches will be available after this date. The company maintains a fleet of servers that are scheduled to be upgraded. The lack of internal resources requires the company to continue to absorb increased costs to contract administrative personal.

Objectives This project maintains cost savings achieved by eliminating wasteful print jobs and further enables a productive, and flexible workforce for business partners working remotely. This project also ensures that the latest data transmission security requirements of are met by the solution.

Scope The project scope includes: (1) upgrading the current suite to the latest version; (3) training for company personal to administer the suite; (4) maintaining all workflows from the current system; (5) continue with remediation for security vulnerability risk;.

Alternatives Alternatives considered: (1) migrating to cloud services. This alternative was not chosen at this time due to maturity levels found with subscription services. (2) other print-scan products. This alternative was not selected as it would required new print and scanning specific to another print-scan product.. (3) Print-scan products that were less costs. This alternative was not selected, due to fewer capabilities offered than the current product, which would introduction inefficiencies in the current processes. (4) upgrade current product. This alternative was chosen due to lower overall cost of not requiring new hardware, maturity of current product, and providing same level of capabilities required to support current processes.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/1/2028	4/1/2028	5/1/2028	7/1/2028
	In-Service/Go-Live	**Closeout**	
	11/1/2028	12/1/2028	

FUNDING SUMMARY

	2028	2029	2030	2031	2032	2033	2034	2035 +	Total
Cap+COR	$0.288	-	-	-	-	-	-	-	$0.288
O&M	$0.063	$0.124	$0.124	$0.124	$0.124	-	-	-	$0.559
Total Cost of Ownership	$0.351	$0.124	$0.124	$0.124	$0.124	-	-	-	**$0.846**

	2028	2029	2030	2031	2032	2033	2034	2035 +	Total
Labor	$0.047	-	-	-	-	-	-	-	**$0.047**
Outside Services	$0.257	-	-	-	-	-	-	-	**$0.257**
Business Expense/Overheads	$0.047	-	-	-	-	-	-	-	**$0.047**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.351	-	-	-	-	-	-	-	**$0.351**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2028	2029	2030	2031	2032	2033	2034	2035 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.063	$0.124	$0.124	$0.124	$0.124	-	-	-	**$0.559**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.063	$0.124	$0.124	$0.124	$0.124	-	-	-	**$0.559**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.288	-	-	-	-	-	-	-	**$0.288**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.288	-	-	-	-	-	-	-	**$0.288**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Security maintenance on the current system will become unsupported which will expose the environment to vulnerabilities.
Risk Mitigation	Will allow for mitigation of a current vulnerability with data traffic not encrypted and exposed to any bad agent that would monitor the printer port.

Enterprise Risk Management

Report Pulled: 4/15/2026 **Item ID:** 10481

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Enterprise Risk Management

Description The project will implement software to streamline Enterprise Risk Management (ERM) processes, improve efficiency, provide risk identification and repository tools, and deliver real-time risk data.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement

The Enterprise Risk Team (ERT) collaborates with Risk Owners (ROs) annually to identify new risks, update existing ones, quantify impacts and likelihoods, document mitigation plans, identify trends, and formulate risk tolerance metrics. This process involves iterative exchanges between ERT and ROs to align on content. This effort culminates in multiple risk maps presented annually to senior management and the Board of Directors (BoD). The manual Enterprise Risk Management (ERM) process is intensive and time-consuming, creating risks of human error that can inaccurately quantify risks, introduce data anomalies, and create version tracking issues. The current process results in inefficient use of time by risk analysts and risk owners, limits the breadth of analysis, and affects the Company's ability to promptly identify, analyze, and communicate risks to senior leaders, potentially causing delays in responding to emerging risks. Due to its lengthy nature, the manual process is conducted only once a year but needs to be performed more frequently for proactive enterprise risk management. Utility industry peers use software to more effectively manage enterprise risk management programs.

Objectives

This project creates value for the Company by: (1) providing real-time risk information to stakeholders including the risk team, risk owners, senior management, and the Board of Directors (BoD); (2) supporting proactive risk management; (3) establishing a centralized repository for risk identification, management, and mitigation plans; (4) reducing waste through simplified processes; and (5) enhancing efficiency for risk owners and analysts.

Scope

The project scope includes: (1) creating risk analysis templates and tools for automated reporting; (2) establishing automated workflows to perform risk updates; (3) configuring dynamic templates that prompt the risk owners based on prior selections; (4) organizing risk assessments through an online and searchable data repository; (5) creating new reports and executive dashboards; (6) migrating data; and (7) setting record retention rules.

Alternatives

Alternatives considered include: (1) Continuing to use the current manual processes. This alternative was not chosen due to inefficiencies, poor quality results, and limited frequency of risk reviews. (2) Building a custom internal enterprise risk solution. This alternative was not selected because it does not incorporate best practices available in risk management software provided by industry leaders. (3) Implementing a software solution from a leading enterprise risk solution vendor. Although this introduces new license and ongoing support costs, it is preferred since it incorporates industry best practices, ensures application reliability, security, stability through vendor support, and provides innovation and insights via risk information reporting through management dashboards. Additionally, it aligns the Company with utility industry peer practices for more effective enterprise risk management.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/1/2027	10/1/2027	12/1/2027	5/1/2028
	In-Service/Go-Live	**Closeout**	
	6/1/2028	7/3/2028	

FUNDING SUMMARY

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Cap+COR	-	$0.184	-	-	-	$0.001	-	-	$0.185
O&M	$0.100	$0.122	$0.115	$0.115	$0.115	$0.017	-	-	$0.584
Total Cost of Ownership	$0.100	$0.306	$0.115	$0.115	$0.115	$0.018	-	-	**$0.769**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.002	$0.069	$0.007	$0.007	$0.007	$0.006	-	-	**$0.097**
Outside Services	$0.004	$0.138	$0.014	$0.014	$0.014	$0.011	-	-	**$0.194**
Business Expense/Overheads	$0.000	$0.005	-	-	-	$0.001	-	-	**$0.006**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.074	$0.074	$0.074	$0.074	$0.074	-	-	-	**$0.372**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.080	$0.286	$0.095	$0.095	$0.095	$0.018	-	-	**$0.670**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.100	$0.122	$0.115	$0.115	$0.115	$0.017	-	-	**$0.584**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.100	$0.122	$0.115	$0.115	$0.115	$0.017	-	-	**$0.584**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.184	-	-	-	$0.001	-	-	**$0.185**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.184	-	-	-	$0.001	-	-	**$0.185**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Implementing a centralized solution will enhance risk management by effectively addressing potential risks. Currently, one-third of the 150 risk tolerance metrics are categorized as red. The number of risks tracked by the Corporate Risk group is expected to increase over time.
Avoided Costs	The ERM Group can save up to 252 hours annually through efficiencies in: (1) Risk form configuration (24 hours saved); (2) Workflow including email/phone conversations, report creation, and quality control (229 hours saved). These efficiencies would allocate more time for activities such as ad hoc analysis, risk updates to management, emerging risk evaluation, and risk mitigation planning. Business areas can save up to 127 hours annually through efficiencies in: (1) Risk template updates (61 hours saved); (2) Emails/phone calls with the Risk Group (33 hours saved); (3) Alignment with the Risk Group and their own management chains (32 hours saved). These efficiencies would allow risk owners to concentrate on business operations and implementing risk reduction mitigation rather than administratively filling out risk forms.

Enterprise Service Bus Application 2024-2025 Upgrade

Report Pulled: 4/15/2026 **Item ID:** 11727

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ESB BW6 Upgrade,Enterprise Service Bus Application Upgrade, Enterprise Service Bus Application 2023-2024 Upgrade, Enterprise Service Bus Application 2024-2025 Upgrade

Description This project will upgrade and migrate the Business Works developer application to the next version.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement

Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway, be more scalable, secure, and capable of integrating to a service-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of approximately $80,000 annually, this is just temporary coverage and serves only to delay the need for an upgrade.

Objectives

The value this project provides the Company includes: (1) cost avoidance to avoid extensive payments for extend support purposes; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies.

Scope

The project scope includes implementing current version of all applications that are part of the ESB application, database version, and required database drivers.

Alternatives

Alternatives considered included: (1) Accept the annual $80,000 extended maintenance cost. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meter management. The current implementation of the ESB platform was built with 5 years of growth in mind. This alternative was not chosen due to risk to Company operations , and the additional expense. (2) Replace the on-premise upgrade plan to implement a cloud-based solution. A cloud migration would also take longer to complete, which would put the Company at risk of falling outside of the current vendor support window for the products current version. (3) Upgrade the existing application. This option was selected because it best meets the Company needs for the near future by restoring vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
9/4/2024	10/7/2024	11/15/2024	1/8/2025
	In-Service/Go-Live	**Closeout**	
	10/18/2025	11/21/2025	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.012	$0.302	-	-	-	-	-	-	$0.314
Total Cost of Ownership	$0.012	$0.302	-	-	-	-	-	-	**$0.314**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.010	$0.293	-	-	-	-	-	-	**$0.303**
Outside Services	$0.002	-	-	-	-	-	-	-	**$0.002**
Business Expense/Overheads	-	$0.008	-	-	-	-	-	-	**$0.008**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.012	$0.302	-	-	-	-	-	-	**$0.314**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.012	$0.302	-	-	-	-	-	-	**$0.314**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.012	$0.302	-	-	-	-	-	-	**$0.314**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Consumers Energy will lose support on critical ESB software components that support OpenWay Collection Engine, SAP, ITRON, DIV, DRMS, MDM, BWP, PayGo, ADMS, Field Service Solution, and Digital Customer Experience. Rebuilding the ESB Platform and ensuring the current production integrations will not be impacted as well as meeting or exceeding current service levels is critical.
Avoided Costs	Consumers Energy will need to purchase an extended support contract with the vendor to maintain support of the older version. Going too long without upgrading puts Consumers at risk of losing any level of support from the vendor. Current estimate is $80,000 of extended support
Capacity	The current implementation of the ESB platform was built with 5 years of growth in mind. Upgrading the ESB on a regularly scheduled cadence will allow Consumers to grow the the application around the business' needs.

Enterprise Service Bus 2026-2027 Upgrade

Report Pulled: 4/15/2026 **Item ID: 14030**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Enterprise Service Bus 2027, Enterprise Service Bus 2026-2027 Upgrade

Description This project will upgrade the current ESB software versions in use at the company. This will also implement a container management system, which deploys, manages, and scales microservices or applications that send or receive data via the service bus, and migrate various services to containers.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway, be more scalable, secure, and capable of integrating to a service-based environment. The lack of a container management solution prohibits the adoption of a more cloud native approach leading to retaining legacy solutions.

Objectives The value this project provides the Company includes: (1) implement a container management solution; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies.

Scope The project scope includes (1) implementing the current version of all applications that are part of the ESB application, database version, and required database drivers and (2) implementing a Kubernetes solution for container management and migrate targeted services that are identified as microservices to containers.

Alternatives Alternatives considered included: (1) Accept the current version levels and continue to pay for extended support costs and accept technical obsolescence risk. (2) Only upgrade the existing applications. (3) Upgrade all of the applications as well as evolve the cloud-based instance to a more cloud native architecture by converting containers and implementing a Kubernetes solution to manage the containers. This option was selected because it best meets the Company needs for the near future by maintaining vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
9/1/2026	9/7/2026	10/12/2026	1/5/2027
	In-Service/Go-Live	**Closeout**	
	10/9/2027	11/15/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$0.059	$1.331	-	-	-	-	-	-	$1.390
O&M	$0.059	$1.012	-	-	-	-	-	-	$1.070
Total Cost of Ownership	$0.118	$2.343	-	-	-	-	-	-	**$2.460**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.110	$1.300	-	-	-	-	-	-	**$1.410**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.008	$0.374	-	-	-	-	-	-	**$0.381**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.669	-	-	-	-	-	-	**$0.669**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.118	$2.343	-	-	-	-	-	-	**$2.460**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.059	$1.012	-	-	-	-	-	-	**$1.070**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.059	$1.012	-	-	-	-	-	-	**$1.070**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.059	$1.331	-	-	-	-	-	-	**$1.390**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.059	$1.331	-	-	-	-	-	-	**$1.390**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Unplanned Outages - Corporate	High	Low	Kubernetes provides resilience via self-healing capabilities to detect and replace failed containers, maintaining high availability and reducing outages

OTHER VALUE

Type	Description
Intangibles	Consistency Across Environments: Ensures applications run consistently across development, testing, and production environments via configuration management
Intangibles	Implementing an Azure Kubernetes system provides autoscaling features

Enterprise Service Bus 2028-2029 Upgrade

Report Pulled: 4/15/2026 **Item ID: 14046**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Enterprise Service Bus 2027, Enterprise Service Bus 2026-2027 Upgrade, Enterprise Service Bus 2028-2029 Upgrade

Description This project will upgrade the current Enterprise Service Bus software versions in use at the Company.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement

Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway, be more scalable, secure, and capable of integrating to a service-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of approximately $80,000 annually, this is just temporary coverage and serves only to delay the need for an upgrade.

Objectives

The value this project provides the Company includes: (1) cost avoidance to avoid extensive payments for extend support purposes; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies.

Scope

The project scope includes implementing current version of all applications that are part of the ESB application, database version, and required database drivers.

Alternatives

Alternatives considered included: (1) Accept the annual $80,000 extended maintenance cost. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meter management. The current implementation of the ESB platform was built with 5 years of growth in mind. This alternative was not chosen due to risk to Company operations , and the additional expense. (2) Replace the on-premise upgrade plan to implement a cloud-based solution. A cloud migration would also take longer to complete, which would put the Company at risk of falling outside of the current vendor support window for the products current version. (3) Upgrade the existing application. This option was selected because it best meets the Company needs for the near future by restoring vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
9/2/2028	10/6/2028	11/6/2028	12/4/2028
	In-Service/Go-Live	**Closeout**	
	8/18/2029	9/14/2029	

FUNDING SUMMARY

	2028	2029	2030	2031	2032	2033	2034	2035 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.034	$0.486	-	-	-	-	-	-	$0.520
Total Cost of Ownership	$0.034	$0.486	-	-	-	-	-	-	**$0.520**

	2028	2029	2030	2031	2032	2033	2034	2035 +	Total
Labor	$0.032	$0.454	-	-	-	-	-	-	**$0.486**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.002	$0.032	-	-	-	-	-	-	**$0.034**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.034	$0.486	-	-	-	-	-	-	**$0.520**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2028	2029	2030	2031	2032	2033	2034	2035 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.034	$0.486	-	-	-	-	-	-	**$0.520**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.034	$0.486	-	-	-	-	-	-	**$0.520**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	Medium	Medium	Periodic upgrades are needed to maintain vendor support without additional cost.

OTHER VALUE

Type	Description
Intangibles	New versions are periodically needed to maintain modernization and keep up with security needs.

Field Contractor Work Management Technology Enablement

Report Pulled: 4/21/2026 **Item ID:** 6740

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias FSS Release 4 - Contractor Enablement

Description The project provides the ability to electronically manage contractor work and increases accuracy and timeliness of information processing for field work deliverables. This project additionally creates new opportunities to measure and optimize field work processes supporting customer on-time delivery goals.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement Contractor field employees use manual, paper-based processes and generic communication technologies (phone, radio, email, collaboration sites) to perform work for the Company. Due to the non-electronic format, inaccuracy, and delay of information processing there are negative impacts to the availability and accuracy of work status. This limits the opportunity to measure and optimize field work processes that support customer on-time delivery and other goals.

Objectives The project will add value by: (1) improving on-time delivery of customer work by providing electronic work order information to contractors; (2) improving customer satisfaction through efficiency in scheduling work and reporting on the progress electronically; (3) increasing safety by tracking work and contractor status providing visibility into the last known location of the contractor; (4) improving material management; (5) making it easier to move emergent work to contractors to balance workloads and meet customer commitments; and (6) enabling real time updates to work order information, increasing data accuracy and reducing invoice reconciliation time.

Scope The project scope includes: (1) identifying requirements for a Bring Your Own Device (BYOD) field contractor work management technology solution and process; (2) developing, configuring, and testing interfaces, hardware, and software for the solution; (3) implementing the solution and process for the following work groups: Electric High-Voltage Distribution (HVD), Electric Low-Voltage Distribution (LVD), Mutual Assistance, Forestry, Gas Distribution, Gas Code Compliance, and Substation Operations Construction/Metro; (4) updating the following vendor contract types to support BYOD field contractor work management: zone, specific bid, ancillary, electric storm, and mutual assistance; and (5) training field contractors on the new technology and processes.

Alternatives The alternatives considered included: (1) Continue with the current paper-based process. This alternative was not selected because this approach does not allow for the timely, data-driven work management metrics required to improve service to customers. (2) Use the current Company mobile application. This alternative was not selected because the solution is not expected to receive long term investments by the vendor and the mobile application would require more upfront investment than the proposed option. (3) Use off-platform options such as ServiceBench. This alternative was not selected because contractors would not be able to leverage the benefits and integrations with the existing platform and it would require additional new integrations. (4) Provide Company-funded field devices to contractors. This alternative was not selected because the investment in hardware, management of on-boarding and off-boarding of devices to contractors, and training and change management is cost-prohibitive and introduces a risk of the loss of control of information security and corporate assets. Leveraging the existing field work management solution was chosen because it uses existing well-developed functionality while leveraging cloud-based, BYOD capabilities to move short-term and long-term contractors from paper processes to the established, standard work management system.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/31/2022	3/31/2022	9/30/2022	7/31/2023
	In-Service/Go-Live	**Closeout**	
	9/16/2024	10/1/2024	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	-	$0.027	$0.343	$1.314	$0.045	-	-	-	$1.730
O&M	$0.243	$0.218	$0.023	$0.352	$0.002	$0.508	$0.508	$0.508	$2.361
Total Cost of Ownership	$0.243	$0.245	$0.367	$1.665	$0.047	$0.508	$0.508	$0.508	**$4.091**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.229	$0.082	$0.098	$1.040	$0.043	-	-	-	**$1.492**
Outside Services	-	$0.144	$0.212	$0.231	$0.000	-	-	-	**$0.587**
Business Expense/Overheads	$0.014	$0.019	$0.054	$0.122	$0.009	-	-	-	**$0.217**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.003	$0.256	$(0.004)	-	-	-	**$0.255**
Licenses, Permits & Fees	-	-	-	$0.017	-	-	-	-	**$0.017**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.243	$0.245	$0.367	$1.665	$0.047	-	-	-	**$2.568**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	$(0.144)	$(0.144)	$(0.144)	$(0.144)	$(0.144)	-	**$(0.719)**
	Initial	$0.243	$0.218	$0.023	$0.352	$0.002	$0.508	$0.508	$0.508	**$2.361**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.243	$0.218	$(0.120)	$0.208	$(0.142)	$0.364	$0.364	$0.508	**$1.642**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.027	$0.343	$1.314	$0.045	-	-	-	**$1.730**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.027	$0.343	$1.314	$0.045	-	-	-	**$1.730**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.840

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	"CE Way" Maturity - The project enables data to be more accessible electronically so that it can be visualized, access to data provides increased visibility to problem solving, and Service Suite forms allow for increased standardization.
Intangibles	Customer On-time Deliver (COTD) - Provides real-time updates for work order progression and completion, and provides increased efficiency in dispatching work to contractors.
Intangibles	Electric Reliability - Improves efficiency in dispatching of emergent work to contractors.
Avoided Costs	Engineering/System Owner Efficiencies: Estimated 1 hour per week @ 50 weeks for 10 system owners = 500 hours annually *$50/hr = $25,000 Annual $ Saved (Max). Annual $ Avoided (Min - 75% of Max) = $18,750 * 29.8% (O&M) = $5,588 annual avoided costs
Avoided Costs	Field Leader & Back End Efficiencies: 1 Hour per week for each long cycle field leaders/back office personnel - "200 people*50weeks= 20K hours * $50/hr = $500K.* Annual $ Avoided (Min - 75% of Max) = $375K. $375K * 29.8% (O&M) = $111,750 annual avoided costs - ELECTRIC SPLIT
Avoided Costs	Field Leader & Back End Efficiencies: 1 Hour per week for each long cycle field leaders/back office personnel - "200 people*50weeks= 20K hours * $50/hr = $500K.* Annual $ Avoided (Min - 75% of Max) = $375K. $375K * 29.8% (O&M) = $111,750 annual avoided costs - GAS SPLIT
Avoided Costs	Increase Back Office Productivity for Contractor Admins: 1 employee for 6 hours a week and 50 weeks per year. Total hours reclaimed annually = 300 hours * $50/hr = $15,000. Annual $ Avoided (Min - 75% of $15,000) = $11,250 * 29.8% (O&M) = $3,353.
Avoided Costs	Increased Productivity for Contractors: 150 hours reclaimed per month * 12 Months a year = 1,800 total hours reclaimed annually * rate of $71.70/hr = $129,060 total. Annual $ Avoided (Min - 75% of $139,060) = $96,795 * 29.8 (O&M)= $28,845

Field Mapping and Graphics

Report Pulled: 4/14/2026 **Item ID: 8771**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias ArcPad Retirement, Field Mapping and Graphics

Description This project will implement a solution for the mobile field mapping and data collection that can search and view facility map data, view work order designs, and create work order as-built construction drawings in the field. This software technology increases process efficiency by consolidating field graphics functionality, reducing IT complexity and testing, and increasing adoption in the field through ease of use. In addition, it allows the Company to move to a supported application platform and retire the unsupported ArcPad solution.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement The current mapping and graphics application was implemented in 2002 and is no longer sold or supported in any capacity, and the customizations developed for the application cannot be changed. Due to the improved accuracy of the CE landbase (streets, political boundaries, etc.), the outdated electric maps that are referencing that data causes the map to be unreadable which causes a safety issue. Additionally, field employees have considerable challenges when attempting to use the software due to slowness, an aged interface, and dated processes.

Objectives The project will add value by: (1) providing more accurate geospatial data, including facility map data, pre-construction designs, and as-built construction drawings; (2) consolidating daily tasks into a more simplified process; (3) eliminating the process waste from duplicating asset data in two systems; (4) enabling the adoption of the Geographic Information System (GIS) standard; and (5) making mapping and graphics data available on field devices.

Scope The project scope includes: (1) installing a new mobile field mapping and graphics application; (2) creating the ability to search and view the facility map data in GIS format along with the ability to search by address; (3) viewing pre-construction work order designs in a new GIS format; and (4) creating as-built construction drawings in GIS format for assigned work orders.

Alternatives Four alternatives were evaluated and three were determined non-viable for the project: (1) Continue maintaining the current ArcPad application. This option was not selected because the Company is no longer able to make changes to the ArcPad application to mitigate issues if the application has critical defects. A total failure of the application could revert field crews back to paper-based facility maps, risking safety using static, outdated data; or require the creation of as-built construction drawings on paper documents. (2) Use the Adobe or Snagit applications for creating as-built construction drawings. This option was not selected because field users would have to use one solution for viewing facility maps and use rudimentary drawing tools like Adobe or Snagit for creating as-built construction drawings. This option was also not selected because it introduces additional costs due to the complexity and customization needed to integrate the applications. (3) Build a custom Mapping and Graphics solution. This option was not selected as existing industry solutions are available at a much lower cost with much less risk. (4) Implementing the new field mapping and graphics software was selected as this option will consolidate field graphics functionality into an efficient process and provide a current, supported solution.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/31/2021	4/30/2021	8/31/2021	6/1/2023
	In-Service/Go-Live	**Closeout**	
	6/30/2023	6/30/2023	

FUNDING SUMMARY

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Cap+COR	-	$0.662	$1.559	$0.875	$0.747	$0.148	-	-	$3.992
O&M	$0.006	$0.016	$0.001	$0.040	$0.016	$0.058	-	-	$0.135
Total Cost of Ownership	$0.006	$0.678	$1.560	$0.915	$0.763	$0.206	-	-	**$4.127**

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Labor	$0.005	$0.221	$0.299	$0.312	$0.229	$0.133	-	-	**$1.199**
Outside Services	-	$0.361	$1.046	$0.372	$0.454	-	-	-	**$2.233**
Business Expense/Overheads	$0.000	$0.096	$0.214	$0.230	$0.080	$0.073	-	-	**$0.693**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	$0.001	$0.001	-	-	-	-	**$0.002**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.006	$0.678	$1.560	$0.915	$0.763	$0.206	-	-	**$4.127**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2020	2021	2022	2023	2024	2025	2026	2027 +	Total
O&M	Reduction	-	-	$(0.064)	$(0.064)	$(0.064)	$(0.064)	$(0.064)	-	**$(0.319)**
	Initial	$0.006	$0.016	$0.001	$0.040	$0.016	$0.058	-	-	**$0.135**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.006	$0.016	$(0.063)	$(0.024)	$(0.048)	$(0.006)	$(0.064)	-	**$(0.183)**
Cap+COR	Reduction	-	-	$(0.149)	$(0.149)	$(0.149)	$(0.149)	$(0.149)	-	**$(0.743)**
	Initial	-	$0.662	$1.559	$0.875	$0.747	$0.148	-	-	**$3.992**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.662	$1.410	$0.727	$0.599	$(0.000)	$(0.149)	-	**$3.249**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.776

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Currently, there is a decrease in morale and increase in stress when redlines aren't processed in a timely way or get held up with technology problems. The current process is go back to the crew to inquire if the redline was completed. When this is a system issue, it causes frustration because then the field has to re-do work in the field. Doing this project will improve morale and improve the relationship between management and the Union by reducing administrative pain, human struggle and disagreements, and wasted time repeating work.
Intangibles	Make OVH (overhead) data available to the field device. The current OVH CAD files have not been maintained in over five years.
Intangibles	Make URD-(Underground Maps) assets readable on field device. This is currently a safety issue.
Intangibles	Reduced errors/defects and postings improves Safety by reducing lag time in data updates and if there's a revisit to the Asset. The correct information is on file.
Risk Mitigation	The application is at risk of failure. It is no longer supported, cannot be upgraded or changed in any manner. Retiring the application and moving to a new application must occur in order for the risk to be removed.

Forward Web Proxy Services

Report Pulled: 4/14/2026 **Item ID:** 13974

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Forward Web Proxy Services

Description This project will replace the Company's existing web proxy service platform with a new, modern, and more resilient platform designed to support both secure internet access and advanced data loss prevention capabilities. A web proxy service acts as a secure intermediary between users and the internet, evaluating, filtering, and forwarding traffic while enforcing company security policies. It acts as an intermediary that evaluates, modifies, and forwards the client's requests to the destination web server. This service offers many benefits for the Company such as advanced filtering. Advanced filtering in a forward web proxy service can filter out unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of attacks such as ransomware.

Portfolio Corporate Services > Security Services > Cyber Security & Shared Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STANDA

WORK OBJECTIVES

Problem Statement The current web proxy platform, implemented in 2021, has caused ongoing operational issues related to web filtering, inconsistent policy enforcement, and intermittent connectivity. These challenges have occasionally limited employee and contractor access to critical internet and cloud-based resources, impacting productivity and increasing security risk. As the Company accelerates its transition to cloud and Software-as-a-Service (SaaS) platforms, maintaining consistent, secure, and reliable internet access is critical. The new platform will provide high availability, improved performance, and enhanced visibility into outbound traffic to ensure that business operations continue seamlessly, even during peak or failover conditions. The platform will also be designed to support flexible deployment models for remote, hybrid, and field-based workers—ensuring that security policies apply consistently regardless of location. In addition to improving reliability, this project introduces data loss prevention (DLP) capabilities as a core function of the web proxy service. These DLP capabilities will help the Company prevent unauthorized transmission of sensitive or regulated information—such as customer data, intellectual property, or operational system details—to unapproved external destinations. Through content inspection, contextual analysis, and integrated policy enforcement, the new solution will identify and block risky behaviors before data leaves the organization. DLP policies will also align with existing information governance frameworks and compliance obligations to provide both proactive protection and auditable oversight of data handling practices

Objectives This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilize technology to enable the Company to handle all types of different workloads from varying geographic locations and is highly available; (3) using a mature and scalable web proxy service provider; (4) providing Zero Trust by continuously verifying every connection request; and (5) implementing data loss prevention capabilities on our core web proxy services.

Scope The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; (3) potentially changing SAAS cloud vendors; (4) and implementing data loss prevention for web proxy services. The Security team did extensive research on alternative web proxy services solutions.

Alternatives Alternatives considered include: (1) continue to use and maintain the current web proxy services platform as it currently is implemented. This alternative was not chosen due to the previous operational issues with the platform that make it unreliable. The result of an unreliable system means that employees and contractors are unable to access business critical services such as email, Teams, ServiceNow, SharePoint Online.; (2) Route all internet traffic through the Company's corporate data center. This alternative wasn't chosen because the capabilities of firewalls aren't as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) Perform an evaluation between existing product with expanded feature sets, such as data loss prevention and alternative vendors that could replace current system with modern vendor platform for web proxy services. This option was chosen because it offers additional analysis with the potential to enhance existing, in place, products with features such as enhanced data loss prevention mechanisms, browser isolation (the ability to contain web pages so that the web page can't affect the client workstation) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's company strategy.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/15/2027	2/15/2027	4/15/2027	6/1/2027
	In-Service/Go-Live	**Closeout**	
	11/15/2027	1/30/2028	

FUNDING SUMMARY

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Cap+COR	$4.478	-	-	-	-	-	-	-	$4.478
O&M	$0.484	$0.139	$0.130	$0.130	$0.130	-	-	-	$1.013
Total Cost of Ownership	$4.962	$0.139	$0.130	$0.130	$0.130	-	-	-	**$5.491**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.059	$0.139	$0.130	$0.130	$0.130	-	-	-	**$0.587**
Outside Services	$0.192	-	-	-	-	-	-	-	**$0.192**
Business Expense/Overheads	$0.503	$0.001	-	-	-	-	-	-	**$0.504**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$4.208	-	-	-	-	-	-	-	**$4.208**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$4.962	$0.139	$0.130	$0.130	$0.130	-	-	-	**$5.491**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.484	$0.139	$0.130	$0.130	$0.130	-	-	-	**$1.013**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.484	$0.139	$0.130	$0.130	$0.130	-	-	-	**$1.013**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$4.478	-	-	-	-	-	-	-	**$4.478**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$4.478	-	-	-	-	-	-	-	**$4.478**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Information Theft	High	High	Avoid the cost and disruption of data loss from users, SaaS apps, and public cloud infrastructure due to accidental exposure, theft, or double extortion ransomware.
Information Theft	High	High	Stop advanced cyberthreats with built-in protections against botnets, command-and-control traffic, risky peer-to-peer sharing, malicious active content, cross-site scripting, fraud sites
Information Theft	High	High	The ability to know when patient zero phishing attacks are attempting to infiltrate the Company with advanced AI-based inline detection
Information Theft	High	High	The application will give the ability to know when patient zero phishing attacks are attempting to infiltrate the Company with advanced AI-based inline detection
Information Theft	High	High	The new solution will have the ability to filter risky and malicious domains and stop the use of DNS tunneling to transfer of malicious payloads and sensitive data

OTHER VALUE

Type	Description
Technology Capability	Browser isolation (the ability to contain web pages so that the web page can't effect the client workstation)
Technology Capability	Empower employees and contractors to securely access web applications and cloud services from anywhere, on any device—and ensure a great digital experience where applicable in the Company.
Technology Capability	Increase service reliability for employees and contractors to internet and cloud-based resources for employees and contractors
Technology Capability	Provide Zero Trust by continuously verifying every connection request
Technology Capability	Sandboxing (a way to safely execute malicious applications without impacting the Company's network)
Technology Capability	The new solution will provide more reliable protection against unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of being attacked by ransomware.

Generation Operations Digital Work Management

Report Pulled: 4/14/2026 **Item ID:** 6766

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias ER Mobility, Generation Operations Work Management Mobility, Generation Operations Digital Work Management, Generation Operations And Compression Digital Work Management, Generation Operations Digital Work Management

Description The project provides mobile software and digital forms for Renewable Generation.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The current work management process for Electric Generation at Renewable Generation sites is cumbersome and largely paper based. Information is currently buried in SAP, may not be complete and is not easily searchable. This system leads to process waste, re-work, and human error. An electronic mobile software will better capture maintenance, condition of equipment, provide visibility to data and records including regulatory tracking while working on equipment, and create a digital punch list for future work.

Objectives This project provides value to the Company through: (1) Productivity is improved and human struggle reduced by simplification of work tracking through the mobile software. Time sheet charging is incorporated to the work order when someone on the crew pushes the clock to start versus being separately entered through SAP Employee Self Service. If there is more than one person on a crew, information is entered for the full crew versus individually, including time tracking. Functionality is available to more easily create a digital punchlist in the field when a worker sees something instead of later writing it on a punchboard and entering it separately into SAP. (2) Employee Engagement improves as the more tech savvy candidate pool for these positions are looking for mobile software to help them do their jobs. (3) Quality is improved by creating a digital punchlist when the technicians find an issue versus manually documenting it later. Accuracy increases and rework decreases when updates are performed right at the time and place of the work instead of afterwards. Productivity can also be tracked and measured for further improvements. This level of tracking is not possible with

Scope The scope of the project includes: the initial roll out for Renewable Generation, which would include: (1) purchase of additional mobile work management software licenses, (2) development and configuration of forms and workflow for these groups (3) and implementing additional reporting capabilities and dashboards.

Alternatives Alternatives considered include: (1) Utilize an SAP work management mobile solution. An SAP work management solution is not preferred since it is a new solution and requires additional project and support cost. (2) Continue the manual paper-based process. Continuing the manual paper-based process was not chosen because of process waste, re-work, and human error. (3) Customize the existing electronic Shift Operations Management System (eSOMS) mobile application to add work management functions. A custom eSOMS mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the eSOMS product was not intended to support. (4) Utilize an out of the box solution to minimize cost and risk to the Company and its employees. The combined Service Suite and digital form solution is the preferred option because it is a proven solution and provides the mobility and digital benefits at a lower cost than other alternatives

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/23/2024	7/23/2024	7/30/2024	10/23/2025
	In-Service/Go-Live	**Closeout**	
	10/23/2025	11/20/2025	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.073	$0.308	-	-	-	-	-	-	$0.382
O&M	$0.004	$0.021	$0.004	$0.072	$0.163	$0.163	-	-	$0.428
Total Cost of Ownership	$0.078	$0.329	$0.004	$0.072	$0.163	$0.163	-	-	**$0.810**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.039	$0.282	-	-	-	-	-	-	**$0.321**
Outside Services	$0.029	-	-	-	-	-	-	-	**$0.029**
Business Expense/Overheads	$0.000	$0.047	-	-	-	-	-	-	**$0.047**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.009	$0.001	-	-	-	-	-	-	**$0.010**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.078	$0.329	-	-	-	-	-	-	**$0.407**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.004	$0.021	$0.004	$0.072	$0.163	$0.163	-	-	**$0.428**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.004	$0.021	$0.004	$0.072	$0.163	$0.163	-	-	**$0.428**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.073	$0.308	-	-	-	-	-	-	**$0.382**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.073	$0.308	-	-	-	-	-	-	**$0.382**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Employee Engagement improves as the more tech savvy candidate pool for these positions are looking for mobile software to help them do their jobs.
Avoided Costs	For Renewable Generation, the improved maintenance program will reduce equipment downtime resulting in an increase to Megawatt hours produced.
Avoided Costs	Functionality is available to more easily create a digital punch list in the field when a worker sees something instead of later writing it on a punchboard and entering it separately into SAP. 2,346 annual notifications (non-maintenance) x 5 minutes saved per notification = 11,730 mins or 195.5 hours per year. 195.5 hours x $56 per hour = $10,948 O&M avoided per year.
Intangibles	Quality is improved by creating a digital punchlist when the technicians find an issue versus manually documenting it later. Accuracy increases and rework decreases when updates are performed right at the time and place of the work instead of afterwards. Productivity can also be tracked and measured for further improvements. This level of tracking is not possible with the current process and information.
Intangibles	Safety is improved as employees have remote access to manuals to reference before moving forward with and during their work. The access to manuals increases productivity and better supports error reduction training by having the manuals available so a worker can move beyond "I think" and "I believe". The project will mitigate the risk of work and safety errors from using outdated procedures.

Genesys Cloud Migration

Report Pulled: 4/14/2026 **Item ID:** 13423

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Genesys Cloud Migration

Description The project will migrate the Company's existing on-premise customer contact solution and deploy it to the Genesys Platform As A Service ("PAAS") cloud-based solution. It will provide the Company with the ability to reduce operational costs for performing upgrades and maintenance, take advantage of new enhancements offered by the vendor, and ensure continued support of a critical customer communication channel.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement In 2028, standard vendor support ends for the current on-premise software and extended support is not available from the vendor. Without vendor support, the application no longer receives security patches, bug fixes, or functionality support from the vendor, which creates security, stability, and reliability risk. With the upcoming end of standard support, the vendor is no longer offering feature enhancements to the current on-premise solution limiting the Company's ability to invest in new ways to better serve its customers.

Objectives This project will provide value to both the Company and its customers through: (1) reducing costs with cloud allocated hardware scalable to current usage needs; (2) reducing operating costs with vendor managed feature updates and maintenance provided without service disruption; (3) providing access to new and innovative capabilities to enhance customer service; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.

Scope The project scope includes: (1) deploying the new PAAS cloud-based solution in the vendor cloud environment; (2) installing a new internet circuit to directly connect the Company's systems to the vendors cloud environment; (3) updating existing customer interactive voice response ("IVR") system to accommodate the new cloud implementation; (4) implement new features supporting analytics, quality, and reporting; and (5) implement a built-in customer survey tool.

Alternatives Alternatives considered include: (1) Defer to later years. This alternative was not selected due to requiring upgrades of existing on-premise hardware, impeding our ability to take advantage of new features offered by the cloud solution, and reducing cost savings opportunities presented by moving to the cloud. (2) Deploy Genesys on-premise solution to new on-premise hardware. This alternative was not selected due cost associated with purchasing new hardware and does not address the security, stability, and reliability risk resulting from the vendor end of support for the on-premise software. (3) Select and migrate to a new vendor software. This alternative was not selected due to the complexity of our existing internal integrations between the Genesys platform and the Company's other internal systems. As a result, selecting a new system with a new vendor would make the switch cost prohibitive. (4) Migrate to the Genesys Cloud platform. This alternative was selected due to it building on the Company strategy of moving to cloud, reducing operating and maintenance costs, and reduces risk by ensuring consistent, seamless vendor support.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/1/2024	6/1/2024	8/1/2024	2/10/2025
	In-Service/Go-Live	**Closeout**	
	9/11/2025	9/26/2025	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.148	$0.039	$1.095	$1.132	$0.972	$0.031	-	-	$3.417
Total Cost of Ownership	$0.148	$0.039	$1.095	$1.132	$0.972	$0.031	-	-	**$3.417**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.001	$0.032	$0.004	$0.004	$0.002	-	-	-	**$0.043**
Outside Services	$0.147	$0.006	$0.301	$0.301	$0.150	-	-	-	**$0.905**
Business Expense/Overheads	-	$0.001	$0.015	$0.015	$0.007	-	-	-	**$0.039**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	$0.744	$0.781	$0.781	-	-	-	**$2.305**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.148	$0.039	$1.063	$1.101	$0.941	-	-	-	**$3.292**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	$(0.597)	$(0.378)	$(0.303)	$(0.303)	$(0.153)	-	-	**$(1.736)**
	Initial	$0.148	$0.039	$1.095	$1.132	$0.972	$0.031	-	-	**$3.417**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.148	$(0.558)	$0.716	$0.828	$0.669	$(0.122)	-	-	**$1.681**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.481

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Avoided costs of $1,000,000 associated with on-premise server upgrades which would require both internal and external labor to complete. Savings based on on-prem server upgrades estimated at a total of $970,000 and $30,000 in extended server support would not be needed for the year 2026.
Avoided Costs	Avoided costs of $2,669,170 associated with the Genesys indication of a 20% increase in on-premise software maintenance year over year until the on-premise end-of-life. Calculated by taking the difference between the IT forecasted on-premises software maintenance minus the estimated expected cost with 20% increase for each year starting in 2025. [2025: $1,717,174 (expected) - $1,623,397 (forecast) = $93,777] [2026: $2,060,608 (expected) - $1,638,077 (forecast) = $422,531] [2027: $2,472,730 (expected) - $1,638,077 (forecast) = $834,653] [2028: $2,967,286 (expected) - $1,638,077 (forecast) = $1,329,209] [Total Savings: $93,777 + $422,531 + $834,653 + $1,329,209 = $2,669,170]
Avoided Costs	Avoided costs of $365,000 associated with reduction of voice circuits. Savings based on $60,000 per year in SIP circuit costs + $60,000 per year in H&H voice circuit costs, minus $63,000 in annual costs for AWS direct connect. Assumes only partial year costs for AWS circuit in 2024. [2024: $120,000 - $40,000 = $80,000] [2025: $120,000 - $63,000 = $57,000] [2026: $120,000 - $63,000 = $57,000] [2027: $120,000 - $63,000 = $57,000] [2028: $120,000 - $63,000 = $57,000] [2029: $120,000 - $63,000 = $57,000] [Total Savings = $80,000 + $57,000 + $57,000 + $57,000 + $57,000 + $57,000 = $365,000]
Avoided Costs	Reduces annual ongoing costs associated with running on-premise solution including virtual machines and storage. Approximate avoided cost of $728,092 per year which was estimated by including the monthly HCL management expense per virtual machine, Azure 3rd copy backup storage, VMware licenses, on-premise Commvault backup storage, operating system licenses, and other shared infrastructure costs.

HR Support Pack and Business Software Inc Upgrade 2025

Report Pulled: 4/15/2026 **Item ID:** 12508

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias , HR Support Pack and Business Software Inc Upgrade 2025

Description The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.

Objectives This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.

Scope The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.

Alternatives Alternatives considered include: (1) Not upgrading to the current support packs which results in noncompliance with financial rules and regulations and inaccurate payroll; (2) there is no economical cloud solution, so this option was not entertained; (3) apply the appropriate support pack upgrades. Option (3) is the preferred option because it enables the company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/5/2025	2/26/2025	3/31/2025	11/1/2025
	In-Service/Go-Live	**Closeout**	
	12/19/2025	12/31/2025	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.257	-	-	-	-	-	-	-	$0.257
Total Cost of Ownership	$0.257	-	-	-	-	-	-	-	**$0.257**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.251	-	-	-	-	-	-	-	**$0.251**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.006	-	-	-	-	-	-	-	**$0.006**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.257	-	-	-	-	-	-	-	**$0.257**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.257	-	-	-	-	-	-	-	**$0.257**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.257	-	-	-	-	-	-	-	**$0.257**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Compliance & Ethics	High	High	Without the release of the new support packs from SAP, Consumers Energy would not be compliant with new HR and tax changes. As a result, it would not be able to calculate and distribute payroll.

OTHER VALUE

Type	Description
Risk Mitigation	The support packs are released throughout the course of the year to ensure compliance with HR and tax changes.

HR Support Pack and Business Software Inc Upgrade 2026

Report Pulled: 4/15/2026 **Item ID:** 12755

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias , HR Support Pack and Business Software Inc Upgrade 2025, HR Support Pack and Business Software Inc Upgrade 2026

Description The Human Resources (HR) Support Pack and Business Software Inc (BSI) upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.

Objectives This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.

Scope The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.

Alternatives oAlternatives considered include: (1) not upgrading to the current support packs, which results in noncompliance with financial rules and regulations and inaccurate payroll. (2) there is no economical cloud solution, so this option was not entertained. (3) the Company decided the best alternative is to apply the appropriate support pack upgrades. This option is preferred because it enables the Company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/5/2026	2/26/2026	3/31/2026	11/1/2026
	In-Service/Go-Live	**Closeout**	
	12/19/2026	12/31/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	-	$0.665	-	-	-	-	-	-	$0.665
Total Cost of Ownership	-	$0.665	-	-	-	-	-	-	**$0.665**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.058	-	-	-	-	-	-	**$0.058**
Outside Services	-	$0.564	-	-	-	-	-	-	**$0.564**
Business Expense/Overheads	-	$0.044	-	-	-	-	-	-	**$0.044**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.665	-	-	-	-	-	-	**$0.665**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.665	-	-	-	-	-	-	**$0.665**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.665	-	-	-	-	-	-	**$0.665**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Compliance & Ethics	High	High	Without the release of the new support packs from SAP, Consumers Energy would not be compliant with new HR and tax changes. As a result, it would not be able to calculate and distribute payroll.

OTHER VALUE

Type	Description
Risk Mitigation	The support packs are released throughout the course of the year to ensure compliance with HR and tax changes.

HR Support Pack and Business Software Inc Upgrade 2027

Report Pulled: 4/15/2026 **Item ID:** 12756

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias , HR Support Pack and Business Software Inc Upgrade 2025, HR Support Pack and Business Software Inc Upgrade 2026, HR Support Pack and Business Software Inc Upgrade 2027

Description The Human Resources (HR) Support Pack and Business Software Inc (BSI) upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.

Objectives This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.

Scope The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.

Alternatives oAlternatives considered include: (1) not upgrading to the current support packs, which results in noncompliance with financial rules and regulations and inaccurate payroll. (2) there is no economical cloud solution, so this option was not entertained. (3) the Company decided the best alternative is to apply the appropriate support pack upgrades. This option is preferred because it enables the Company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/6/2027	2/27/2027	4/2/2027	11/1/2027
	In-Service/Go-Live	**Closeout**	
	12/22/2027	12/29/2027	

FUNDING SUMMARY

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.665	-	-	-	-	-	-	-	$0.665
Total Cost of Ownership	$0.665	-	-	-	-	-	-	-	**$0.665**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.058	-	-	-	-	-	-	-	**$0.058**
Outside Services	$0.564	-	-	-	-	-	-	-	**$0.564**
Business Expense/Overheads	$0.044	-	-	-	-	-	-	-	**$0.044**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.665	-	-	-	-	-	-	-	**$0.665**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.665	-	-	-	-	-	-	-	**$0.665**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.665	-	-	-	-	-	-	-	**$0.665**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Compliance & Ethics	High	High	Without the release of the new support packs from SAP, Consumers Energy would not be compliant with new HR and tax changes. As a result, it would not be able to calculate and distribute payroll.

OTHER VALUE

Type	Description
Risk Mitigation	The support packs are released throughout the course of the year to ensure compliance with HR and tax changes.

HR Support Pack and Business Software Inc Upgrade 2028

Report Pulled: 4/15/2026 **Item ID:** 13420

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias , HR Support Pack and Business Software Inc Upgrade 2025, HR Support Pack and Business Software Inc Upgrade 2026, HR Support Pack and Business Software Inc Upgrade 2027, HR Support Pack and Business Software Inc Upgrade 2028

Description The Human Resources (HR) Support Pack and Business Software Inc (BSI) upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.

Objectives This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.

Scope The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.

Alternatives oAlternatives considered include: (1) not upgrading to the current support packs, which results in noncompliance with financial rules and regulations and inaccurate payroll. (2) there is no economical cloud solution, so this option was not entertained. (3) the Company decided the best alternative is to apply the appropriate support pack upgrades. This option is preferred because it enables the Company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/6/2028	2/27/2028	4/3/2028	11/1/2028
	In-Service/Go-Live	**Closeout**	
	12/22/2028	12/29/2028	

FUNDING SUMMARY

	2028	2029	2030	2031	2032	2033	2034	2035 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.676	-	-	-	-	-	-	-	$0.676
Total Cost of Ownership	$0.676	-	-	-	-	-	-	-	**$0.676**

	2028	2029	2030	2031	2032	2033	2034	2035 +	Total
Labor	$0.059	-	-	-	-	-	-	-	**$0.059**
Outside Services	$0.573	-	-	-	-	-	-	-	**$0.573**
Business Expense/Overheads	$0.044	-	-	-	-	-	-	-	**$0.044**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.676	-	-	-	-	-	-	-	**$0.676**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2028	2029	2030	2031	2032	2033	2034	2035 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.676	-	-	-	-	-	-	-	**$0.676**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.676	-	-	-	-	-	-	-	**$0.676**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Compliance & Ethics	High	High	Without the release of the new support packs from SAP, Consumers Energy would not be compliant with new HR and tax changes. As a result, it would not be able to calculate and distribute payroll.

OTHER VALUE

Type	Description
Risk Mitigation	The support packs are released throughout the course of the year to ensure compliance with HR and tax changes.

HVD Supervisory Control and Data Acquisition (SCADA) Upgr; Report Pulled: 4/15/2026 Item ID: 13968

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , HVD SCADA Upgrade, HVD Supervisory Control and Data Acquisition (SCADA) Upgrade, HVD Supervisory Control and Data Acquisition (SCADA) Upgrade 2025-2026

Description The Electric HVD Monitoring System Upgrade project upgrades the software (every 2 years) and hardware components (every 4 years) of HVD SCADA system. This will include the upgrade of the underlying operating systems and database platforms that the software resides on as needed to maintain vendor support. This system is used to monitor and control generation and high voltage distribution voltage circuits. This project will add additional features and enhancements to HVD Monarch, the Company's HVD SCADA platform that improves efficiency and reliability.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement Running on an older version of the HVD Software could have potential impacts on the reliability and resiliency of the low voltage distribution (LVD) system as well as the HVD system, as distribution reliability metrics depend upon HVD system availability. Maintaining an older version of the software and hardware creates risks associated with vendor responsiveness in addressing problems, as they arise. It will also take more effort to support any upgrades in the future because of difficulties resulting from longer durations between upgrade efforts. If upgrades are delayed, additional full-time resources will be required for the year upgrades occur to address upgrade complexities.

Objectives Upgrading the HVD SCADA software and hardware adds value to the Company by ensuring that problems are promptly addressed when they occur. Additionally, the upgrade includes enhancements and fixes to the core product that support the resiliency of electric delivery, ensuring that customers are receiving the energy they need when they need it. Also, the distribution system depends on availability of the HVD system, staying current with the solution provider upgrades is critical to the resiliency of both systems.

Scope The scope of this project is an upgrade to the HVD SCADA software and hardware, which encompasses the following: (1) upgrading the application software; (2) upgrading the underlying operating systems and database platforms; (3) upgrading the underlying application hardware; (4) implementing new functionality for improved value to the Company; (5) making necessary configuration changes; and (5) updating documentation related to the integration changes.

Alternatives Alternative considered include: (1) Defer the biennial upgrade of the SCADA application and its hardware. The Company targets SCADA biennial application upgrades to stay within two versions of the current application state to maintain application stability and cyber security, given the critical nature of the SCADA system. This alternative was not chosen due to increased security risk and need for vendor support of the application. Additionally, the hardware is already past the end of its useful life and has been moved over to a 3rd party warranty provider. (2) Alternative Vendor solution. This option was not chosen because the move from our current vendor would be time consuming and costly. It could also introduce instability as any alternative solutions have not been proven operationally. (3) Do nothing. This option was not chosen due to the critical nature of these systems and the potential operational risks associated with operating on an unsupported solution. (4) Move to cloud. This option was not chosen as CE's internal security requirement is to host control systems on premise. (5) The option chosen is to complete the upgrade project with associated hardware and software necessary to complete the project that will deliver new functionality for improved value.

DATES (phase end)

Initiation 10/1/2025	**Project Plan & Scope Definition** 2/6/2026	**Final Engineering, Planning & Design** 3/6/2026	**Execution** 10/27/2026
	In-Service/Go-Live 10/27/2026	**Closeout** 12/4/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$0.768	$2.593	-	-	-	-	-	$3.361
O&M	-	$0.080	$0.167	$0.080	$0.080	$0.080	$0.080	-	$0.569
Total Cost of Ownership	-	$0.849	$2.759	$0.080	$0.080	$0.080	$0.080	-	**$3.930**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.012	$0.322	-	-	-	-	-	**$0.334**
Outside Services	-	-	$0.752	-	-	-	-	-	**$0.752**
Business Expense/Overheads	-	$0.080	$0.930	$0.080	$0.080	$0.080	$0.080	-	**$1.332**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.756	$0.756	-	-	-	-	-	**$1.513**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.849	$2.759	$0.080	$0.080	$0.080	$0.080	-	**$3.930**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.080	$0.167	$0.080	$0.080	$0.080	$0.080	-	**$0.569**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.080	$0.167	$0.080	$0.080	$0.080	$0.080	-	**$0.569**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.768	$2.593	-	-	-	-	-	**$3.361**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.768	$2.593	-	-	-	-	-	**$3.361**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Material Weakness in IT General Computer Co	High	Medium	Maintaining the SCADA software will minimize the risks associated with unreliable monitoring.

OTHER VALUE

Type	Description
Avoided Costs	Avoid 1 FTE from IT/OT TEOS that will be required if the upgrade is delayed. This a 1 year FTE only.

HVD Supervisory Control and Data Acquisition (SCADA) Upgra

Report Pulled: 4/15/2026 **Item ID:** 14041

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , HVD SCADA Upgrade, HVD Supervisory Control and Data Acquisition (SCADA) Upgrade, HVD Supervisory Control and Data Acquisition (SCADA) Upgrade 2025-2026, HVD Supervisory Control and Data Acquisition (SCADA) Upgrade 2028-2029

Description The Electric HVD Monitoring System Upgrade project upgrades the software (every 2 years) and hardware components (every 4 years) of HVD SCADA system. This will include the upgrade of the underlying operating systems and database platforms that the software resides on as needed to maintain vendor support. This system is used to monitor and control generation and high voltage distribution voltage circuits. This project will add additional features and enhancements to HVD Monarch, the Company's HVD SCADA platform that improves efficiency and reliability.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement Running on an older version of the HVD Software could have potential impacts on the reliability and resiliency of the low voltage distribution (LVD) system as well as the HVD system, as distribution reliability metrics depend upon HVD system availability. Maintaining an older version of the software and hardware creates risks associated with vendor responsiveness in addressing problems, as they arise. It will also take more effort to support any upgrades in the future because of difficulties resulting from longer durations between upgrade efforts. If upgrades are delayed, additional full-time resources will be required for the year upgrades occur to address upgrade complexities.

Objectives Upgrading the HVD SCADA software and hardware adds value to the Company by ensuring that problems are promptly addressed when they occur. Additionally, the upgrade includes enhancements and fixes to the core product that support the resiliency of electric delivery, ensuring that customers are receiving the energy they need when they need it. Also, the distribution system depends on availability of the HVD system, staying current with the solution provider upgrades is critical to the resiliency of both systems.

Scope The scope of this project is an upgrade to the HVD SCADA software and hardware, which encompasses the following: (1) upgrading the application software; (2) upgrading the underlying operating systems and database platforms; (3) upgrading the underlying application hardware; (4) implementing new functionality for improved value to the Company; (5) making necessary configuration changes; and (5) updating documentation related to the integration changes.

Alternatives Alternative considered include: (1) Defer the biennial upgrade of the SCADA application and its hardware. The Company targets SCADA biennial application upgrades to stay within two versions of the current application state to maintain application stability and cyber security, given the critical nature of the SCADA system. This alternative was not chosen due to increased security risk and need for vendor support of the application. Additionally, the hardware is already past the end of its useful life and has been moved over to a 3rd party warranty provider. (2) Alternative Vendor solution. This option was not chosen because the move from our current vendor would be time consuming and costly. It could also introduce instability as any alternative solutions have not been proven operationally. (3) Do nothing. This option was not chosen due to the critical nature of these systems and the potential operational risks associated with operating on an unsupported solution. (4) Move to cloud. This option was not chosen as CE's internal security requirement is to host control systems on premise. (5) The option chosen is to complete the upgrade project with associated hardware and software necessary to complete the project that will deliver new functionality for improved value.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/1/2028	2/6/2028	3/6/2028	10/27/2029
	In-Service/Go-Live	**Closeout**	
	10/27/2029	12/4/2029	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	$1.781	$1.619	-	-	$3.400
O&M	-	-	-	-	$0.171	$0.167	$0.080	-	$0.418
Total Cost of Ownership	-	-	-	-	$1.951	$1.786	$0.080	-	**$3.818**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	-	-	-	$0.200	$0.322	-	-	**$0.522**
Outside Services	-	-	-	-	$0.300	$0.400	-	-	**$0.700**
Business Expense/Overheads	-	-	-	-	$0.691	$0.305	$0.080	-	**$1.077**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	$0.760	$0.760	-	-	**$1.520**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	-	-	-	$1.951	$1.786	$0.080	-	**$3.818**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	$0.171	$0.167	$0.080	-	**$0.418**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	$0.171	$0.167	$0.080	-	**$0.418**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	$1.781	$1.619	-	-	**$3.400**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	$1.781	$1.619	-	-	**$3.400**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Material Weakness in IT General Computer Cc	High	Medium	Maintaining the SCADA software will minimize the risks associated with unreliable monitoring.

OTHER VALUE

Type	Description
Avoided Costs	Avoid 1 FTE from IT/OT TEOS that will be required if the upgrade is delayed. This a 1 year FTE only.

Integrated Energy Management Platform Optimization

Report Pulled: 4/14/2026 **Item ID:** 14021

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Strategic Shift for PCI Energy Solutions, Strategic Shift for Energy Trading Platform, Strategic Shift for Energy Buying and Selling Platform, Integrated Energy Management Platform Optimization

Description This project will reduce data center assets running PCI Energy Solutions by migrating into vendor cloud hosting solution. This will optimize vendor support, reduce operational costs (upgrades, server maintenance) and allow the Company to leverage new cloud capabilities.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement PCI Energy Solutions (PCI) provides software the Company uses to fulfill the Federal Energy Regulatory Commission (FERC) requirement of communicating unit availability to the Regional Transmission Operator and become more efficient at buying and selling electricity in the wholesale market. Due to the solution being Company hosted, the Company is not able to leverage benefits of the functionality in the vendor's cloud hosting solution (Software as a Service (SaaS)). The complex nature of the solution requires various IT and business support teams to monitor, maintain and upgrade the system. Due to the critical nature of the application, the Company is looking to the SaaS hosting to benefit from the uptime SLA of 99.95% and the streamlined operational support for faster issue resolution.

Objectives This project creates value for the Company by: (1) utilizing the vendor's SaaS environment which provides efficiencies for timely operational support. Currently, as an example, IT sends PCI a database copy so they can replicate the Company's environment in the vendor's system. This leads to waste of resources, time and increased support costs. (2) Freeing up resources for more value add work. As the Company optimized the organization, it is very important to reduce waste and work on the most valuable items; (3) reducing Oracle footprint; (4) reducing IT labor support costs; (5) reducing ongoing networking equipment replacement and upgrade costs.

Scope The project scope includes: (1) planning and executing the data migration; (2) designing and configuring new and existing vendor SaaS components; (3) implementing integrations to COTS (Commercial Off-The-Shelf) and custom systems; (4) testing; (5) educating and increasing the skills of the employees to leverage the new vendor SaaS services; (6) decommissioning old infrastructure.

Alternatives Alternatives considered include: (1) continue to use the Company hosted installation of PCI. This alternative was not chosen due to the significant waste involved in maintaining the system, the inability to leverage Cloud functionality, and the failure to decrease the reliance on Oracle servers. (2) Move to a different energy market platform. This alternative was not selected because the different platform would have lesser options and would not be able to utilize PCIs bid to build process. (3) Move to the vendor SaaS. This alternative was selected as the Company will utilize the latest technology and optimize operational support.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
5/2/2027	6/3/2027	8/11/2027	2/10/2028
	In-Service/Go-Live	**Closeout**	
	3/9/2028	3/16/2028	

FUNDING SUMMARY

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Cap+COR	$4.194	$0.135	-	-	-	-	-	-	$4.330
O&M	$2.299	$0.051	-	-	-	-	-	-	$2.350
Total Cost of Ownership	$6.493	$0.186	-	-	-	-	-	-	**$6.680**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.580	$0.136	-	-	-	-	-	-	**$0.716**
Outside Services	$1.348	-	-	-	-	-	-	-	**$1.348**
Business Expense/Overheads	$0.520	$0.050	-	-	-	-	-	-	**$0.570**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$3.358	-	-	-	-	-	-	-	**$3.358**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$5.805	$0.186	-	-	-	-	-	-	**$5.992**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.299	$0.051	-	-	-	-	-	-	**$2.350**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.299	$0.051	-	-	-	-	-	-	**$2.350**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$4.194	$0.135	-	-	-	-	-	-	**$4.330**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$4.194	$0.135	-	-	-	-	-	-	**$4.330**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	By reducing the IT labor needed to keep the system current and patched, the Company will avoid approximately $100,000 annually. This shift allows personnel to focus on other priorities and other technology investments.
Avoided Costs	By utilizing a vendor SaaS applications, the Company can avoid costs associated with purchasing hardware and software. Additionally, expenses related to maintenance and asset refreshes will be avoided.
Risk Mitigation	Since the Company adopted a cloud-first strategy, the Company will avoid costs associated with traditional infrastructure. This move to a vendor SaaS will also enhance uptime (SLA of 99.95%), reliability, and scalability, aligning perfectly with the Company's strategic goals thus shifting risk to the vendor.
Intangibles	The Cloud will provide improved response, issue resolution by product vendor, and higher platform availability.

ISIS Papyrus 2026 Upgrade

Report Pulled: 4/14/2026 **Item ID: 13461**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ISIS Papyrus Upgrade, ISIS Papyrus 2026 Upgrade

Description This project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The ISIS Papyrus application is critical to creating electronic and paper correspondence for customers, including bills and dunnings.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement The application will be at least one major upgrade revision behind by 2026. It's imperative that customers retain unfettered access to their paper bills, dunning notices and other communications produced by ISIS. ISIS also makes customer bills available for online viewing through the website and mobile apps. Without the upgrade, vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity and security will be forthcoming. The upgrade will address these problems and challenges, as well as ensuring all other platform components comply with the Company's operational and security standards.

Objectives The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors.

Scope The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications.

Alternatives Alternatives considered include: (1) delaying the upgrade and continuing to operate with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching. (2) The Company instead decided to upgrade to the current version. This alternative was chosen as it eliminates the risk of application instability and the inability to maintain cyber security patching.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2026	3/1/2026	4/1/2026	6/1/2026
	In-Service/Go-Live	**Closeout**	
	9/1/2026	10/1/2026	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.217	-	-	-	-	-	-	-	$0.217
Total Cost of Ownership	$0.217	-	-	-	-	-	-	-	**$0.217**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.203	-	-	-	-	-	-	-	**$0.203**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.014	-	-	-	-	-	-	-	**$0.014**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.217	-	-	-	-	-	-	-	**$0.217**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.217	-	-	-	-	-	-	-	**$0.217**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.217	-	-	-	-	-	-	-	**$0.217**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	An out-of-support version of Papyrus Designer means that ISIS Papyrus no longer provides hotfix support. This will put the company network at risk, which is critical to avoid as this is responsible for paper billing.

OTHER VALUE

Type	Description
Intangibles	Newer versions of ISIS Papyrus enable better integration with newest operating systems (Linux) and database (SQL).
Intangibles	Newer versions of ISIS Papyrus will improve performance and enhance productivity for billing and invoices.

ISIS Papyrus 2028 Upgrade

Report Pulled: 4/14/2026 **Item ID: 13980**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ISIS Papyrus Upgrade, ISIS Papyrus 2026 Upgrade, ISIS Papyrus 2028 Upgrade

Description This project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The ISIS Papyrus application is critical to creating electronic and paper correspondence for customers, including bills and dunnings.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement It's imperative that customers retain unfettered access to their paper bills, dunning notices and other communications produced by ISIS. ISIS also makes customer bills available for online viewing through the website and mobile apps. Without the upgrade, vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity and security will be forthcoming. The upgrade will address these problems and challenges, as well as ensuring all other platform components comply with the Company's operational and security standards.

Objectives The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors.

Scope The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications.

Alternatives Alternatives considered include: (1) delaying the upgrade and continuing to operate with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching. (2) The Company instead decided to upgrade to the current version. This alternative was chosen as it eliminates the risk of application instability and the inability to maintain cyber security patching.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2028	2/1/2028	4/1/2028	6/1/2028
	In-Service/Go-Live	**Closeout**	
	9/1/2028	10/1/2028	

FUNDING SUMMARY

	2028	2029	2030	2031	2032	2033	2034	2035 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.202	-	-	-	-	-	-	-	$0.202
Total Cost of Ownership	$0.202	-	-	-	-	-	-	-	**$0.202**

	2028	2029	2030	2031	2032	2033	2034	2035 +	Total
Labor	$0.189	-	-	-	-	-	-	-	**$0.189**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.013	-	-	-	-	-	-	-	**$0.013**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.202	-	-	-	-	-	-	-	**$0.202**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2028	2029	2030	2031	2032	2033	2034	2035 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.202	-	-	-	-	-	-	-	**$0.202**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.202	-	-	-	-	-	-	-	**$0.202**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	An out-of-support version of Papyrus Designer means that ISIS Papyrus no longer provides hotfix support. This will put the company network at risk, which is critical to avoid as this is responsible for paper billing.

OTHER VALUE

Type	Description
Intangibles	Newer versions of ISIS Papyrus enable better integration with newest operating systems (Linux) and database (SQL).
Intangibles	Newer versions of ISIS Papyrus will improve performance and enhance productivity for billing and invoices.

Itron Enterprise Edition 2027 Upgrade

Report Pulled: 4/14/2026 **Item ID:** 13415

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Itron Enterprise Edition Upgrade 2028, Itron Enterprise Edition 2028 Upgrade, Itron Enterprise Edition 2030 Upgrade, Itron Enterprise Edition 2028 Upgrade, Itron Enterprise Edition 2027 Upgrade

Description This project will upgrade Itron Enterprise Edition (IEE), which collects the reads from meters to ensure non-estimated bill accuracy.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement Itron Enterprise Edition (IEE) is the Company's keystone application of the Advanced Metering Infrastructure (AMI), that provides billing data that includes time of use data. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. Itron Enterprise Edition (IEE) is a key component in keeping the Company current, with billing capacity, stability, and accuracy obligations.

Objectives This project creates value for the Company by: (1) ensuring the features and functionality needed to meet and exceed customer satisfaction and billing accuracy are available to business partners and IT; (2) meeting Information Security's requirement to keep applications patched and protected from cyber attack.

Scope The scope of this project includes: (1) upgrading the Itron Enterprise Edition (IEE) applications to the next appropriate versions; (2) migrating the database to the next version required by the application; and (3) replacing hardware required by the next version to maintain operating system currency.

Alternatives Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because it would decouple Itron IEE (Consumers Energy's Meter Data Management) from the Itron security infrastructure introducing application instability, security and dependency risks to the utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Itron applications, creating more expense to support and no ability to leverage updated tool capability. (2) replacing the platform. Replacing IEE/MDM would require the application business owners to undertake a new initiative mirroring the expense and effort that went into the initial multi-million dollar project.(3) performing the upgrade is the best alternative. This option is superior for both customers and the Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/14/2027	2/16/2027	2/28/2027	4/14/2027
	In-Service/Go-Live	**Closeout**	
	10/20/2027	11/14/2027	

FUNDING SUMMARY

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.266	-	-	-	-	-	-	-	$0.266
Total Cost of Ownership	$0.266	-	-	-	-	-	-	-	**$0.266**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.249	-	-	-	-	-	-	-	**$0.249**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.017	-	-	-	-	-	-	-	**$0.017**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.266	-	-	-	-	-	-	-	**$0.266**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.266	-	-	-	-	-	-	-	**$0.266**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.266	-	-	-	-	-	-	-	**$0.266**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	If Consumers Energy does not upgrade this equipment, it would run the risk of losing support from the vendor, leading to security vulnerabilities and operational efficiency issues.
Risk Mitigation	Without the upgrade, supportability and operational efficiency issues may increase over time. Resolving these issues becomes very problematic if vendor support is not available. It would also be difficult to keep the system current with security updates.

Kubra 4.0 Upgrade

Report Pulled: 4/16/2026 | Item ID: 14018

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow | **Work Type** Project

Alias , Kubra 4.0 Upgrade

Description Consumers Energy (CE) has the overarching ambition of serving 1 in 3 Low-to-Moderate Income (LMI) customers (currently 1 in 6), while supporting the achievement of clean energy goals and reduction in Uncollectible Expense (UCX). 37% of CE customers are low to moderate income (LMI). Low Income (LI) accounts for 11% and means they are currently in crisis and unable to pay their bill. Moderate Income (MI) accounts for 26% and means they are one financial crisis away from being unable to pay their bill. As part of the LMI effort, we are prioritizing Behavior Based Direct Messaging: Meet the customer where they are, communicate about assistance options based on behavioral indicators, and increase the likelihood of enrollment into meaningful assistance programs ahead of a crisis, and Kubra 4.0 will aid in the success of those LMI goals.

Portfolio Customer Services > Customer Interaction Channels > Digital > Digital Operations > * > *

Org CX&T | **Bus Unit** INFORMATION TECHNOLOGY | **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement To help a customer avoid a crisis before it happens, we need the ability to proactively communicate to them when their behaviors signal the possibility of an issue, some examples being: (1) A customer misses a payment after record of making payments for several months, (2) The auto-pay system receives an insufficient funds alert from the customers' account, (3) Energy use is high, and a bill is projected to be 25-50% larger than usual, and (4) Localized / seasonal triggers such as heat waves, blizzards, and ice storms. Additionally, (5) it's imperative that we're able to test and modify message content that captures the customer's attention, so that we may drive awareness to programs that offer assistance ahead of a crisis. Kubra 4.0 platform is more flexible and configurable to help experimental design & marketing iterate on who/where/what to cut through digital noise.

Objectives This project creates value for the Company through improving customer communications by providing Consumers Energy (CE) with access to (1) templates and wording changes that previously required expensive Statement of Work (SOW) engagement to deliver and (2) reduce lengthy wait times to implement these aforementioned Statements of Work (SOWs). Finally, (3) this engagement will also introduce 12 net new alert messages, (4) allow for new means of communication and messaging via the mobile app push notification feature, and (5) provide better outage notification reliability and control via Application Programming Interface (API) data transfer instead of Secure File Transfer Protocol (SFTP) data transfer.

Scope The project scope includes: (1) 12 net new alerts including 4 for the Shut-off Protection Plan (SPP), missed payment(s), summer event alerting, winter event alerting, and 5 additional alerts to be detailed out during the plan & design phase of the effort based on current low-to-moderate income (LMI) customer communication needs, (2) new template editor as part of the upgraded platform, (3) New Push Notification option available for mobile app which will enable a fast follow enhancement to push notifications through more than just email and text, (4) all other updates and improvements through Kubra 4.0 including use of APIs and other technical improvements, and (5) a new Application Programming Interface (API) built specifically for CE's outage messages for better reliability - instead of the existing file transfer outage information which is less reliable.

Alternatives The alternatives considered include: (1) continue the expensive Statements of Work (SOW) approach for updating each message template and for bringing on any new messages. This would total approximately ~50k per new alert, for a total of 600k for all 12 net new alerts for this effort if pursued individually. This total is not including costs to any existing message adjustments. This alternative was not considered due to the extra cost and overhead. (2) Purchase a new customer communications system. This option was not selected as it would be extremely expensive to purchase and wouldn't have all of the requirements needed and would be a tremendous amount of labor to reintegrate with our existing communication channels. (3) Utilizing Microsoft Dynamics or Riverstar. This option was not selected as it would be a tremendous amount of labor to reintegrate with our existing communication channels nor would either of the platforms fully support the bandwidth or channels needed to properly communicate out what we send via Kubra today. (4) Implement the upgrade to include the new alerts. This alternative was selected because it will improve customer communications, improve accuracy and speed of message updates, and offer more message options to achieve the Low-to-Moderate income (LMI) 1-in-3 goal as we're able to keep expanding our communication options with the upgrade's features.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/4/2025	3/20/2025	5/1/2025	10/17/2025
	In-Service/Go-Live	**Closeout**	
	11/20/2025	12/1/2025	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.328	$0.007	-	-	-	-	-	-	$0.336
O&M	-	-	-	-	-	-	-	-	-
Total Cost of Ownership	$0.328	$0.007	-	-	-	-	-	-	**$0.336**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.277	$0.005	-	-	-	-	-	-	**$0.282**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.052	$0.002	-	-	-	-	-	-	**$0.054**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.328	$0.007	-	-	-	-	-	-	**$0.336**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.328	$0.007	-	-	-	-	-	-	**$0.336**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.328	$0.007	-	-	-	-	-	-	**$0.336**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	Medium	Medium	If we do not update the system, it could pose risk to the stability of existing alerts
Technology Obsolescence	High	High	risk to app currency eventually/tech dept to not be able to use api eventually

OTHER VALUE

Type	Description

Live Wiredown Detection and ADMS Upgrade

Report Pulled: 4/15/2026 **Item ID: 10474**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Live Wiredown Detection, ADMS 3.4 Upgrade & Live Wiredown Detection, Live Wiredown Detection and ADMS Upgrade

Description The Live Wiredown Detection and ADMS Upgrade project, formerly known as Live Wire Down, enables, configures, tests, and implements an add-on module to the ADMS/Electra outage management system that provides the Company with the information on whether a wiredown has a live conductor or not, enabling dispatchers to prioritize truck-rolls and wire-guards to the live wiredowns first. The module provides this information based on any smart meter events being reported from behind that conductor. An upgrade to the ADMS system to the next version 3.4 is required to enable the Live Wiredown Detection module. The ADMS 3.4 version also contains several other functional enhancements the benefit the overall Electric service restoration process.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement Currently, the Company does not have the ability to remotely determine if a reported wire down is live. Therefore, the Company has to send truck-rolls to secure every location. Sometimes, it is a waste of time and resources for the public safety teams (police & fire) guarding a downed wire that may already be de-energized. There is no way currently to determine the priority of which wiredown the restoration team should be tending to. There are major public safety concerns around wire down operations as well as the logistics of team safety during wiredown operations. The Live Wiredown Detection module from the vendor requires an upgrade to version 3.4 of the current ADMS software. Therefore, this project would warrant an upgrade of the existing version 3.2 to new version 3.4 of the ADMS software, which itself comes with new functionality and several enhancements.

Objectives The project will add value by: (1) reducing the number of truck-rolls, (2) relieving public safety personnel from downed wires quicker, (3) reducing the size of the wire down operations teams, (4) decreasing wiredown secure times, (5) implementing the ability to prioritize wiredowns, (6) gaining efficiency in resourcing and less time spent troubleshooting, (7) meeting MPSC-regulatory standards, and (8) creating the ability to reduce isolating and enable restore or repair safer, faster, and cheaper.

Scope The scope of the project includes: (1) upgrade of the existing version 3.2 to new version 3.4 of the ADMS software, (2) turning on the "Live wire conductor" and other new functionality in the ADMS system, (3) testing the new functionality in various possible scenarios, (4) enabling the wiredown tool and other enhancements for all Low-Voltage Distribution (LVD) locations across the Company, and (5) communicating and training users on the new functionality.

Alternatives The alternatives considered are: (1) Developing an in-house application that provides process improvements. This option was not selected as it requires the Company to design and build the algorithm that the Electric Power Research Institute (EPRI) has already devised, and then integrate with the OMS system; (2) Using the LVD line sensors (to be deployed in 5 years) to provide some of the functionality. This option was not selected as the benefits realization would be much delayed; (3) Maintaining the current truck-roll process. This option was not selected due to the specific MPSC-regulatory standard expectations and the safety implications of doing nothing; and (4) Enabling and implementing the live wiredown module for OMS. This option of enabling and implementing the live wiredown module for OMS integrates with the new OMS system and is based on the algorithms that EPRI has already designed. This option was chosen as it has the least technology and integration risk, which avoids the need for the Company to develop their own logic and algorithm for live wiredown detection.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/5/2023	8/1/2023	9/1/2023	8/1/2024
	In-Service/Go-Live	**Closeout**	
	9/30/2024	12/20/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.288	$1.275	-	-	-	-	-	-	$1.563
O&M	$0.024	$0.022	$0.142	$0.010	$0.010	$0.010	-	-	$0.217
Total Cost of Ownership	$0.312	$1.298	$0.142	$0.010	$0.010	$0.010	-	-	**$1.780**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.072	$0.763	$0.113	-	-	-	-	-	**$0.948**
Outside Services	$0.076	$0.308	$0.020	-	-	-	-	-	**$0.404**
Business Expense/Overheads	$0.016	$0.226	$0.008	-	-	-	-	-	**$0.250**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.003	-	-	-	-	-	-	-	**$0.003**
Licenses, Permits & Fees	$0.146	$0.000	-	$0.010	$0.010	$0.010	-	-	**$0.174**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.312	$1.298	$0.142	$0.010	$0.010	$0.010	-	-	**$1.780**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.024	$0.022	$0.142	$0.010	$0.010	$0.010	-	-	**$0.217**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.024	$0.022	$0.142	$0.010	$0.010	$0.010	-	-	**$0.217**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.288	$1.275	-	-	-	-	-	-	**$1.563**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.288	$1.275	-	-	-	-	-	-	**$1.563**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	$1.59M in avoided costs due to reduced truck rolls, by being able to differentiate between Live downed wire vs. a de-energized wire
Avoided Costs	$310,000 per year savings due to reduced Wire Down Operations Staffing
Avoided Costs	$47,000 per year savings due to reduced training re-qualification for wire guards
Risk Mitigation	Reduces the safety risk for employees and public by allowing prioritization of Live wiredowns over others, so they could be addressed first
Intangibles	The target is to secure Police/Fire wire downs within 4 hours 90% of the time in a year (reference MPSC rule 460.723), we are currently at 88.3% (2019), and with this implementation we will meet or exceed 90%. - PLACEHOLDER FOR PERFORMANCE METRIC

MS Self-hosted Gateway Solution and Migration

Report Pulled: 4/15/2026 **Item ID:** 14008

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Tibco Api Migration Zone B, MS Self-hosted Gateway Solution and Migration

Description This project is looking to retire the Application Programming Interfaces (API) Exchange Gateway used primarily by the Enterprise Service Bus and replace it with a new solution called Microsoft Self-Hosted Gateway in security Zone B. The API Exchange Gateway is used by The Information Bus Company Enterprise Service Bus (TIBCO ESB) to integrate corporate applications. New development will need to be done to integrate this solution.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement The TIBCO API Exchange Gateway is anticipated to be sunset by the vendor, as they have already dropped all development of enhancements for the platform. The end of life date is 6/30/25

Objectives This project creates value for the Company by: (1) Avoiding the risk of running a project no longer supported by the vendor (i.e. the TIBCO API Exchange Gateway Exchange module), and (2) Enabling the Company the opportunity to move to a product that is more stable, secure, and usable.

Scope The project scope includes: (1) Implement the Self Hosted Gateway into Zone B as a replacement solution. (2) Migrate all current work items to the new platform or existing equivalent based on use case. (3) Conduct appropriate testing to ensure all Service Level Agreements are met.

Alternatives Alternatives considered include: (1) Evaluating the replacement of the current product with a new product that is not already in the Company environment. This alternative was not selected because it would not be cost effective. (2) Keeping the current application as-is. This alternative was not selected as the vendor for the current platform has stopped all development for this product and the end of life has been set (3) Leveraging an existing solution already in the Company environment. This alternative was not selected as an existing product in the corporate Zone B layer does not exist. (4) Implement the Microsoft Self-Hosted Gateway and migrate current data into new platform. This alternative was selected as the most cost-effective solution that has ongoing support from the publisher.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/12/2026	1/19/2026	3/6/2026	3/9/2026
	In-Service/Go-Live	**Closeout**	
	10/10/2026	10/23/2026	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.289	-	-	-	-	-	-	-	$0.289
Total Cost of Ownership	$0.289	-	-	-	-	-	-	-	**$0.289**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.279	-	-	-	-	-	-	-	**$0.279**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.010	-	-	-	-	-	-	-	**$0.010**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.289	-	-	-	-	-	-	-	**$0.289**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.289	-	-	-	-	-	-	-	**$0.289**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.289	-	-	-	-	-	-	-	**$0.289**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	Due to Technology obsolesces, if this solution is not implemented, the company runs the risk of technology reliability issues to the platform and other connected applications. Current Vendor has stopped with updates for security and corrective patches. Which causes increased security vulnerability to the platform and integrated applications.

OTHER VALUE

Type	Description

Operational Technology (OT) Datacenter Migration

Report Pulled: 4/15/2026 **Item ID:** 13963

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , OT Datacenter Colo, OT Datacenter Migration, Operational Technology Datacenter Migration, Operational Technology (OT) Datacenter Migration

Description The OT environment consists of systems supporting the control and monitoring of electric grid, electric generation, gas compression, and natural gas pipeline. These systems are critical for safe and reliable natural gas and electric delivery. The OT Datacenter Migration project enhances the Company's capabilities by co-locating to an enhanced datacenter at a vendor facility.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement The Company's current datacenter for the OT environment needs modernization and relocation from the Parnall Data Center. The current location is not the preferred location to house servers and systems critical to the control of the Electric Grid or Gas Pipeline due to the close proximity to a railway system. The climate conditioners in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns . The location of the datacenter in the basement of the Parnall building is nearby to the main water piping for the building. There have been instances of water infiltration in the past.

Objectives This project creates value for the Company by significantly strengthening capabilities through: (1) mitigating legacy physical and location risks at the current Parnall site; (2) migrating the OT infrastructure to a modern, highly secured environment with redundancy in climate conditions; and (3) better datacenter facilities support with a guarantee of redundant power.

Scope The scope of the project includes: (1) migration of the OT environment from the Parnall Data Center to a co-located vendor data center; (2) re-validation of the OT Production and Disaster Recovery procedures once migration is completed; (3) migration of IT systems required for supporting the OT environment; and (4) decommission the existing OT environment from the Parnall location.

Alternatives The Company performed an analysis of alternatives to expand capabilities as well as address constraints and risks: (1) Remain at the current Parnall Data Center; (2) migrate OT environments to the Cloud; and (3) relocate to a third-party co-location facility. Current industry best practices do not recommend migration of OT environments to the cloud. The co-location vendor provides the building, cooling, power, and physical security the Company lacks for its servers, storage, and other computing and networking equipment at the current Parnall location. Based on the analysis, the Company decided to implement the third alternative.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
6/30/2026	9/8/2026	11/24/2026	1/15/2027
	In-Service/Go-Live	**Closeout**	
	11/16/2027	12/1/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$4.391	$3.358	-	-	-	-	-	-	$7.750
O&M	$2.311	$3.985	$1.816	$1.816	-	-	-	-	$9.928
Total Cost of Ownership	$6.702	$7.343	$1.816	$1.816	-	-	-	-	**$17.677**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.492	$0.658	-	-	-	-	-	-	**$1.150**
Outside Services	$0.864	$1.221	-	-	-	-	-	-	**$2.085**
Business Expense/Overheads	$1.828	$1.656	-	-	-	-	-	-	**$3.484**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$3.199	$1.811	-	-	-	-	-	-	**$5.010**
Licenses, Permits & Fees	$0.319	$0.181	-	-	-	-	-	-	**$0.500**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$6.702	$5.527	-	-	-	-	-	-	**$12.229**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.311	$3.985	$1.816	$1.816	-	-	-	-	**$9.928**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.311	$3.985	$1.816	$1.816	-	-	-	-	**$9.928**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$4.391	$3.358	-	-	-	-	-	-	**$7.750**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$4.391	$3.358	-	-	-	-	-	-	**$7.750**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	The Company would be able to avoid ARP-OT Support Common and ARP-OT Support Electric project costs in future years. of the following amounts. ARP-OT Support Common $809,200 Capital and $83,440 O&M and ARP-OT Support-Electric $828,600 Capital and $87,8120 O&M
Risk Mitigation	The presence of a railway near a data center increases physical risk such as vibration and environmental hazards such as trains carrying hazardous material or fuels. A more recent Industry standard, ANSI/BICSI 002-2024, recommends maintaining a safe distance – typically 1.6 km (1 mi) or more – to ensure long-term stability and minimize risk. The current distance from the railway to the building, where the data center is located, is approximately 170 meters. The OT Data Center migration project will mitigate this risk and follow industry guidelines for safe distance to railroads
Intangibles	There could be impacts to business services, customer service, and Company reputation.
Risk Mitigation	There is a need for enhancement to Consumer Energy's DR capabilities. Without a clear understanding of the risks, mitigation of those risks, and communication to all key stakeholders, the Company may not be able to recover from a loss of the primary data centers at Parnall. This risk may result in impacts to day-to-day operations and customers, which could have broader financial, reputational, and regulatory impacts.
Avoided Costs	This project will avoid the costs of addressing aging climate control and continuing water filtration issues. The Company has estimated the costs of addressing the aging climate control equipment and continuing water filtration issues of the current location to be $5,082,728. The projected costs to replace the aging climate control equipment including labor is $4,965,728. To remediate the water infiltration issues which would require removal of architectural concrete and replacing the waterproof membrane, which is estimated to be $117,000. This does not address the risk of the datacenter location being in the basement of the Parnall building near the main water pipe for the building. By moving the data center to a new co-located facility, this cost would be avoided and mitigate the risk of the location of the datacenter being near the main water pipe for the building
Risk Mitigation	Using a vendor managed co-location datacenter reduces Company risk as it relates to NERC/CIP regulatory requirement Physical Security CIP-006-6
Intangibles	With the OT Datacenter migration, there is a highly secured environment, heating and cooling redundancy, and a guarantee of 100% power efficiency.

Privileged Access Management Cloud Migration

Report Pulled: 4/14/2026 **Item ID:** 14035

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Private Access Cloud Migration, Privileged Access Management Cloud Migration

Description This project will perform the implementation of a Privileged Access Management (PAM) solution to enhance security by securely storing, rotating, and isolating privileged credentials for both human and non-human users. It provides robust monitoring and control of privileged access across on-premises, cloud, and hybrid environments. Additionally, it automates password management, reducing administrative tasks and minimizing the risk of credential exposure.

Portfolio Corporate Services > Security Services > Cyber Security & Shared Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAND/

WORK OBJECTIVES

Problem Statement The Company faces significant security risks related to the management of privileged access, including potential data breaches, unauthorized access, and compliance issues. The Company's current methods of managing privileged accounts are often manual, error-prone, and insufficient to address the complexities of modern IT environments. There is a critical need for a robust solution that can automate and secure the management of privileged credentials, provide comprehensive monitoring and control, and ensure compliance with security policies across on-premises, cloud, and hybrid environments.

Objectives This project creates value for the Company through: (1) securely storing and managing privileged credentials; (2) automating credential rotation; (3) isolating access to prevent unauthorized use; (4) improving compliance with regulatory requirements through comprehensive audit trails, and reporting; (5) increasing efficiency by automating password management; and (6) reducing manual tasks that can be prone to human error.

Scope The project scope includes migrating the Company's current system Privileged Access Management (PAM) system to a cloud vendor, implementing new features not available in the current on-prem solution.

Alternatives Alternatives considered included: (1) manual password rotation. This alternative was not chosen because it requires significant time and effort to manage and update passwords manually. It also increases the risk of human error including mistakes, such as forgetting to update passwords or using predictable patterns; (2) Access Control Lists (ACLs). This alternative was not chosen because of scalability issues. ACLs are difficult to manage as the number of users and resources grows. This option also requires regular updates and reviews to ensure accuracy and security; (3) manual audit logs. This alternative was not chosen because it is very labor intensive. It requires significant effort to maintain and review logs manually. The use of manual audit logs increases the risk of inaccuracy by having a higher chance of errors and incomplete records; (4) periodic security reviews. This alternative was not chosen because it is very resource intensive and requires time and expertise to conduct thorough reviews. Periodic security reviews may also miss issues that arise between review periods; and (5) implementation of a cloud based Privileged Access Management (PAM) solution was the chosen option. It provides robust monitoring and control of privileged access across on-premises, cloud, and hybrid environments. Additionally, it automates password management, reducing administrative tasks and minimizing the risk of credential exposure.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/16/2027	2/13/2027	3/13/2027	10/22/2027
	In-Service/Go-Live	**Closeout**	
	10/23/2027	11/27/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	$2.410	-	-	-	-	-	-	$2.410
O&M	-	$0.351	-	-	-	-	-	-	$0.351
Total Cost of Ownership	-	$2.760	-	-	-	-	-	-	**$2.760**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	-	$0.138	-	-	-	-	-	-	**$0.138**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	$0.597	-	-	-	-	-	-	**$0.597**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$2.025	-	-	-	-	-	-	**$2.025**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$2.760	-	-	-	-	-	-	**$2.760**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.351	-	-	-	-	-	-	**$0.351**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.351	-	-	-	-	-	-	**$0.351**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$2.410	-	-	-	-	-	-	**$2.410**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$2.410	-	-	-	-	-	-	**$2.410**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Improve compliance with regulatory requirements for privileged access through comprehensive audit trails, and reporting.
Technology Capability	Increasing efficiency by automating password management for privileged access accounts.
Technology Capability	Isolate privileged access to prevent unauthorized use.
Technology Capability	Securely storing and managing privileged credentials will prevent unauthorized use.

Product Family Enhancements-Application Platforms Services-Ca Report Pulled: 4/14/2026 Item ID: 13931

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Portfolio

Alias , Product Family Enhancements-IT/Digital Foundation-Capital, Product Family Enhancements-Application Platforms and Services, Product Family Enhancements-Application Platforms and Services-Capital, Product Family Enhancements-Application Platforms Services-Capital

Description The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.293	$0.940	$0.311	$0.311	$0.311	$0.311	$0.311	-	$2.790
O&M	$0.060	$0.188	$0.031	$0.031	$0.031	$0.031	$0.031	-	$0.401
Total Cost of Ownership	$0.353	$1.128	$0.342	$0.342	$0.342	$0.342	$0.342	-	**$3.191**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.269	$0.789	$0.121	$0.121	$0.121	$0.121	$0.121	-	**$1.663**
Outside Services	$0.018	-	$0.124	$0.124	$0.124	$0.124	$0.124	-	**$0.637**
Business Expense/Overheads	$0.048	$0.340	$0.068	$0.068	$0.068	$0.068	$0.068	-	**$0.729**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.008	$0.008	$0.008	$0.008	$0.008	-	**$0.041**
Licenses, Permits & Fees	$0.019	-	$0.020	$0.020	$0.020	$0.020	$0.020	-	**$0.121**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.353	$1.128	$0.342	$0.342	$0.342	$0.342	$0.342	-	**$3.191**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.060	$0.188	$0.031	$0.031	$0.031	$0.031	$0.031	-	**$0.401**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.060	$0.188	$0.031	$0.031	$0.031	$0.031	$0.031	-	**$0.401**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.293	$0.940	$0.311	$0.311	$0.311	$0.311	$0.311	-	**$2.790**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.293	$0.940	$0.311	$0.311	$0.311	$0.311	$0.311	-	**$2.790**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Application Platforms Services-O Report Pulled: 4/14/2026 Item ID: 13933

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-IT/Digital Foundation-O&M, Product Family Enhancements-Application Platforms and Services-O&M, Product Family Enhancements-Application Platforms Services-O&M

Description The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.102	$0.170	$0.157	$0.157	$0.157	$0.157	$0.157	-	$1.056
Total Cost of Ownership	$0.102	$0.170	$0.157	$0.157	$0.157	$0.157	$0.157	-	**$1.056**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.094	$0.159	$0.076	$0.076	$0.076	$0.076	$0.076	-	**$0.633**
Outside Services	-	-	$0.063	$0.063	$0.063	$0.063	$0.063	-	**$0.315**
Business Expense/Overheads	$0.003	$0.011	$0.005	$0.005	$0.005	$0.005	$0.005	-	**$0.040**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.005	-	-	-	-	-	-	-	**$0.005**
Licenses, Permits & Fees	-	-	$0.013	$0.013	$0.013	$0.013	$0.013	-	**$0.064**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.102	$0.170	$0.157	$0.157	$0.157	$0.157	$0.157	-	**$1.056**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.102	$0.170	$0.157	$0.157	$0.157	$0.157	$0.157	-	**$1.056**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.102	$0.170	$0.157	$0.157	$0.157	$0.157	$0.157	-	**$1.056**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Corporate-Capital

Report Pulled: 4/14/2026 **Item ID:** 13372

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Corporate-Capital

Description The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services.

Scope The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.665	$1.115	$1.032	$1.032	$1.032	$1.032	$1.032	-	$6.940
O&M	$0.003	$0.249	$0.074	$0.074	$0.074	$0.074	$0.074	-	$0.623
Total Cost of Ownership	$0.668	$1.364	$1.106	$1.106	$1.106	$1.106	$1.106	-	**$7.563**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.569	$0.960	$0.224	$0.224	$0.224	$0.224	$0.224	-	**$2.649**
Outside Services	-	-	$0.613	$0.613	$0.613	$0.613	$0.613	-	**$3.065**
Business Expense/Overheads	$0.098	$0.403	$0.117	$0.117	$0.117	$0.117	$0.117	-	**$1.087**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	-	**$0.015**
Licenses, Permits & Fees	$0.001	-	$0.149	$0.149	$0.149	$0.149	$0.149	-	**$0.747**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.668	$1.364	$1.106	$1.106	$1.106	$1.106	$1.106	-	**$7.563**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.003	$0.249	$0.074	$0.074	$0.074	$0.074	$0.074	-	**$0.623**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.003	$0.249	$0.074	$0.074	$0.074	$0.074	$0.074	-	**$0.623**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.665	$1.115	$1.032	$1.032	$1.032	$1.032	$1.032	-	**$6.940**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.665	$1.115	$1.032	$1.032	$1.032	$1.032	$1.032	-	**$6.940**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Corporate-O&M

Report Pulled: 4/15/2026 **Item ID:** 13373

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Corporate-O&M

Description The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services.

Scope The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.385	$0.258	$0.353	$0.353	$0.353	$0.353	$0.353	-	$2.409
Total Cost of Ownership	$0.385	$0.258	$0.353	$0.353	$0.353	$0.353	$0.353	-	**$2.409**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.363	$0.241	$0.091	$0.091	$0.091	$0.091	$0.091	-	**$1.057**
Outside Services	-	-	$0.247	$0.247	$0.247	$0.247	$0.247	-	**$1.233**
Business Expense/Overheads	$0.022	$0.017	$0.016	$0.016	$0.016	$0.016	$0.016	-	**$0.119**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.385	$0.258	$0.353	$0.353	$0.353	$0.353	$0.353	-	**$2.409**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.385	$0.258	$0.353	$0.353	$0.353	$0.353	$0.353	-	**$2.409**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.385	$0.258	$0.353	$0.353	$0.353	$0.353	$0.353	-	**$2.409**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Customer-Capital

Report Pulled: 4/20/2026 **Item ID:** 13374

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Customer-Capital

Description The Customer initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$2.491	$2.777	$2.564	$2.284	$2.284	$2.284	$2.284	-	$16.967
O&M	$0.417	$0.196	$0.600	$0.544	$0.544	$0.544	$0.544	-	$3.390
Total Cost of Ownership	$2.908	$2.973	$3.164	$2.828	$2.828	$2.828	$2.828	-	**$20.357**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$2.481	$0.447	$0.669	$0.444	$0.444	$0.444	$0.444	-	**$5.372**
Outside Services	-	$2.380	$2.022	$1.971	$1.971	$1.971	$1.971	-	**$12.284**
Business Expense/Overheads	$0.292	$0.138	$0.414	$0.354	$0.354	$0.354	$0.354	-	**$2.260**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	-	**$0.054**
Licenses, Permits & Fees	$0.135	-	$0.051	$0.051	$0.051	$0.051	$0.051	-	**$0.388**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$2.908	$2.973	$3.164	$2.828	$2.828	$2.828	$2.828	-	**$20.357**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.417	$0.196	$0.600	$0.544	$0.544	$0.544	$0.544	-	**$3.390**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.417	$0.196	$0.600	$0.544	$0.544	$0.544	$0.544	-	**$3.390**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.491	$2.777	$2.564	$2.284	$2.284	$2.284	$2.284	-	**$16.967**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.491	$2.777	$2.564	$2.284	$2.284	$2.284	$2.284	-	**$16.967**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Customer-O&M

Report Pulled: 4/16/2026 **Item ID:** 13375

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Customer-O&M

Description The Customer initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.147	$0.300	$0.235	$0.235	$0.235	$0.235	$0.235	-	$1.621
Total Cost of Ownership	$0.147	$0.300	$0.235	$0.235	$0.235	$0.235	$0.235	-	**$1.621**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.001	$0.179	$0.059	$0.059	$0.059	$0.059	$0.059	-	**$0.476**
Outside Services	$0.146	$0.102	$0.163	$0.163	$0.163	$0.163	$0.163	-	**$1.061**
Business Expense/Overheads	-	$0.020	$0.013	$0.013	$0.013	$0.013	$0.013	-	**$0.084**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.147	$0.300	$0.235	$0.235	$0.235	$0.235	$0.235	-	**$1.621**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.147	$0.300	$0.235	$0.235	$0.235	$0.235	$0.235	-	**$1.621**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.147	$0.300	$0.235	$0.235	$0.235	$0.235	$0.235	-	**$1.621**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Electric & Gas Shared-Capital

Report Pulled: 4/15/2026 **Item ID:** 13376

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Electric & Gas Shared-Capital

Description The Electric and Gas operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in Electric and Gas operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Companys ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$3.360	$1.037	$1.826	$1.826	$1.826	$1.826	$1.826	-	$13.528
O&M	$0.485	$0.155	$0.308	$0.308	$0.308	$0.308	$0.308	-	$2.179
Total Cost of Ownership	$3.845	$1.192	$2.134	$2.134	$2.134	$2.134	$2.134	-	**$15.707**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$1.373	$0.155	$0.358	$0.358	$0.358	$0.358	$0.358	-	**$3.320**
Outside Services	$2.093	$0.843	$1.574	$1.574	$1.574	$1.574	$1.574	-	**$10.804**
Business Expense/Overheads	$0.247	$0.179	$0.157	$0.157	$0.157	$0.157	$0.157	-	**$1.212**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.132	$0.015	$0.045	$0.045	$0.045	$0.045	$0.045	-	**$0.371**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$3.845	$1.192	$2.134	$2.134	$2.134	$2.134	$2.134	-	**$15.707**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.485	$0.155	$0.308	$0.308	$0.308	$0.308	$0.308	-	**$2.179**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.485	$0.155	$0.308	$0.308	$0.308	$0.308	$0.308	-	**$2.179**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$3.360	$1.037	$1.826	$1.826	$1.826	$1.826	$1.826	-	**$13.528**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$3.360	$1.037	$1.826	$1.826	$1.826	$1.826	$1.826	-	**$13.528**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Electric & Gas Shared-O&M

Report Pulled: 4/20/2026 **Item ID:** 13377

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Electric & Gas Shared-O&M

Description The Electric and Gas operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations.

Scope The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Companys ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$1.465	$0.216	$0.566	$0.566	$0.566	$0.566	$0.566	-	$4.511
Total Cost of Ownership	$1.465	$0.216	$0.566	$0.566	$0.566	$0.566	$0.566	-	**$4.511**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.344	$0.154	$0.062	$0.062	$0.062	$0.062	$0.062	-	**$0.809**
Outside Services	$0.679	$0.046	$0.490	$0.490	$0.490	$0.490	$0.490	-	**$3.176**
Business Expense/Overheads	$0.443	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	-	**$0.525**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.002	-	-	-	-	-	-	**$0.002**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.465	$0.216	$0.566	$0.566	$0.566	$0.566	$0.566	-	**$4.511**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.465	$0.216	$0.566	$0.566	$0.566	$0.566	$0.566	-	**$4.511**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.465	$0.216	$0.566	$0.566	$0.566	$0.566	$0.566	-	**$4.511**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Electric-O&M

Report Pulled: 4/15/2026 **Item ID:** 13379

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Electric-Capital, Product Family Enhancements-Electric-O&M

Description The Electric/Generation/Renewables Engineering and Operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in Electric/Generation/Renewables Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric/Generation/Renewables Engineering and Operations.

Scope The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric/Generation/Renewables Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.114	$0.259	$0.120	$0.120	$0.120	$0.120	$0.120	-	$0.975
Total Cost of Ownership	$0.114	$0.259	$0.120	$0.120	$0.120	$0.120	$0.120	-	**$0.975**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.108	$0.206	$0.046	$0.046	$0.046	$0.046	$0.046	-	**$0.546**
Outside Services	-	$0.036	$0.066	$0.066	$0.066	$0.066	$0.066	-	**$0.366**
Business Expense/Overheads	$0.005	$0.017	$0.006	$0.006	$0.006	$0.006	$0.006	-	**$0.051**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	$0.002	$0.002	$0.002	$0.002	$0.002	-	**$0.011**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.114	$0.259	$0.120	$0.120	$0.120	$0.120	$0.120	-	**$0.975**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.114	$0.259	$0.120	$0.120	$0.120	$0.120	$0.120	-	**$0.975**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.114	$0.259	$0.120	$0.120	$0.120	$0.120	$0.120	-	**$0.975**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Electric-Capital

Report Pulled: 4/14/2026 **Item ID:** 13378

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Electric-Capital

Description The Electric/Generation/Renewables Engineering and Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in Electric/Generation/Renewables Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric/Generation/Renewables Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric/Generation/Renewables Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.631	$0.920	$0.719	$0.719	$0.719	$0.719	$0.719	-	$5.148
O&M	$0.057	$0.183	$0.189	$0.189	$0.189	$0.189	$0.189	-	$1.183
Total Cost of Ownership	$0.689	$1.103	$0.908	$0.908	$0.908	$0.908	$0.908	-	**$6.332**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.288	$0.475	$0.192	$0.192	$0.192	$0.192	$0.192	-	**$1.724**
Outside Services	$0.328	$0.345	$0.607	$0.607	$0.607	$0.607	$0.607	-	**$3.709**
Business Expense/Overheads	$0.072	$0.283	$0.108	$0.108	$0.108	$0.108	$0.108	-	**$0.897**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.001	-	-	-	-	-	-	**$0.001**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.689	$1.103	$0.908	$0.908	$0.908	$0.908	$0.908	-	**$6.332**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.057	$0.183	$0.189	$0.189	$0.189	$0.189	$0.189	-	**$1.183**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.057	$0.183	$0.189	$0.189	$0.189	$0.189	$0.189	-	**$1.183**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.631	$0.920	$0.719	$0.719	$0.719	$0.719	$0.719	-	**$5.148**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.631	$0.920	$0.719	$0.719	$0.719	$0.719	$0.719	-	**$5.148**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Infrastructure Platforms Service

Report Pulled: 4/14/2026 **Item ID:** 13934

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-IT/Digital Foundation-O&M, Product Family Enhancements-Application Platforms and Services-O&M, Product Family Enhancements-Infrastructure Platforms and Services-O&M, Product Family Enhancements-Infrastructure Platforms Services-O&M

Description The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS & SI

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.041	$0.047	$0.073	$0.073	$0.073	$0.073	$0.073	-	$0.455
Total Cost of Ownership	$0.041	$0.047	$0.073	$0.073	$0.073	$0.073	$0.073	-	**$0.455**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.028	$0.044	$0.009	$0.009	$0.009	$0.009	$0.009	-	**$0.116**
Outside Services	$0.012	-	$0.062	$0.062	$0.062	$0.062	$0.062	-	**$0.324**
Business Expense/Overheads	$0.001	$0.003	$0.002	$0.002	$0.002	$0.002	$0.002	-	**$0.013**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	$0.000	$0.000	$0.000	$0.000	$0.000	-	**$0.002**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.041	$0.047	$0.073	$0.073	$0.073	$0.073	$0.073	-	**$0.455**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.041	$0.047	$0.073	$0.073	$0.073	$0.073	$0.073	-	**$0.455**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.041	$0.047	$0.073	$0.073	$0.073	$0.073	$0.073	-	**$0.455**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Infrastructure Platforms Services- Report Pulled: 4/14/2026 Item ID: 13932

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Portfolio

Alias , Product Family Enhancements-IT/Digital Foundation-Capital, Product Family Enhancements-Application Platforms and Services, Product Family Enhancements-Infrastructure Platforms and Services-Capital, Product Family Enhancements-Infrastructure Platforms Services-Capital

Description The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software & hardware and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS & S

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.196	$0.589	$0.403	$0.403	$0.403	$0.403	$0.359	-	$2.755
O&M	$0.105	$0.201	$0.130	$0.130	$0.130	$0.130	$0.130	-	$0.957
Total Cost of Ownership	$0.301	$0.790	$0.533	$0.533	$0.533	$0.533	$0.489	-	**$3.712**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.132	$0.572	$0.193	$0.193	$0.193	$0.193	$0.193	-	**$1.668**
Outside Services	$0.066	-	$0.194	$0.194	$0.194	$0.194	$0.194	-	**$1.038**
Business Expense/Overheads	$0.036	$0.218	$0.095	$0.095	$0.095	$0.095	$0.095	-	**$0.728**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.067	-	$0.048	$0.048	$0.048	$0.048	$0.003	-	**$0.261**
Licenses, Permits & Fees	$0.001	-	$0.003	$0.003	$0.003	$0.003	$0.003	-	**$0.017**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.301	$0.790	$0.533	$0.533	$0.533	$0.533	$0.489	-	**$3.712**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.105	$0.201	$0.130	$0.130	$0.130	$0.130	$0.130	-	**$0.957**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.105	$0.201	$0.130	$0.130	$0.130	$0.130	$0.130	-	**$0.957**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.196	$0.589	$0.403	$0.403	$0.403	$0.403	$0.359	-	**$2.755**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.196	$0.589	$0.403	$0.403	$0.403	$0.403	$0.359	-	**$2.755**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Public Key Infrastructure (PKI) Upgrade

Report Pulled: 4/14/2026 **Item ID:** 13691

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Public Key Infrastructure (PKI) Upgrade

Description Replace on-premise PKI to stay supported by the manufacturer.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAND/

WORK OBJECTIVES

Problem Statement The existing PKI that issues certificates to IT systems for secure communications needs to be upgraded to stay supported by the manufacturer. If the PKI is not maintained, in the event of a system failure the Company would not have support in recovering. All IT systems requiring secure communications via certificates would go offline within three days.

Objectives Replace existing PKI with new PKI that is supported by the manufacturer.

Scope The project will build and configure the servers necessary to provide Public Key Infrastructure services, put in place physical token management for maintaining security, migrate certificate issuing and management to the new system and decommission the old system.

Alternatives The Company has a limited use service for PKI on the Internet only. (1) The Company looked into expanding the service to include usage on the Company network but found the solution to not be economically viable. (2) The Company also looked at full cloud solutions, but it did not meet the security standards currently being used around physical token use. (3) The Company looked at continuing extended support, however the continuing extended support is not available by the vendor. (4) The Company selected a hybrid solution of part cloud and part on-premise to meet all operational and security compliance requirements. The opportunity is to retain ownership of the keys on-premise prior to evaluating ownership through the cloud.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
10/9/2023	10/23/2023	12/4/2023	12/15/2023
	In-Service/Go-Live	**Closeout**	
	7/1/2024	7/12/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.154	$1.234	$0.200	-	-	-	-	-	$1.588
O&M	$0.084	$0.188	$0.137	-	-	-	-	-	$0.410
Total Cost of Ownership	$0.238	$1.422	$0.337	-	-	-	-	-	**$1.998**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.015	$0.239	$0.001	-	-	-	-	-	**$0.255**
Outside Services	$0.016	$0.267	$0.285	-	-	-	-	-	**$0.567**
Business Expense/Overheads	$0.002	$0.135	$0.027	-	-	-	-	-	**$0.164**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.672	$(0.026)	-	-	-	-	-	**$0.646**
Licenses, Permits & Fees	$0.205	$0.109	$0.051	-	-	-	-	-	**$0.366**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.238	$1.422	$0.337	-	-	-	-	-	**$1.998**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.084	$0.188	$0.137	-	-	-	-	-	**$0.410**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.084	$0.188	$0.137	-	-	-	-	-	**$0.410**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.154	$1.234	$0.200	-	-	-	-	-	**$1.588**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.154	$1.234	$0.200	-	-	-	-	-	**$1.588**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
System Failure (SAP & Other)	High	Medium	Consumers Energy's vendor, Thales only offers full support for seven years after purchase of a solution. After the end of support no more operational or security patches are available and if an issue is encountered the manufacturer will not assist in resolving.

OTHER VALUE

Type	Description
Risk Mitigation	DR Risks/Impacts Description – If the Company doesn't upgrade to a supported version and the system becomes unrecoverable, we are at risk of the of the following: (1) Lost productivity of approximately 8,000 employees and 4,000 contractors who are unable to access system is estimated to be 3.12M (Half day – 13,000 *$60 *4 hours) to 12.48M (2 days – 13,000 people * $60 * 16 hours). (2) Deferred revenue – payment from customers estimated to be $12-44M daily. (3) Life Safety Incidents – loss of ability to report a down powerline, gas leak type events. (4) Negatively impacts our ability to assist with Storm Restoration. (5) Call centers will go down.
Risk Mitigation	The Company's research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; (2) avert customer frustration and employee downtime; (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities; (4) continue operating system support as older versions are retired by the manufacturer; and (5) ensure employees have the required software to perform their work.

Ransomware Recovery-OT-Electric & Generation

Report Pulled: 4/15/2026 **Item ID:** 13428

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Ransomware Recovery, Ransomware Recovery - OT, Ransomware Recovery - OT - Electric & Generation, Ransomware Recovery-OT-Electric & Generation

Description This project will implement a multi-layered security approach to our Operational Technology (OT) data center backups to mitigate data loss risk from a ransomware attack for OT.

Portfolio IT Services > Infrastructure > Data Center - Storage > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement As an American energy provider, the company is at an increased risk of ransomware attacks by nation-states and other advanced threat actors. A severe ransomware attack could leave the Company without access to critical data or processes and little to no ability to recover the associated systems and information. In a best-case scenario, a successful ransomware attack would likely result in primary systems outages, severely limiting our capability to provide services to our customers, for up to a week and could result in months of work to recover auxiliary systems.

Objectives This project will add value to the Company, and its customers, by: (1) Implementing a 3-2-1-1 (3 copies, 2 media, 1 offline, 1 immutable) strategy to protect the production data center systems, data, and backups from ransomware and broader potential cyber-attacks; (2) Providing a diverse set of restoration options to reduce data loss and improve the recovery time of mission-critical systems; (3) Mitigating the risk of complete data loss by storing backups offline and in a format that cannot be modified by any threat (internal or external); (4) Defining an Operational Technology (OT) specific ransomware recovery plan that the Company can use to respond to a wide array of cyber-attacks with a practiced process; and (5) Providing the ability for OT to sever all communications from the industrial control systems to the public internet and corporate Informational Technology (IT) networks.

Scope The scope of this project is to deliver one-day of hardware storage level recovery points, local immutable copies of production OT data, an offline third copy of production OT data, and deliver a ransomware recovery plan with a scenario-based approach to ransomware response including plans for monitoring, testing, containment, ransomware/malware removal, and full system recovery.

Alternatives The alternatives considered include: (1) Paying the associated ransom, a plan to pay the ransom introduces unnecessary risk by either trusting the attacker to provide the encryption keys while taking a financial loss or the regulatory ramifications such action would result in. (2) Restoring from tape is a possibility but significantly increases Operational Technology's (OT) restoration times in the event of a severe ransomware attack (over one week to restore mission-critical systems). (3) Primary restoration from the public cloud was considered but delivery would have been extremely complex and capabilities are limited in ransomware recovery situations due to public internet connections being severed to the OT datacenter when a ransomware attack is identified (Island Protocol). (4) The alternative chosen was to host ransomware capabilities in the Consumers Energy (CE) OT datacenter, with the exception of the 3rd data copy being hosted in the public cloud. This solution provides enhanced recovery times and uninhibited restoration of mission critical systems.

DATES (phase end)

Initiation 1/2/2024	**Project Plan & Scope Definition** 1/15/2024	**Final Engineering, Planning & Design** 1/31/2024	**Execution** 2/1/2024
	In-Service/Go-Live 3/31/2025	**Closeout** 4/30/2025	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.574	$4.723	$0.618	$(0.131)	-	-	-	-	$5.785
O&M	-	$0.034	$0.138	$0.412	$0.437	$0.462	$0.229	-	$1.712
Total Cost of Ownership	$0.574	$4.756	$0.756	$0.282	$0.437	$0.462	$0.229	-	**$7.496**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.037	$0.240	$0.356	$(0.032)	-	-	-	-	**$0.601**
Outside Services	$0.405	$0.089	$0.013	$0.026	-	-	-	-	**$0.533**
Business Expense/Overheads	$0.015	$0.068	$0.081	$(0.012)	-	-	-	-	**$0.152**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.117	$1.201	$0.155	$(0.113)	-	-	-	-	**$1.360**
Licenses, Permits & Fees	-	$3.159	$0.098	-	-	-	-	-	**$3.256**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.574	$4.756	$0.701	$(0.130)	-	-	-	-	**$5.902**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.034	$0.138	$0.412	$0.437	$0.462	$0.229	-	**$1.712**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.034	$0.138	$0.412	$0.437	$0.462	$0.229	-	**$1.712**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.574	$4.723	$0.618	$(0.131)	-	-	-	-	**$5.785**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.574	$4.723	$0.618	$(0.131)	-	-	-	-	**$5.785**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Loss of Data Center - Parnall	High	Low	This should be tied to the Data Loss Corporate Risk. This project reduces the risk by ensuring we have a secure version of production data in the event of ransomware attack.
System Failure (SAP & Other)	Low	Low	Without the full project implementation, maintenance may need to be renewed for up to $1.2M on equipment that is not currently planned in the ITPM.

OTHER VALUE

Type	Description

Rate Change Maintenance

Report Pulled: 4/14/2026 **Item ID: 13957**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias Rates Case Implementation, Rate Cases Annual Upgrade Implementation, Rate Cases Annual Upgrade, Rate Case Annual Upgrade, Rate Case Annual Requirements, Rate Case Maintenance, Rate Change Maintenance

Description The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements.

Portfolio IT Services > Applications > Customer Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement For the Company to continue to meet and comply with certain MPSC requirements and to enable it to update its rates when rate changes are approved, there is a need to make periodic updates/modifications to existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers.

Objectives The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that includes new surcharges, price changes, and energy efficiency programs.

Scope The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Company's back-end system for more efficient rate changes.

Alternatives Alternative considered include: (1) a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and the time it would take for testing of this model; and (2) Instead, the Company chose to leverage onshore resources to plan, coordinate, and execute the rate changes. This option was selected as it supports the Company's operation model for rate changes.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.325	$0.246	$0.299	$0.299	$0.299	$0.299	$0.299	-	$2.065
Total Cost of Ownership	$0.325	$0.246	$0.299	$0.299	$0.299	$0.299	$0.299	-	**$2.065**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.307	$0.230	$0.004	$0.004	$0.004	$0.004	$0.004	-	**$0.556**
Outside Services	-	-	$0.277	$0.277	$0.277	$0.277	$0.277	-	**$1.385**
Business Expense/Overheads	$0.018	$0.016	$0.018	$0.018	$0.018	$0.018	$0.018	-	**$0.124**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.325	$0.246	$0.299	$0.299	$0.299	$0.299	$0.299	-	**$2.065**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.325	$0.246	$0.299	$0.299	$0.299	$0.299	$0.299	-	**$2.065**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.325	$0.246	$0.299	$0.299	$0.299	$0.299	$0.299	-	**$2.065**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Completing timely rate changes reduces the risk of increasing noncollectable revenue due to delays with rate implementation. The Company could risk millions of dollars if rate changes are delayed; establishing an optimized process for rate changes is crucial to mitigate this risk.
Avoided Costs	Following the Rate Optimization implementation the team responsible for rate changes can streamline their efforts; preventing waste in the form of waiting and rework. Multiple changes can be completed at once versus sequencing them which causes rework when priorities shift.
Risk Mitigation	Maintain compliance by fulfilling MPSC rates requirements, ensuring customer bills remain accurate as the Company implements various rate changes. This will help the Company provide the best rates for customers as they're identified.

SAP HANA Database Migration

Report Pulled: 4/15/2026 **Item ID: 11774**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , SAP HANA Database Migration

Description In preparation for SAP's planned end of support for its Business Suite product in 2027, the Company will migrate its existing SAP databases from Oracle to SAP HANA in advance of the required move to S/4HANA.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement The Company's SAP applications currently utilize Oracle's relational database management system as their underlying database storage technology. SAP has informed its customers that standard support for its legacy Business Suite (aka ECC) product will end in 2027, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the company will migrate all of its SAP databases off of Oracle and onto SAP HANA.

Objectives This project lays the groundwork for the company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027.

Scope Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures and tools required to manage the newly migrated SAP HANA applications.

Alternatives Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering no other options for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform a direct migration from SAP Business Suite on Oracle to S/4HANA. A direct migration to S/4HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application's functionality would change simultaneously, so this alternative was not selected. (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S/4HANA. It will also require the Company to accept significant risk due to the fact that SAP security patches, application patches and upgrades will not be available upon termination of the SAP maintenance agreement. (3) Migrate to SAP's Software as a Service (SaaS) implementation of S/4HANA. This alternative was not selected because an S/4HANA SaaS migration is a much more disruptive option as the Company's business processes must be adjusted to accommodate functionality differences between ECC and S/4HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. (4) Migrate the SAP databases to HANA prior to implementing S/4HANA. This alternative was selected as it gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process changes required with S/4HANA.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/3/2023	7/31/2023	10/2/2023	1/2/2024
	In-Service/Go-Live	**Closeout**	
	11/1/2025	12/2/2025	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$2.392	$2.841	$3.431	-	-	-	-	-	$8.663
O&M	$0.181	$0.840	$0.409	-	-	-	-	-	$1.430
Total Cost of Ownership	$2.572	$3.681	$3.839	-	-	-	-	-	**$10.093**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.101	$0.592	$2.060	-	-	-	-	-	**$2.754**
Outside Services	$0.180	$2.146	$0.069	-	-	-	-	-	**$2.395**
Business Expense/Overheads	$0.035	$0.285	$0.217	-	-	-	-	-	**$0.537**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$2.255	$0.659	$1.494	-	-	-	-	-	**$4.408**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$2.572	$3.681	$3.839	-	-	-	-	-	**$10.093**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	$(1.096)	$(1.096)	-	-	-	**$(2.192)**
	Initial	$0.181	$0.840	$0.409	-	-	-	-	-	**$1.430**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.181	$0.840	$0.409	$(1.096)	$(1.096)	-	-	-	**$(0.762)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.392	$2.841	$3.431	-	-	-	-	-	**$8.663**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.392	$2.841	$3.431	-	-	-	-	-	**$8.663**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.831

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	By completing this work in advance of December 2027, when SAP will cease support of its Business Suite (ECC) product, and by performing this work in a phased approach (migrating to HANA database first, before migrating the application to S/4HANA), the Company avoids potential operational stability issues.

SAP Support Pack Upgrade 2026

Report Pulled: 4/14/2026 **Item ID: 12501**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , SAP Support Pack Upgrade 2025, SAP Support Pack Upgrade 2026

Description The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for business partners.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability.

Objectives The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility.

Scope The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component (ECC), Customer Relationship Manager (CRM), Enterprise Portal, Process Orchestration (PO), Business Warehouse (BW), Business Objects (BOBJ), Data Services (DS), Solution Manager, Data Quality Manager (DQM), Graphical User Interface (GUI), Single Sign On (SSO), System Landscape Directory (SLD) and other related SAP applications.

Alternatives Alternatives considered include: (1) dividing the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) migrating to SAP S/4HANA. This option was not selected because SAP S/4HANA is a multi-year project that is not expected to be completed by year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3) Ultimately, the Company chose to balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2026	4/1/2026	6/1/2026	7/1/2026
	In-Service/Go-Live	**Closeout**	
	10/15/2026	10/31/2026	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.454	-	-	-	-	-	-	-	$0.454
Total Cost of Ownership	$0.454	-	-	-	-	-	-	-	**$0.454**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.064	-	-	-	-	-	-	-	**$0.064**
Outside Services	$0.361	-	-	-	-	-	-	-	**$0.361**
Business Expense/Overheads	$0.030	-	-	-	-	-	-	-	**$0.030**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.454	-	-	-	-	-	-	-	**$0.454**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.454	-	-	-	-	-	-	-	**$0.454**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.454	-	-	-	-	-	-	-	**$0.454**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Ensure all SAP applications are compatible with each other.
Intangibles	Ensure all SAP applications are fully supported by SAP.
Risk Mitigation	Risk mitigation by ensuring all SAP applications have the latest patches and bug fixes.

SAP Support Pack Upgrade 2028

Report Pulled: 4/15/2026 **Item ID: 13442**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , SAP Support Pack Upgrade 2025, SAP Support Pack Upgrade 2026, SAP Support Pack Upgrade 2028

Description The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for business partners.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability.

Objectives The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility.

Scope The scope of this project includes routine support pack upgrades to all SAP applications, which include: Customer Relationship Manager (CRM), Enterprise Portal, Process Orchestration (PO), Business Warehouse (BW), Business Objects (BOBJ), Data Services (DS), Governance, Solution Manager, Data Quality Manager (DQM), System Landscape Directory (SLD) and other related SAP applications.

Alternatives Alternatives considered include: (1) dividing the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) migrating to SAP S/4HANA. This option was not selected because SAP S/4HANA is a multi-year project that is not expected to be completed by year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3) Ultimately, the Company chose to balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2028	4/1/2028	6/1/2028	7/1/2028
	In-Service/Go-Live	**Closeout**	
	10/15/2028	10/31/2028	

FUNDING SUMMARY

	2028	2029	2030	2031	2032	2033	2034	2035 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.462	-	-	-	-	-	-	-	$0.462
Total Cost of Ownership	$0.462	-	-	-	-	-	-	-	**$0.462**

	2028	2029	2030	2031	2032	2033	2034	2035 +	Total
Labor	$0.065	-	-	-	-	-	-	-	**$0.065**
Outside Services	$0.367	-	-	-	-	-	-	-	**$0.367**
Business Expense/Overheads	$0.030	-	-	-	-	-	-	-	**$0.030**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.462	-	-	-	-	-	-	-	**$0.462**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2028	2029	2030	2031	2032	2033	2034	2035 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.462	-	-	-	-	-	-	-	**$0.462**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.462	-	-	-	-	-	-	-	**$0.462**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Ensure all SAP applications are compatible with each other.
Intangibles	Ensure all SAP applications are fully supported by SAP.
Risk Mitigation	Risk mitigation against system & information security issues by ensuring all SAP applications have the latest security patches and bug fixes.

Saviynt Enterprise Identity Governance and Access (EIGA) Impl

Report Pulled: 4/14/2026 **Item ID:** 13302

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Access Now Upgrade 2023, Access Now Upgrade 2024, Saviynt EIGA Implementation, Saviynt Enterprise Identity Governance and Access (EIGA) Implementation

Description The project will implement Saviynt EIGA module, consolidate Identity Access Management (IAM) functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAND/

WORK OBJECTIVES

Problem Statement The current version of AccessNow reached end of life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and customizations. While beneficial for end users, these integrations increase the risk of system failures, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduces failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention.

Objectives The current version of AccessNow reached end of life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and customizations. While beneficial for end users, these integrations increase the risk of system failures, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduces failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention.

Scope This project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Standardizing processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access system; (4) Addressing issues with aging applications, multiple IAM platforms, integration challenges, and antiquated HR processing.

Alternatives Alternatives considered include: (1) Implementing hot fixes to AccessNow version 8.1.5 to ensure support through mid-2023; (2) Upgrading only the application to current supported version, excluding the new web portal but will include new application functionality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break/fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating AccessNow software.

DATES (phase end)

Initiation 3/1/2024	**Project Plan & Scope Definition** 4/5/2024	**Final Engineering, Planning & Design** 6/15/2024	**Execution** 8/1/2024
	In-Service/Go-Live 5/29/2026	**Closeout** 6/30/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$2.795	$1.984	$1.274	-	-	-	-	-	$6.053
O&M	$0.236	$0.278	$0.060	$0.765	$0.765	$0.765	$0.765	-	$3.634
Total Cost of Ownership	$3.031	$2.262	$1.334	$0.765	$0.765	$0.765	$0.765	-	**$9.687**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.390	$1.256	$0.281	-	-	-	-	-	**$1.927**
Outside Services	$0.410	$0.770	$0.600	-	-	-	-	-	**$1.781**
Business Expense/Overheads	$0.179	$0.225	$0.404	-	-	-	-	-	**$0.808**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.050	-	-	-	-	-	**$0.050**
Licenses, Permits & Fees	$2.051	$0.010	-	-	-	-	-	-	**$2.061**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.031	$2.262	$1.334	-	-	-	-	-	**$6.627**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.236	$0.278	$0.060	$0.765	$0.765	$0.765	$0.765	-	**$3.634**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.236	$0.278	$0.060	$0.765	$0.765	$0.765	$0.765	-	**$3.634**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.795	$1.984	$1.274	-	-	-	-	-	**$6.053**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.795	$1.984	$1.274	-	-	-	-	-	**$6.053**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Administrative and General (A&G) Support

Security/OT Field Modernization

Report Pulled: 4/15/2026 **Item ID: 13949**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Security/OT Field Modernization

Description This project will implement new infrastructure for accomplishing improved security in the field for OT assets.

Portfolio IT Services > Infrastructure > * > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERVI

WORK OBJECTIVES

Problem Statement Gas and Electric technicians are using corporate laptops, to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. Vendors and contractors have access to the Company's critical infrastructure using non-Company laptops. Best practice is to use dedicated laptops to connect to critical infrastructure.

Objectives The value of this project is deploying dedicated Company OT laptops and associated OT infrastructure that can move between OT locations only and providing a secure environment.

Scope This project will procure and configure approximately 130 devices that will be used to manage critical OT infrastructure.

Alternatives The Company reviewed several options to mitigate cyber security risks inherent with the use of standard corporate laptops managing critical infrastructure. The alternatives considered are: (1) Continue utilizing existing workflow of using Corporate domain laptops with software installed; (2) Bring in an outside vendor to design and implement a proposed infrastructure; (3) Complete disallowance of all local access to critical systems; (4) Extending the OT network to remote Company locations; (5) Deploy a dedicated Company OT laptop and OT communications circuits, which includes cellular connectivity. The dedicated OT laptop and communications circuits presented the best way to secure the critical infrastructure by limiting internet and e-mail access. Vendors and contractors could also utilize these approved dedicated systems for managing infrastructure they help support at Company locations. Based on the analysis performed, the Company chooses to deploy a dedicated OT laptop and communications circuits which is not a cloud related solution, since it is hardware and not software.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/13/2025	3/7/2025	4/30/2025	6/30/2025
	In-Service/Go-Live	**Closeout**	
	3/1/2026	6/1/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$1.161	$0.943	-	-	-	-	-	-	$2.103
O&M	$0.322	$0.474	$0.294	$0.294	$0.294	$0.294	-	-	$1.971
Total Cost of Ownership	$1.483	$1.416	$0.294	$0.294	$0.294	$0.294	-	-	**$4.074**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.256	$0.743	-	-	-	-	-	-	**$0.999**
Outside Services	$0.119	$0.328	-	-	-	-	-	-	**$0.447**
Business Expense/Overheads	$0.062	$0.116	-	-	-	-	-	-	**$0.178**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.810	-	-	-	-	-	-	-	**$0.810**
Licenses, Permits & Fees	$0.237	$0.025	-	-	-	-	-	-	**$0.262**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.483	$1.212	-	-	-	-	-	-	**$2.695**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.322	$0.474	$0.294	$0.294	$0.294	$0.294	-	-	**$1.971**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.322	$0.474	$0.294	$0.294	$0.294	$0.294	-	-	**$1.971**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.161	$0.943	-	-	-	-	-	-	**$2.103**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.161	$0.943	-	-	-	-	-	-	**$2.103**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	By utilizing dedicated Operational Technology (OT) laptops without internet or e-mail access, we are mitigating the risk of a device with internet and e-mail access compromising the critical infrastructure at various Electric and Gas sites while connecting to critical control systems.
Risk Mitigation	Mandating vendors to use a dedicated Consumers Energy devices to connect to CE industrial infrastructure mitigates risk to critical systems from unknown and untrusted devices.
Intangibles	There could be impacts to business services, customer service, and Company reputation.

Service Restoration Artificial Intelligence

Report Pulled: 4/14/2026 **Item ID: 14031**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Service Restoration Artificial Intelligence, Service Restoration Artificial Intelligence Solution, Service Restoration Artificial Intelligence

Description Artificial Intelligence (AI) Machine Learning (ML) can enhance decision-making during restoration events by quickly evaluating multiple datasets, reduce non-value-added time, and continuously improve through learning. This project will show the value of AI ML in Storm Declarations, Resource Planning, Resource Utilization/Crew Movements, and Asset Identification.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The Company faces challenges in efficiently managing storm response and restoration efforts. Historically, storm declarations, resource planning, and crew movements have relied on manual processes and estimations, leading to delays and inefficiencies. The need for a more effective and timely response during restoration events has become increasingly critical, especially given the complexity and scale of modern storm events.

Objectives This project creates value for the Company by (1) enhancing the storm response capabilities. This will enable faster and more consistent decision-making during restoration events, optimizing resource planning and crew movement and improving asset identification. (2) Delivering business value. The utilization of AI ML in service restoration processes is expected to reduce non-value-added time, improve public safety and create savings for customers. (3) Providing customer value. The AI ML applications will benefit customers by optimizing storm declarations, resource planning, crew movement and asset identification. These enhancements will lead to more efficient outcomes, faster restoration times and improved public safety. Furthermore, AI ML's learning abilities enable the decision-making to continuously improve, and those learnings have the durability to live beyond the human experience and mitigate learning curves as people transition from role to role.

Scope The project scope includes: (1) developing AI ML models for storm declarations, resource planning, resource utilization/crew movements, and asset identification. (2) Integrating with existing systems like Advanced Distribution Management System (ADMS), Customer Resource Manager (CRM) and Catastrophic Crewing in house built application. (3) Training and deploying. (4) Performance monitoring and (5) customer communication.

Alternatives Alternatives considered include: (1) continuing with the manual process. This option was not chosen because it results in underutilized crews, non-value-added time, and increased human error and difficulty. (2) Purchasing a storm work management solution. This option was not chosen due to its high cost, vendor dependency during the Company's most critical times, and complexity. (3) Creating an AI ML solution. This option was selected as it meets the criteria and will be scalable across service restoration and electric distribution.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
3/1/2026	4/1/2026	5/31/2026	3/30/2027
	In-Service/Go-Live	**Closeout**	
	4/30/2027	5/30/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$0.884	$0.497	-	-	-	-	-	-	$1.380
O&M	$0.110	$0.060	-	-	-	-	-	-	$0.170
Total Cost of Ownership	$0.994	$0.556	-	-	-	-	-	-	**$1.550**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.680	$0.380	-	-	-	-	-	-	**$1.060**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.314	$0.176	-	-	-	-	-	-	**$0.490**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.994	$0.556	-	-	-	-	-	-	**$1.550**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.110	$0.060	-	-	-	-	-	-	**$0.170**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.110	$0.060	-	-	-	-	-	-	**$0.170**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.884	$0.497	-	-	-	-	-	-	**$1.380**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.884	$0.497	-	-	-	-	-	-	**$1.380**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Freeing up workforce for more value add activities
Avoided Costs	Saving 4 hours each storm with an estimated of 7 storms impacted by savings each year. 4 hour costs of a large storm ~$700k x 7 storms = $4.9m annually

SiteCore Primary Upgrade 2025

Report Pulled: 4/14/2026 **Item ID: 12727**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , SiteCore Upgrade 2025, SiteCore Primary Upgrade 2025

Description The project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for the consumersenergy.com website, a channel many customers use for accessing account information and bill payment.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement Sitecore is currently operating on version 10.3, which is due to end mainstream support at the end of 2025. If this occurs, there will be an increase in support and maintenance fees of 10% above the annual subscription spend in order to purchase extended support, security updates and fixes will only be made available if the extended support is purchased, and product support for errors or required hotfixes that may impact platform stability will not be available even if extended support is purchased.

Objectives The project will add value for the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to-date security posture; and (3) supporting the Company's CXI goals by improving reliability and performance.

Scope The project scope includes: (1) upgrading the Sitecore content management software to include content hosting and delivery allowing the use of new features and functionality; (2) migrating the Sitecore platform to the most up-to-date "hardware" and software by refreshing the application and database servers to a newer version of Windows Server and SQL Server and placing them into Azure Cloud (PaaS & IaaS); (3) implementing autoscaling App Services within Azure to reduce or increase the amount of compute we are paying for based on the need of the customers (i.e. more compute during storm).

Alternatives Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the current version falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Migrate to Sitecore's cloud SaaS solution. This alternative was not chosen due to the cost/benefit analysis of re-architecting our current Sitecore implementation to facilitate use of their SaaS/PaaS not being viable at this time; and (3) Upgrade Sitecore on a two-year cycle. This alternative was chosen as it provides up-to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/15/2025	3/22/2025	5/24/2025	9/30/2025
	In-Service/Go-Live	**Closeout**	
	10/1/2025	10/16/2025	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.077	-	-	-	-	-	-	-	$0.077
Total Cost of Ownership	$0.077	-	-	-	-	-	-	-	**$0.077**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.067	-	-	-	-	-	-	-	**$0.067**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.003	-	-	-	-	-	-	-	**$0.003**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.007	-	-	-	-	-	-	-	**$0.007**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.077	-	-	-	-	-	-	-	**$0.077**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.077	-	-	-	-	-	-	-	**$0.077**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.077	-	-	-	-	-	-	-	**$0.077**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Avoid the cost of purchasing extended support from the vendor which comes at a 10% increase from normal licensing costs.
Risk Mitigation	If this project is not completed the company and the customers are at greater risk of encountering more reliability issues and cyber threats which could compromise the website. Keeping the Sitecore platform up to date will improve overall performance and reduce likelihood of operational issues. Additionally, the risk of cyber threats is reduced as patches and fixes are released on routine schedules.
Risk Mitigation	If website is either unavailable or not performing sufficiently, it will lead to a negative impact to Consumers Energy reputations with customers and lower JD Power scores. The website is a core contact point for the Company to interact with their customers. When Sitecore is not functioning completely the website will be impacted; potentially preventing customers from viewing their bill, make a payment, report an outage, and other functions.

SiteCore Secondary Upgrade 2027

Report Pulled: 4/14/2026 **Item ID: 12740**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias 2017 BizTalk Upgrade, SiteCore Upgrade 2024, SiteCore Upgrade 2023, SiteCore Secondary Upgrade 2023-2024, SiteCore Secondary Upgrade 2026-2027, SiteCore Secondary Upgrade 2027

Description The project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for the consumersenergy.com website, a channel many customers use for accessing account information and bill payment.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement Sitecore requires regular upgrades to adhere to the vendors support lifecycle to ensure system reliability, take advantage of new application features, maintain current security updates, and improve the customer's website experience.

Objectives The project will add value for the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to-date security posture; and (3) supporting the Company's Customer Experience Index (CXI) goals by improving reliability and performance.

Scope The project scope includes: (1) upgrading the Sitecore content management software to the latest available version.

Alternatives Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the need to prevent the application from falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Migrating to a cloud solution was also considered. This alternative was not chosen due to the cost/benefit analysis of re-architecting the Company's current Sitecore implementation to facilitate cloud migration that is not viable at this time; and (3) Rejecting these alternatives, the Company chose to upgrade Sitecore on a two-year cycle because it provides up to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/18/2027	3/22/2027	4/5/2027	9/30/2027
	In-Service/Go-Live	**Closeout**	
	10/1/2027	10/15/2027	

FUNDING SUMMARY

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.106	-	-	-	-	-	-	-	$0.106
Total Cost of Ownership	$0.106	-	-	-	-	-	-	-	**$0.106**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.099	-	-	-	-	-	-	-	**$0.099**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.007	-	-	-	-	-	-	-	**$0.007**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.106	-	-	-	-	-	-	-	**$0.106**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.106	-	-	-	-	-	-	-	**$0.106**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.106	-	-	-	-	-	-	-	**$0.106**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	If this project is not completed the company and the customers are at greater risk of encountering more reliability issues and cyber threats which could compromise the website. Keeping the Sitecore platform up to date will improve overall performance and reduce likelihood of operational issues. Additionally, the risk of cyber threats is reduced as patches and fixes are released on routine schedules.
Risk Mitigation	If website is either unavailable or not performing sufficiently, it will lead to a negative impact to Consumers Energy reputations with customers and lower JD Power scores. The website is a core contact point for the Company to interact with their customers. When Sitecore is not functioning completely the website will be impacted; potentially preventing customers from viewing their bill, make a payment, report an outage, and other functions.

Spatial Asset Management

Report Pulled: 4/14/2026 | Item ID: 13940

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow | **Work Type** Project

Alias , Spatial Asset Management

Description This initiative will implement SAP's Spatial Asset Management module. It will allow users to view assets, notifications, and orders geospatially using a map. The module will allow the Company to create and maintain asset maintenance plans for each segment of our gas and electric distribution networks (linear assets). The Company will create linear assets as technical objects (such as functional locations and equipment) and store linear data. The Company will enable creation of maintenance plans for these technical objects which result in notifications, maintenance orders, and measurement documents. We will enable monitoring the condition of our linear assets, identify where there is damage or a defect (using the start point and end point and offset), and manage all types of maintenance tasks (planned, unplanned, and preventative).

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T | **Bus Unit** INFORMATION TECHNOLOGY | **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement Currently, the Company lacks spatial visualization and spatial awareness of work and assets impacting requirements for first time quality and impacting the ability to plan, bundle and execute nearby work. The lack of a linear asset management capability affects the full work management value stream resulting in overproduction of asset maintenance activity such as assessments, surveys, and inspections.

Objectives This project creates value for the Company by (1) providing capability in SAP to view assets, notifications, and work orders on a map; (2) providing location awareness in SAP for assets and work; (3) establishing linear asset management capability in SAP for gas and electric delivery networks; and (4) enabling end-to-end map-based workflows.

Scope The scope of this project encompasses implementation in SAP of the Spatial Asset Management module.

Alternatives Alternatives considered include: (1) Implement a cloud-based individualized asset integration between GIS and SAP. This alternative was not selected as it proves ineffective in addressing needs of the end-to-end work management value stream while increasing the technical footprint of customization. There are also performance concerns with cloud to on-prem integrations; (2) Implement work group centric approaches to viewing work on a map. This alternative was not selected as it does not support standard operation through the entire work management value stream; (3) Do nothing. This alternative was not selected as this would result in increasing costs and inefficiencies in gas and electric work management; and (4) The alternative to implement the Spatial Asset Management module in SAP was chosen as it expands use of a core technology investment, supports current investment in our work management value stream, and is compatible with our GIS technology.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
12/4/2023	4/30/2024	1/31/2026	2/28/2026
	In-Service/Go-Live	**Closeout**	
	5/1/2026	5/31/2026	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.436	$0.739	$0.330	$0.357	-	-	-	-	$2.862
O&M	-	$0.019	$0.026	$0.226	$0.172	$0.172	$0.172	-	$0.786
Total Cost of Ownership	$1.436	$0.758	$0.355	$0.583	$0.172	$0.172	$0.172	-	**$3.648**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	$0.052	$0.099	$0.120	-	-	-	-	**$0.271**
Outside Services	$0.160	$0.351	$0.095	$0.210	-	-	-	-	**$0.816**
Business Expense/Overheads	$0.100	$0.121	$0.162	$0.080	-	-	-	-	**$0.463**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$1.176	$0.233	-	-	-	-	-	-	**$1.409**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.436	$0.758	$0.355	$0.410	-	-	-	-	**$2.959**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.019	$0.026	$0.226	$0.172	$0.172	$0.172	-	**$0.786**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.019	$0.026	$0.226	$0.172	$0.172	$0.172	-	**$0.786**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.436	$0.739	$0.330	$0.357	-	-	-	-	**$2.862**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.436	$0.739	$0.330	$0.357	-	-	-	-	**$2.862**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	SAM supports a single platform for engineers and designers that consolidates multiple data sources & third-party tools and provides templates to accelerate projects.
Intangibles	SAM supports workflow and collaboration thru smart notifications, annotations, and messaging embedded throughout the platform.

Streetlight Outage and Restoration Optimization

Report Pulled: 4/15/2026 **Item ID: 13926**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Streetlight Outage and Restoration Optimization

Description This project will optimize the Streetlight Outage and Restoration (SOAR) application to better meet our customers need. The SOAR application is used by the Company's customers to report streetlight outages. This project will add new functionality to meet our customers' needs.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement While 98% of our customers are using SOAR to submit issues, between 15-20% of those issues are more than a lightbulb change/luminaire replacement, leading to multiple truck rolls, and work requiring long cycle scheduling. It lacks the most current source data due to manual process of updating the data, automation, and SMS text messaging, which leads to waste and customer dissatisfaction. By integrating these optimizations, Consumers Energy will streamline the work management system, reduce errors and provide a more comprehensive and efficient solution for our customers, our schedulers and our field workers.

Objectives This project creates value for the Company by: (1) improving customer and municipality communications; (2) adding visualizations to improve accuracy and speed of repair; (3) adding field improvements such as getting the issue to the right department the first time and knowing what materials are needed so the light is fixed on the first visit; and (4) automating and updating the map which will allow for more accuracy. All of these will eliminate waste by using automation and properly routing of orders.

Scope The project scope includes: (1) identifying correctly outages versus other work; (2) improving GIS data to include proper stock material and Temporary Traffic Control (TTC) requirements and prioritizing scheduled work based on outage repair needs; (3) offering SMS text messaging; (4) improving email communications by including more accurate details to customers; (5) daily automation of map data updating; (6) adding functionality for user-generated reliability reports; and (7) adding a new process to advise municipality of extended repair outages.

Alternatives

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/3/2025	8/3/2025	9/3/2025	2/20/2026
	In-Service/Go-Live	**Closeout**	
	2/27/2026	3/13/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.653	$1.207	-	-	-	-	-	-	$1.860
O&M	$0.338	$0.140	$0.030	$0.030	-	-	-	-	$0.540
Total Cost of Ownership	$0.991	$1.348	$0.030	$0.030	-	-	-	-	**$2.400**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.041	$0.652	-	-	-	-	-	-	**$0.693**
Outside Services	$0.939	$0.470	-	-	-	-	-	-	**$1.409**
Business Expense/Overheads	$0.011	$0.195	-	-	-	-	-	-	**$0.206**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.991	$1.317	-	-	-	-	-	-	**$2.308**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	$(0.009)	$(0.009)	$(0.009)	-	-	-	-	**$(0.026)**
	Initial	$0.338	$0.140	$0.030	$0.030	-	-	-	-	**$0.540**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.338	$0.132	$0.022	$0.022	-	-	-	-	**$0.514**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.653	$1.207	-	-	-	-	-	-	**$1.860**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.653	$1.207	-	-	-	-	-	-	**$1.860**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.991

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Enhancing this application puts the company in a position to defend streetlight outage percentage. This is a strong tactic to avoid statewide nighttime patrols recommended by rate case interveners. $346,000 of avoided O&M annually.
Intangibles	Implementation will improve streetlight status, giving the customer a more reliable representation of where the work currently is.
Risk Mitigation	Less regulatory risk with these changes. Service Commission has recently required DTE to provide reliability reporting for streetlights. CE will be doing this proactively. This will help improve utility coordination with municipalities.
Risk Mitigation	Proper routing of orders and more accurate communications to our customers will help to mitigate the risk of low Customer Experience index (CXi) and more timely repair time.
Avoided Costs	When this work is completed, trucks will have accurate materials and the Company will be able to streamline temporary traffic control. This will increase productivity and reduce human struggle by being able to quickly route the order to appropriate work center. 30 hours per week efficiency savings. $94.95 hourly. $2,848.50 per week. $148,122 annually.

Talent Management Enablement

Report Pulled: 4/14/2026 **Item ID:** 11828

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Talent Management Enablement

Description The project will deliver technology solutions to enable best-in-class Talent Management programs and processes that are critical to achieve the Company's overarching Talent Strategy Plan. The Talent Strategy Plan is a key enabler of the company's Integrated Resource Plan (IRP), Electric Distribution Infrastructure Investment Plan (EDIIP), and Natural Gas Delivery Plan (NGDP). Effective Talent Management programs and processes are critical to develop the skills, capabilities, productivity, and experience necessary to successfully execute these plans that deliver clean, reliable, affordable energy through an exceptional customer experience.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement Significant technology improvements are required to transform Human Resources (HR) to develop the skills and capabilities necessary to achieve the Company's strategic destination. Currently, many Talent Management processes are manually managed with little or no technology enablement. Specifically, the talent compensation processes are mostly manually done outside the system which introduces waste, and a potential for errors. In addition there is a limited visibility of competency gaps within the workforce. The Company cannot effectively place talent in accelerated development programs aligned to competency gaps, nor can it recognize and motivate employees for quickly increasing competency and performance. Furthermore, the Company operates in an increasingly competitive job market where candidates and employees expect best-in-class processes, technologies and experiences relative to their employment and career development. The lack of full technical enablement across Talent Management programs poses a risk to employee attraction, retention and limits the ability to develop the right skills at the right time to deliver on

Objectives This project will add value to the Company through technology that will enable: (1) fully functional integrated compensation module; (2) accelerated and targeted talent development of critical skills necessary to deliver on the Company's commitment to clean energy and exceptional customer experience; (3) transparency into talent and skill gaps in order to identify retention and service delivery risks within critical areas, as well as inform succession and hiring strategies; (4) improved knowledge transfer, business continuity, and customer service during a time when retirement eligibility is high and risk of knowledge loss has the potential to negatively impact customer service and satisfaction; and (5) increased efficiency and quality of talent management through simplified and automated processes that reduce costs associated with recruiting, onboarding, and developing employees. Talent Management Enablement will deliver the best-practice technology to enable and enhance (1) Fully functional integrated talent compensation management; (2) Simplified and automated talent management process for employee lifecycle management from on-

Scope The scope will include: (1) implementation of each system/application; (2) integration with current systems, applications and processes as applicable; (3) retrofit current systems and applications to ensure a seamless end-to-end experience of HR processes; (4) delivery of mobile capabilities for in scope processes; (5) reporting and analytics dashboards and report insights for in scope processes.

Alternatives Three alternatives were considered for these Talent Management programs and processes: (1) Develop custom, internally built solutions that could meet most requirements. This alternative was not selected because a custom solution would result in higher overall costs, higher maintenance costs, fewer upgrades, and would not leverage industry best practices to ensure best-in-class delivery. (2) Select an on-premise software tool. This alternative was not selected because it requires internal maintenance, increases infrastructure costs, and would have less frequent upgrades which would hinder the Company's ability to ensure processes are evolving alongside industry trends and best practices. (3) Evaluate and select cloud/SaaS solution(s) which would have lower infrastructure costs, less internal maintenance than an on-premise solution, and would be built and evolved with upgrades based on industry best practices. Based on research, internal experience with successful best practice implementations, and vendor demonstrations, option three was selected

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2023	3/1/2023	5/1/2023	7/1/2023
	In-Service/Go-Live	**Closeout**	
	8/30/2025	10/30/2025	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.229	$0.052	$0.096	-	-	-	-	-	$0.377
O&M	$0.204	$0.180	$0.102	$0.100	$0.100	-	-	-	$0.686
Total Cost of Ownership	$0.433	$0.233	$0.198	$0.100	$0.100	-	-	-	**$1.063**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.020	$0.007	$0.114	-	-	-	-	-	**$0.140**
Outside Services	$0.388	$0.225	$0.074	-	-	-	-	-	**$0.687**
Business Expense/Overheads	$0.026	$0.000	$0.010	-	-	-	-	-	**$0.036**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.433	$0.233	$0.198	-	-	-	-	-	**$0.863**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.204	$0.180	$0.102	$0.100	$0.100	-	-	-	**$0.686**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.204	$0.180	$0.102	$0.100	$0.100	-	-	-	**$0.686**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.229	$0.052	$0.096	-	-	-	-	-	**$0.377**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.229	$0.052	$0.096	-	-	-	-	-	**$0.377**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Avoid inability to meet and support quality and timely delivery of the Company's customer centric strategy
Technology Capability	Deliver mobile-enabled Talent Management processes that will facilitate leaders' ability to minimize administrative downtime by increasing accessibility to core talent management processes, forms, approvals, and tracking.
Intangibles	Delivery of best-in-class technically enabled talent programs will enhance the attraction and retention of top talent in an increasingly competitive and geographically expanding job market.
Technology Capability	Eliminate wasted hours associated with the manual management of the Succession Planning process
Risk Mitigation	Mitigate risk due to 19% of the current customer-facing workforce that has 25+ years tenure by enabling effective Talent Management processes to prepare for these retirements to ensure continuation of strong customer delivery by facilitating employee development, engagement, succession planning and performance management
Risk Mitigation	Mitigate the risk of losing high performing talent or not being able to recruit the strongest talent to deliver on company strategies which support customer service and value delivery.
Technology Capability	Reduce waste generated by manual consolidation of data for reporting purposes by delivering standard and custom Talent Management reporting.

Tibco API Exchange Gateway Replacement

Report Pulled: 4/14/2026 **Item ID: 11728**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Tibco API Exchange Gateway Replacement

Description This project is looking to retire the API Exchange Gateway within the Tibco ESB and replace it with a new solution called Microsoft Self-Hosted Gateway. The API Exchange Gateway is used by the TIBCO ESB to integrate to external vendors, all new development will need to be done to integrate this solution.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement The Tibco API Exchange Gateway is anticipated to be sunset by the vendor, as they have already dropped all development of enhancements for the platform.

Objectives This project creates value for the Company by: (1) Avoiding the risk of running a project no longer supported by the vendor (i.e. the Tibco Enterprise Service Bus API Exchange module), and (2) Enabling the Company the opportunity to move to a product that is more stable, secure, and usable.

Scope The project scope includes: (1) Conducting a RFP to procure a replacement product and work with architecture team to migrate the product. (2) Migrate all current work items to the new platform. (3) Conduct appropriate testing to ensure all Service Level Agreements are met.

Alternatives Alternatives considered include: (1) Evaluating the replacement of the current product with a new product that is not already in the Company environment. This alternative was not selected because it would not be cost effective. (2) Keeping the current application as-is. This alternative was not selected as the vendor for the current platform has stopped all development for this product. (3) Leveraging an existing solution already in the Company environment. This alternative was selected as it avoids multiple solutions with redundant capabilities and avoids costs for supporting and maintaining a second solution.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/15/2024	2/5/2024	3/5/2024	4/1/2024
	In-Service/Go-Live	**Closeout**	
	8/5/2024	12/13/2024	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.162	$0.015	-	-	-	-	-	-	$0.177
O&M	$0.110	$0.007	-	-	-	-	-	-	$0.117
Total Cost of Ownership	$0.272	$0.022	-	-	-	-	-	-	**$0.294**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.133	$0.015	-	-	-	-	-	-	**$0.148**
Outside Services	$0.139	$0.007	-	-	-	-	-	-	**$0.146**
Business Expense/Overheads	-	-	-	-	-	-	-	-	-
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.272	$0.022	-	-	-	-	-	-	**$0.294**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.110	$0.007	-	-	-	-	-	-	**$0.117**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.110	$0.007	-	-	-	-	-	-	**$0.117**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.162	$0.015	-	-	-	-	-	-	**$0.177**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.162	$0.015	-	-	-	-	-	-	**$0.177**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	TIBCO has announced that the API Exchange Gateway will no longer be developed and supported, so we are at risk of being reliant on software that is obsolete.

OTHER VALUE

Type	Description

Transmission Outage Application (TOA) Upgrade

Report Pulled: 4/20/2026 **Item ID:** 12481

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Transmission Outage Application (TOA) Upgrade

Description This project will modernize and streamline the high voltage system outage process, substation asset management, construction management and maintenance processes, as well as the high voltage project management process by replacing obsolete systems with an industry standard alternative and providing future integration opportunities with corporate systems.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The current software version is no longer supported by the vendor and does not allow for the enhancements that would increase the functionality of the software. Also, the solution is susceptible to human error and duplication of efforts due to the manual nature of the work. Lastly, the ongoing support of the software is also costly and time consuming due to the outdated version and the requirements for the existing solution.

Objectives The project will add value by: (1) simplifying the process of managing and rescheduling large HVD projects; (2) enhancing the ability to quickly identify conflicts created by schedule changes; (3) allowing the Company to internally support future integrations with existing applications; (4) improving resource management and visibility by planning Substation Construction, Substation Operations, and High Voltage Distribution (HVD) Lines resources by project; (5) implementing ability to plan Control Center resources based on planned work and control center capacity; (6) improving visibility and repeatable reporting for defects and problem solving; (7) simplifying communication with stakeholder groups including Low Voltage Distribution (LVD) Scheduling, Business Customer Solutions, Electric Field Lab, and Substation Operations for outage requests requiring resource coordination; and (8) including 24x7 application support and patching due to using a Cloud solution.

Scope The scope of the project includes: (1) upgrading to the newest version of software for a real-time electric operations application; (2) migration of applications and data to cloud servers; and (3) end-user testing.

Alternatives The alternatives considered for the project include: (1) continuing with the current system and processes. This alternative was not selected because the current version is out of support, is prone to human error and duplication, and is costly to maintain. (2) breaking the project into separate Company built applications. This alternative was not selected because these individual applications would have integration complications and support issues, as they would all be separate entities. (3) purchase an off-the-shelf cloud option. This alternative was selected as it would not have customization of the base product or integration issues and comes with 24x7 cloud support.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
6/2/2025	6/13/2025	6/27/2025	2/27/2026
	In-Service/Go-Live	**Closeout**	
	3/1/2026	3/17/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$0.349	$0.513	-	-	-	-	-	$0.862
O&M	-	$0.013	$0.264	$0.137	$0.143	$0.150	-	-	$0.707
Total Cost of Ownership	-	$0.362	$0.776	$0.137	$0.143	$0.150	-	-	**$1.569**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.012	$0.247	-	-	-	-	-	**$0.259**
Outside Services	-	$0.230	-	-	-	-	-	-	**$0.230**
Business Expense/Overheads	-	$0.004	$0.086	-	-	-	-	-	**$0.090**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.115	$0.444	-	-	-	-	-	**$0.559**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.362	$0.776	-	-	-	-	-	**$1.138**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	$(0.015)	$(0.015)	$(0.015)	$(0.015)	$(0.015)	-	-	-	**$(0.075)**
	Initial	-	$0.013	$0.264	$0.137	$0.143	$0.150	-	-	**$0.707**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$(0.015)	$(0.002)	$0.249	$0.122	$0.128	$0.150	-	-	**$0.632**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.349	$0.513	-	-	-	-	-	**$0.862**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.349	$0.513	-	-	-	-	-	**$0.862**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.955

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Automated Notification Module with Query Builder - Labor waste reduction for Scheduled Outage by eliminating manual emailing for specific types of resource coordination requests that will now be handled through automated notifications vs manual emails
Avoided Costs	Project Module - Reduction in deconfliction labor for Substation Operations, Substation Construction, and HVD Lines
Avoided Costs	Project Module - Reduction in Scheduled Outage labor due to simplified schedule management for large outage schedule changes.
Avoided Costs	Reporting Module with Query Builder - 1 hour weekly avoided labor for avoiding manual exports of TOA data to support visual management reporting via Power BI
Avoided Costs	Reporting Module with Query Builder - 1 hour weekly waste elimination for TOA owner to perform Daily Listing reporting and improved data accuracy and visibility
Avoided Costs	Resource Planning Module - Elimination of 1 hour of weekly waste for Scheduled Outage, System Control Center, and Distribution Control Center Superintendents for control center capacity management
Avoided Costs	Resource Planning Module - Improvement in field resource labor efficiency though reduction of stranded resources and allowing better balancing of resources across all existing work based on target completion dates
Avoided Costs	Sun-Net Cloud Hosting and Technical Annual Support - Update the iTOA software to the latest version to reduce recurring waste for software updates and bring software to a version that is supported by the vendor
Avoided Costs	System Protection Event Analysis Module / Interruption Outage Module: 5% reduction of logging by Lead System Control, System Control Center, and Distribution Control Center during storms and large events. Approximately 65 hours per year avoided.

Total Information Management (TIM) Platform Upgrade

Report Pulled: 4/13/2026 **Item ID:** 14013

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Open Text (TIM) SaaS Migration, Total Information Managment (TIM) Platform Upgrade, Total Information Management (TIM) Platform Upgrade

Description The project will replace the existing Total Information Management (TIM) on-premise solution with a cloud-based OpenText Software as a Service (SaaS) solution. It will provide the Company with the ability to reduce operational costs for performing upgrades and maintenance, take advantage of new enhancements offered by the vendor, and ensure continued support of the platform.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement The existing on-premise Total Information Management (TIM) solution hardware and software is at end of support. The state of the current infrastructure creates security, stability, and reliability risk for the platform. Without vendor support, the application no longer receives security patches, bug fixes, or functionality support from the vendor, which creates additional security, stability, and reliability risk.

Objectives This project will provide value to the Company through: (1) reducing costs with cloud allocated hardware scalable to current usage needs; (2) reducing operating costs with vendor managed feature updates and maintenance provided without service disruption; (3) providing access to new and innovative capabilities; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.

Scope The project scope includes: (1) migrating, upgrading, and transforming the dataset to the latest version of OpenText Extended Enterprise Content Management (xECM) Cloud Edition and deploying in the vendor hosted cloud; (2) migrating on-premise documents to the vendor hosted OpenText Core Archive cloud; and (3) enabling new functionality including a new user interface, new workflow capabilities, new workgroup management features, and new integrations with Microsoft 365 applications.

Alternatives Alternatives considered include: (1) Defer to a future date. This alternative was not selected due to requiring upgrades of existing on-premise hardware, impeding our ability to take advantage of new features offered by the cloud solution, and reducing cost savings opportunities presented by moving to the cloud. (2) Deploy OpenText on-premise solution to new on-premise hardware. This alternative was not selected due to cost associated with purchasing new hardware, cost associated to maintain, and it does not free up internal resources to focus on other value-added initiatives. (3) Select and migrate to a new vendor software. This alternative was not selected due to the cost, effort, and complexity of replacing the platform with a whole new technology. (4) Migrate to the OpenText cloud platform. This alternative was selected due to it building on the Company strategy of moving to cloud, reducing operating and maintenance costs, and it reduces risk by ensuring consistent, seamless vendor support.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/12/2025	3/17/2025	4/17/2025	6/30/2025
	In-Service/Go-Live	**Closeout**	
	7/31/2025	8/31/2025	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$2.755	-	-	-	-	-	-	-	$2.755
O&M	$0.513	-	-	-	-	-	-	-	$0.513
Total Cost of Ownership	$3.268	-	-	-	-	-	-	-	**$3.268**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.155	-	-	-	-	-	-	-	**$0.155**
Outside Services	$2.557	-	-	-	-	-	-	-	**$2.557**
Business Expense/Overheads	$0.144	-	-	-	-	-	-	-	**$0.144**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.411	-	-	-	-	-	-	-	**$0.411**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.268	-	-	-	-	-	-	-	**$3.268**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.513	-	-	-	-	-	-	-	**$0.513**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.513	-	-	-	-	-	-	-	**$0.513**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.755	-	-	-	-	-	-	-	**$2.755**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.755	-	-	-	-	-	-	-	**$2.755**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Migrating OpenText solution from on-premise to SaaS is projected to result in $220K of annual cost avoidance ($1.1M for 5 years) due to avoiding annual costs associated with application currency, software maintenance, upgrades, infrastructure maintenance, server patching, vulnerability testing, and cloud hosting services.
Intangibles	Migrating to a SaaS cloud managed service simplifies the company's IT environment, makes it easier and less costly to maintain, minimizes potential for downtime and disruptions, and frees up IT resources to focus less on maintaining the platform and allocate more time to delivering solutions within the platform or value through other initiatives.
Intangibles	New features will be available by upgrading from the Extended ECM plan to the X1 X-Plan SaaS solution which includes Microsoft 365 Integration, Electronic Signature, Controlled Viewing and Printing, XML Workflow Extensions, and will optimize user licensing and provide additional add-on opportunities.
Risk Mitigation	Risk will be mitigated using the SaaS solution by providing infrastructure scaling as needed, minimizing service disruption through vendor managed feature updates and maintenance, enabling access to new and innovative capabilities, and reducing security, stability, and performance risk by leveraging a vendor managed cloud-based SaaS solution. Mitigates Security Vulnerability: Oracle_JRE_VAPT-CVE-2022-34169. Our current version of TIM runs Tomcat v8, which is subject to this vulnerability. We need to upgrade our TIM environment to the latest vendor supported version, so that we can migrate to the version of Apache Tomcat (v9.0.x or later) that closes this vulnerability. All other JAVA vulnerabilities were closed with the migration to Azul.

Vulnerability and Exposure Management Program Enablement

Report Pulled: 4/13/2026 **Item ID:** 14033

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Vulnerability Management - Exposure Management, Vulnerability and Exposure Management Program Enablement

Description This project will enhance the Company's Vulnerability Management program by implementing a cohesive suite of technologies focused on Vulnerability Management. These technologies will include minimally the following capabilities: vulnerability management, web application static and dynamic analysis, and attack surface management. Vulnerability Management is a critical process for identifying, assessing, and mitigating security weaknesses within an organization's IT infrastructure. This proactive approach involves continuous monitoring and evaluation of systems to detect vulnerabilities that could be exploited by cyber threats. By prioritizing vulnerabilities based on risk, cost, and potential impact, organizations can effectively allocate resources to address the most critical issues first. Implementing a robust Vulnerability Management program not only enhances the security posture of the organization but also ensures compliance with industry regulations and standards, thereby reducing the risk of data breaches, malware infections, ransomware, and other cyber threats. This Vulnerability Management program supports business continuity and protects sensitive information and systems, making it an essential component of any comprehensive cybersecurity strategy.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STANDA

WORK OBJECTIVES

Problem Statement The Company's current Vulnerability Management program relies on multiple disparate tools to perform core activities such as scanning, analysis, and remediation tracking. This multi-tool approach can create inefficiencies, increase the likelihood of data gaps, and require additional effort from users to correlate and interpret information across platforms. The use of several systems to manage vulnerabilities can lead to inconsistent workflows, duplicated efforts, and reduced coordination between teams. Streamlining the tool set or improving integration between existing solutions would enhance operational efficiency and support a more cohesive vulnerability management process.

Objectives This project creates value for the Company by (1) enhancing the efficiency and effectiveness of the Vulnerability Management program through improved integration and reduced reliance on multiple standalone tools; and (2) supporting risk-based decision-making by enabling more consistent identification, prioritization, and remediation of vulnerabilities. These improvements will reduce operational overhead, minimize security exposure, and help ensure continued alignment with industry regulations and cybersecurity frameworks.

Scope The project scope includes evaluating and implementing a new vulnerability solution. The scope also includes enablement of active scanning with the new solution, consolidating data sources, and improving cross-platform visibility.

Alternatives Alternatives considered include: (1) continuing with the current multi-tool Vulnerability Management program. This option was not selected as it perpetuates inefficiencies, inconsistent workflows, and limited visibility across platforms; (2) increasing manual efforts to correlate and manage data between existing tools. This alternative was not chosen due to the high resource demands and increased risk of human error, which may further delay remediation timelines; (3) procurement of a new, cloud-based consolidated vulnerability management platform. This option was chosen as it allows the Company to enhance vulnerability data, threat intelligence, and process efficiencies within the current environment to deliver immediate value with high confidence in the vulnerability data that is being provided.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/15/2027	2/27/2027	3/27/2027	10/26/2027
	In-Service/Go-Live	**Closeout**	
	10/28/2027	11/27/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	$1.419	-	-	-	-	-	-	$1.419
O&M	-	$0.291	-	-	-	-	-	-	$0.291
Total Cost of Ownership	-	$1.710	-	-	-	-	-	-	**$1.710**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	-	$0.140	-	-	-	-	-	-	**$0.140**
Outside Services	-	$0.035	-	-	-	-	-	-	**$0.035**
Business Expense/Overheads	-	$0.380	-	-	-	-	-	-	**$0.380**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$1.155	-	-	-	-	-	-	**$1.155**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$1.710	-	-	-	-	-	-	**$1.710**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.291	-	-	-	-	-	-	**$0.291**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.291	-	-	-	-	-	-	**$0.291**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$1.419	-	-	-	-	-	-	**$1.419**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$1.419	-	-	-	-	-	-	**$1.419**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Work Management Scheduling Analytics and Reporting

Report Pulled: 4/13/2026 **Item ID:** 6811

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias DCO Scheduling Tool Project, DOET Scheduling Tool Project,Work Management Scheduling, Analytics, and Reporting, Work Management Scheduling Analytics and Reporting

Description The project will implement a solution to optimize the key components of the Distribution Planning and Scheduling functions including forecasting, work order intake, resource identification, work schedule creation, work execution preparation and associated work order analytics.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement The Distribution Planning, Scheduling and Administrative Support & Financial Services (Work Plan Strategy) teams are utilizing manually intensive work methods, systems and forecasting models. These inefficiencies impact the creation of work plans, lack predictive capacity planning, and reduce productivity of operational partners.

Objectives The project will add value by providing: (1) streamlined processes tied to workload review and preparatory analysis, leading to increased focus on workload priority, execution of work and a reduction of human struggle; (2)increased accuracy in crew work schedules, leading to improved customer satisfaction and on-time delivery of customer requested work, system integrity work, and gas compliance requirements; (3) reduced manual scheduling steps, reporting and analysis of data associated with work management processes and systems; thereby minimizing the risk of human error hours spent developing and updating crew route sheets; and (4) improved forecasting accuracy, that results in greater transparency into the weekly schedule and associated work plan.

Scope The project scope includes: (1) implement a solution to facilitate the review of work orders from various engineering organizations, allowing for streamlined check-in of work orders; (2) implement a scheduling tool that utilizes predictive modelling and advanced analytics and streamlines daily schedule modifications; (3) enhance integration with the Arcos application to bring in employee capacity and availability information; (4) integrate with SAP to retrieve work order data and manage record keeping requirements; (5) enhance integration with Field Service Suite (FSS) for quicker access to MISS DIG information and work order assignments; and (6) implement associated analytics and reporting.

Alternatives Three primary alternatives were considered for this project: (1) Automating manual data movement across excel and current systems through Robotic Process Automation. This option was not chosen because it will not meet base requirements and will not provide desired insights into whether the schedule supports operating priorities and metrics, financial scenarios, first time completion of work, and daily goals; (2) Integrating an off-the-shelf planning and scheduling system. This option is not preferred due to associated up-front and long-term costs; and (3) Implementing a hybrid of an off-the-shelf planning component with custom built scheduling functions. This is the preferred option to provide a more cost-effective and targeted fit for the organization.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/11/2022	4/16/2022	6/18/2022	1/28/2023
	In-Service/Go-Live	**Closeout**	
	10/9/2024	10/16/2024	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	$0.825	$0.952	$0.103	$0.052	-	-	-	-	$1.932
O&M	$0.071	$0.046	$0.047	$0.048	$0.075	$0.075	$0.075	-	$0.437
Total Cost of Ownership	$0.896	$0.998	$0.150	$0.100	$0.075	$0.075	$0.075	-	**$2.369**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	$0.122	$0.195	$0.038	$0.010	-	-	-	-	**$0.365**
Outside Services	$0.678	$0.630	$0.052	$0.004	-	-	-	-	**$1.365**
Business Expense/Overheads	$0.088	$0.141	$0.013	$0.010	-	-	-	-	**$0.251**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.000	$0.019	-	-	-	-	-	**$0.020**
Licenses, Permits & Fees	$0.009	$0.032	$0.027	$0.076	-	-	-	-	**$0.144**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.896	$0.998	$0.150	$0.100	-	-	-	-	**$2.144**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	$(0.045)	$(0.054)	$(0.054)	$(0.054)	$(0.054)	$(0.054)	-	**$(0.314)**
	Initial	$0.071	$0.046	$0.047	$0.048	$0.075	$0.075	$0.075	-	**$0.437**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.071	$0.001	$(0.007)	$(0.006)	$0.021	$0.021	$0.021	-	**$0.123**
Cap+COR	Reduction	-	$(0.159)	$(0.191)	$(0.191)	$(0.191)	$(0.191)	$(0.191)	-	**$(1.113)**
	Initial	$0.825	$0.952	$0.103	$0.052	-	-	-	-	**$1.932**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.825	$0.793	$(0.087)	$(0.139)	$(0.191)	$(0.191)	$(0.191)	-	**$0.819**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.500

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	As a result of improved forecasting accuracy, greater transparency into the weekly schedule and associated work plan would lead to improved on time completion of workplan elements relating to customer requested work and system improvement projects. It would also support problem solving in unit/hourly costs.
Intangibles	Employee engagement is improved by reducing human struggle, while being able to focus on priority and execution of work versus relying on workarounds and extra steps to meet daily scheduling needs.
Intangibles	Increased accuracy in crew work schedules, resulting in increased on-time completion of electric system integrity and gas compliance work. Based on the reduction of scheduling errors, a projected increase of 10% in the First Time Quality scheduling metric.
Intangibles	Increased accuracy of crew work schedules and First Time Quality are projected to lead to a 4% increase in Customer Satisfaction as measured by CXi
Avoided Costs	Initial savings based on implementation at one Company service center yielded $50,000 in savings from reduced truck rolls and reduced job delays through an enhanced quality control process . It is the intention of the Company to expand this statewide where further savings will be realized.

Workstation Temporary Administrative Access

Report Pulled: 4/15/2026 **Item ID:** 10497

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Workstation Temporary Administrative Access

Description This project will implement controls that will allow local least administrative access to workstations on a time limited basis. Non-IT and Security resources will be able to request this access. Temporary administrative access to workstations is required to support some application installations, local system configuration, or to troubleshoot workstation issues. Currently, administrative access is only allowed on employee workstations for authorized users that is granted by a manual process. The current process allows the authorized user to have access to everything on the employee workstation which allows for human error. The process is resource intensive and requires manual removal of access.

Portfolio Corporate Services > Security Services > Cyber Security & Shared Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAND/

WORK OBJECTIVES

Problem Statement Cyber Security and Information Technology (IT) teams do not have controls in place to restrict the usage of local administrative accounts or monitoring capabilities to detect misuse without human intervention. The current state creates an environment for misuse where broad admin access could be leveraged for data breaches and ransomware. A successful attack would impact the Company's ability to serve our customers.

Objectives This project creates value for the Company by: (1) reducing risk by eliminating over 1,000 local administrative accounts; (2) adding the ability to implement security controls and restrictions on local administrative functions; (3) increasing productivity by reducing the time and resources needed to provision, manage, and audit local accounts for security compliance; (4) adding the ability to provide administrative access for a specific and limited duration of time, thereby reducing cyber security risk of workstation compromise.

Scope This project will implement a platform that can enforce security controls and audit the security compliance of local administrative accounts for Company workstations. The features of this platform include: (1) the ability to give administrator access for a specific duration of time; (2) enable applications to automatically run in a privileged state; (3) the ability to remotely change the administrator password; and (4) generate a single-use administrator password.

Alternatives Alternatives considered include: (1) accepting the risk of using local accounts that are not managed centrally for end point administration. This alternative was not chosen because the usage of these accounts doesn't follow company standards for software provisioning and introduces unsupported software versions and vulnerabilities into the environment; (2) continuing the existing practice of manual oversight to grant local administrative access which does not eliminate the risk of misuse of administrator access. This alternative was not selected because it doesn't follow company standards for software provisioning and introduces unsupported software versions and vulnerabilities into the environment; (3) developing a platform for administrative account access internally. This alternative was not chosen due to the time frame it would take internal resources to develop and maintain the solution at the same level of quality and feature parity as a commercial product; and (4) implement a cloud platform specifically developed for managing local administrative accounts. This option was chosen because of the features designed for managing local administrative accounts will reduce the risk of misuse of administrative credentials within the Company.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
2/1/2027	3/2/2027	4/3/2027	6/25/2027
	In-Service/Go-Live	**Closeout**	
	6/26/2027	7/30/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	$0.995	-	-	-	-	-	-	$0.995
O&M	-	$0.190	-	-	-	-	-	-	$0.190
Total Cost of Ownership	-	$1.185	-	-	-	-	-	-	**$1.185**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	-	$0.083	-	-	-	-	-	-	**$0.083**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	$0.353	-	-	-	-	-	-	**$0.353**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.750	-	-	-	-	-	-	**$0.750**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$1.185	-	-	-	-	-	-	**$1.185**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.190	-	-	-	-	-	-	**$0.190**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.190	-	-	-	-	-	-	**$0.190**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.995	-	-	-	-	-	-	**$0.995**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.995	-	-	-	-	-	-	**$0.995**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Add the ability to implement security controls and restrictions on local administrative functions.
Technology Capability	Add the ability to provide administrative access for a specific and limited duration of time, thereby reducing cyber security risk of workstation compromise.
Technology Capability	Increase productivity by reducing the time and resources needed to provision, manage, and audit local accounts for security compliance.
Technology Capability	Reduce risk by eliminating over 1,000 local administrative accounts.

EXHIBIT A-23 (SHB-8)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Electric and Common Capital Expenditures
For the Projected Year 2026, 2027, and Test Year Ending April 30, 2028
For the Historical Year 2025

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ARP-Collaboration

Line No.	(a) Units	(b) Avg. Unit Cost	(c) Total 2027 Units	(d) Total 2028 Units	(e) Total 2027 Dollars	(f) Total 2028 Dollars	(g) Total Test Year Dollars	(h) Test Year Electric Allocation Dollars
1	ClickShare Refresh	$2,807	2	0	$5,614	$0	$3,743	$2,479
2	ClickShare Refresh	$2,807	0	2	$0	$5,614	$1,871	$1,240
3	Conference room refresh/modernize - Auditorium	$144,738	1	0	$144,738	$0	$96,492	$63,916
4	Conference room refresh/modernize - Auditorium	$159,000	0	1	$0	$159,000	$53,000	$35,107
5	Conference room refresh/modernize - Medium	$5,490	5	0	$27,450	$0	$18,300	$12,122
6	Conference room refresh/modernize - Medium	$5,490	0	5	$0	$27,450	$9,150	$6,061
7	Conference room refresh/modernize - Large	$28,879	1	0	$28,879	$0	$19,253	$12,753
8	Conference room refresh/modernize - Large	$53,000	0	1	$0	$53,000	$17,667	$11,702
9	LCD Displays	$1,279	16	0	$20,464	$0	$13,643	$9,037
10	LCD Displays	$1,279	0	17	$0	$21,743	$7,248	$4,801
11	Microsoft Teams Room Refresh (MTR) - 65" bundled	$5,558	0	25	$0	$138,950	$46,317	$30,680
12	Microsoft Teams Room Refresh (MTR) -75" bundled	$6,319	0	24	$0	$151,656	$50,552	$33,486
13	Oracle (SBC) Session Border Controls	$30,541	4	0	$122,164	$0	$81,443	$53,948
14	Projectors - bundled	$6,658	2	0	$13,316	$0	$8,877	$5,880
15	Projectors - bundled	$6,658	0	2	$0	$13,316	$4,439	$2,940
16	Surface Hub Refresh 50"	$10,002	0	33	$0	$330,066	$110,022	$72,879
17	Surface Hub Refresh 85"	$24,693	0	57	$0	$1,407,501	$469,167	$310,776
18	Accessories				$65,000	$100,000	$76,667	$50,784
19	Electric				$302,648	$231,023	$278,773	$184,659
20	**Total Electric Allocation**				$730,273	$2,639,319	**$1,366,622**	**$905,250**

	Units	Avg. Unit Cost	Total 2025 Units	Total 2026 Units	Total 2025 Dollars	Total 2026 Dollars	2025 Electric Allocation Dollars	2026 Gas Allocation Dollars
21	Cisco Analog Gateway - 24 port	$5,353	2	0	$10,706	$0	$7,341	$0
22	Cisco Analog Gateway - 48 port	$10,680	2	0	$21,360	$0	$14,647	$0
23	ClickShare Refresh	$2,288	11	0	$25,168	$0	$17,258	$0
24	Conference room refresh/modernize - Auditorium	$5,920	12	0	$71,040	$0	$48,712	$0
25	Conference room refresh/modernize - Auditorium	$141,483	0	2	$0	$282,966	$0	$187,437
26	Conference room refresh/modernize - Large	$28,230	0	2	$0	$56,460	$0	$37,399
27	Conference room refresh/modernize - Medium	$15,000	0	0	$0	$0	$0	$0
28	Conference room refresh/modernize - Small	$7,830	37	0	$289,710	$0	$198,654	$0
29	LCD Displays	$1,572	8	0	$12,576	$0	$8,623	$0
30	LCD Displays	$1,054	0	16	$0	$16,864	$0	$11,171
31	New Teams Rooms	$10,000	0	11	$0	$110,000	$0	$72,864
32	Oracle (SBC) Session Border Controls	$28,896	4	0	$115,584	$0	$79,256	$0
33	Projectors - bundled	$3,300	2	0	$6,600	$0	$4,526	$0
34	Standalon Hub Mics (2 per room)	$1,282	38	0	$48,716	$0	$33,405	$0
35	Standalon Hub Mics (2 per room)	$2,800	0	33	$0	$92,400	$0	$61,206
36	Surface Hub 85" Gen 1 replacement	$24,481	3	0	$73,443	$0	$50,360	$0
37	Surface Hub Refresh 50"	$13,340	0	0	$0	$0	$0	$0
38	Surface Hub Refresh 85"	$24,481	1	0	$24,481	$0	$16,787	$0
39	Surface Hub Refresh 85"	$28,140	0	0	$0	$0	$0	$0
40	Surface Hubs Gen 1 replacement 50"	$9,790	2	0	$19,580	$0	$13,426	$0
41	Verint Servers/Software	$418,260	0	1	$0	$418,260	$0	$277,055
42	Accessories				$22,816	$71,296	$15,645	$47,226
43	Software, labor, contractor and overhead and other costs				$180,991	$114,626	$124,106	$75,928
44	**Total Electric Allocation**				$922,771	$1,162,872	**$632,744**	**$770,287**

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ARP-Cyber-Common

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Cisco Fiber SFP Modules	$600	0	96	$0	$57,600	$19,200	$10,057
2	Cisco Fiber SFP Modules	$25	48	0	$1,200	$0	$800	$419
3	Cisco FPR 4110 to FTD-3110	$24,000	0	12	$0	$288,000	$96,000	$50,285
4	Cisco FTD-2110 to FTD-3105	$16,000	6	0	$96,000	$0	$64,000	$33,523
5	Cisco ISE Model number SNS-3695-K9 to SNS-3795-K9	$90,000	2	0	$180,000	$0	$120,000	$62,856
6	F5 BIG-IP i2800 to F5-BIG-DNS-r2800	$40,000	2	0	$80,000	$0	$53,333	$27,936
7	Palo Alto Firewall PA-3120 Replacement PA-3400	$35,000	0	10	$0	$350,000	$116,667	$61,110
8	Palo Alto Firewall PA-5260 Replacement PA-5410	$62,000	16	0	$992,000	$0	$661,333	$346,406
9	Software, labor, contractor and overhead and other costs				$103,918	$53,624	$87,153	$45,651
10	**Total Electric Allocation**				$1,453,118	$749,224	**$1,218,486**	**$638,243**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
11	Cisco ASA 5516-X to FPR-1120	$3,000	0	4	$0	$12,000	$0	$6,286
12	Cisco ASA 5545-X to FPR-1140	$4,000	0	28	$0	$112,000	$0	$58,666
13	Cisco ASA 5555-X to FPR-1150	$8,000	0	4	$0	$32,000	$0	$16,762
14	F5 BIG-IP i2800 to F5-BIG-DNS-r2800	$40,000	0	2	$0	$80,000	$0	$41,904
15	F5 BIG-IP i4600 to F5-BIG-DNS-r4600	$50,000	0	2	$0	$100,000	$0	$52,380
16	F5 BIG-IP i4800 to F5-BIG-DNS-r4800	$60,000	0	1	$0	$60,000	$0	$31,428
17	F5 BIG-IP i5800 to F5-BIG-DNS-r5800	$101,000	0	7	$0	$707,000	$0	$370,327
18	Palo Alto Firewall PA-3120 Replacement PA-3400	$35,000	0	7	$0	$245,000	$0	$128,331
19	Palo Alto Firewall PA-5260 Replacement PA-5410	$62,000	0	4	$0	$248,000	$0	$129,902
20	Palo Alto Firewalls 820 Replacement PA-455	$4,607	14	0	$64,503	$0	$33,393	$0
21	Qradar Core Appliance	$218,530	1	0	$218,530	$0	$113,133	$0
22	Materials inadvertently accrued twice in December 2025, corrected in January 2026				$17,889	$0	$9,261	$0
23	Software, labor, contractor and overhead and other costs				$198,063	$123,036	$102,537	$64,446
24	**Total Electric Allocation**				$498,985	$1,719,036	**$258,324**	**$900,431**

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ARP-Cyber-Electric

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Cisco Fiber SFP Modules	$25	208	0	$5,200	$0	$3,467	$3,467
2	Cisco FTD-2110 to FTD-3105	$16,000	26	0	$416,000	$0	$277,333	$277,333
3	Palo Alto Firewalls 820 Replacement PA-455	$9,500	0	35	$0	$332,500	$110,833	$110,833
4	Software, labor, contractor and overhead and other costs				$49,580	$39,993	$46,384	$46,384
5	**Total Electric Allocation**				$470,780	$372,493	**$438,018**	**$438,018**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
6	Palo Alto Firewalls 3120 Replacement PA-3400	$35,000	0	7	$0	$245,000	$0	$245,000
7	Palo Alto Firewalls 820 Replacement PA-455	$4,529	11	0	$49,820	$0	$49,820	$0
8	Palo Alto Firewalls 820 Replacement PA-455	$9,500	0	13	$0	$123,500	$0	$123,500
9	Software, labor, contractor and overhead and other costs				$196	$44,147	$196	$44,147
10	**Total Electric Allocation**				$50,016	$412,647	**$50,016**	**$412,647**

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ARP-Field Device Asset Mgmt

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
	Replacements							
1	Field Devices CF33 w/acces	$4,883	922	727	$4,502,181	$3,549,984	$4,184,782	$2,772,000
2	Field Devices CF55 w/acces	$4,003	50	101	$200,163	$404,329	$268,218	$177,668
	New Purchases							
3	3-Year Historical Average				$689,177	$689,177	$689,177	$456,511
4	Software, labor, contractor and overhead and other costs				$142,884	$121,716	$135,828	$89,972
5	**Total Electric Allocation**				$5,534,405	$4,765,207	**$5,278,005**	**$3,496,151**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
	Replacements							
6	Field Devices CF33 w/acces	$3,860	279	0	$1,076,940	$0	$738,458	$0
7	Field Devices CF55 w/acces	$3,166	253	0	$800,998	$0	$549,244	$0
8	Field Devices CF33 w/acces	$4,883	0	1289	$0	$6,294,264	$0	$4,169,320
9	Field Devices CF55 w/acces	$4,003	0	49	$0	$196,160	$0	$129,936
10	CF33 accessories				$93,088	$0	$63,830	$0
	New Purchases							
11	3-Year Historical Average				$0	$891,952	$0	$590,829
12	Field Devices CF33	$3,860	79	0	$304,940	$0	$209,097	$0
13	Field Devices FZ55	$3,166	11	0	$34,826	$0	$23,880	$0
14	Accessories				$56,784	$0	$38,937	$0
15	Software, labor, contractor and overhead and other costs				$33,165	$196,686	$22,742	$130,285
16	**Total Electric Allocation**				$2,400,741	$7,579,062	**$1,646,188**	**$5,020,370**

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ARP-Infoblox

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
1	TCPWave IPAM Virtual Appliance	$34,914	2	0	$69,828	$0	$36,150	$0
2	TCPWave Remote Virtual Appliances (DNS/DHCP/Cloud)	$17,455	11	0	$192,004	$0	$99,400	$0
3	TCPWave TV450 IPAM Hardware Appliance	$45,888	1	0	$45,888	$0	$23,756	$0
4	TCPWave TV450 Remote Hardware Appliance	$39,902	2	0	$79,804	$0	$41,314	$0
5	Shipping	$226	1	0	$226	$0	$117	$0
6	Software, labor, contractor and overhead and other costs				$5,538	$0	$2,867	$0
7	**Total Electric Allocation**				$393,288	$0	**$203,605**	**$0**

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ARP-Network-Common

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	C9800-40-K9 - Wireless Controllers	$20,854	0	6	$0	$125,126	$41,709	$21,847
2	C9800-L-F-K9	$4,850	0	4	$0	$19,399	$6,466	$3,387
3	Cisco 8500	$34,129	7	0	$238,903	$0	$159,269	$83,425
4	Cisco 8500	$34,129	0	3	$0	$102,387	$34,129	$17,877
5	Cisco APIC-CLUSTER-M3	$22,780	9	0	$205,020	$0	$136,680	$71,593
6	Cisco ISR4461	$15,000	0	2	$0	$30,000	$10,000	$5,238
7	Cisco N9K-C93108-FX-B24C	$20,974	0	8	$0	$167,790	$55,930	$29,296
8	Cisco N9K-C9332C	$12,630	0	2	$0	$25,259	$8,420	$4,410
9	Cisco N9K-C9364C	$20,932	4	0	$83,729	$0	$55,819	$29,238
10	Cisco SE-CL-L3	$58,194	4	0	$232,775	$0	$155,183	$81,285
11	Datacom Line Tap	$3,887	5	0	$19,435	$0	$12,957	$6,787
12	Datacom Line Tap	$3,887	0	5	$0	$19,435	$6,478	$3,393
13	DN-SW-APL	$17,701	0	1	$0	$17,701	$5,900	$3,091
14	Hirschmann BRS-32 Field Switch 942170999-21510232575	$3,939	10	0	$39,390	$0	$26,260	$13,755
15	Hirschmann Fiber Optic	$198	10	0	$1,980	$0	$1,320	$691
16	Hirschmann GRS1042-6T6ZEHH00VYHHSE2A99XX	$13,207	0	2	$0	$26,414	$8,805	$4,612
17	Hirschmann RJ45 SFP	$447	10	0	$4,470	$0	$2,980	$1,561
18	Juniper EX4600-40F	$8,865	28	0	$248,220	$0	$165,480	$86,678
19	Juniper EX4600-40F	$8,865	0	17	$0	$150,705	$50,235	$26,313
20	Juniper EX4650-48Y	$12,625	22	0	$277,750	$0	$185,167	$96,990
21	Juniper QFX5120-48T	$12,376	5	0	$61,880	$0	$41,253	$21,608
22	Juniper QFX5120-48T	$12,376	0	5	$0	$61,880	$20,627	$10,804
23	Software, labor, contractor and overhead and other costs				$101,641	$51,396	$84,893	$44,467
24	**Total Electric Allocation**				$1,515,192	$797,493	**$1,275,959**	**$668,347**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
25	Catalyst Wireless Access Points	$1,010	23	0	$23,233	$0	$12,027	$0
26	Datacom Line Tap	$3,887	0	5	$0	$19,435	$0	$10,180
27	Juniper EX4100-48MP	$3,396	0	6	$0	$20,378	$0	$10,674
28	Juniper EX4600-40F	$8,865	0	25	$0	$221,625	$0	$116,087
29	Juniper EX4650-48Y	$12,625	0	35	$0	$441,875	$0	$231,454
30	Juniper QFX5120-48T	$12,376	0	5	$0	$61,880	$0	$32,413
31	Software, labor, contractor and overhead and other costs				$18,220	$68,475	$9,432	$35,867
32	**Total Electric Allocation**				$41,452	$833,668	**$21,460**	**$436,676**

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ARP-Network-Electric

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Datacom Line Tap	$3,887	5	5	$19,435	$19,435	$19,435	$19,435
2	Hirschmann BRS-32 Field Switch 942170999-21510232575	$3,939	0	2	$0	$7,878	$2,626	$2,626
3	Hirschmann Fiber Optic	$198	0	50	$0	$9,900	$3,300	$3,300
4	Hirschmann GRS1042-6T6ZEHH00VYHHSE2A99XX	$13,207	0	3	$0	$39,621	$13,207	$13,207
5	Hirschmann RJ45 SFP	$447	0	50	$0	$22,350	$7,450	$7,450
6	Software, labor, contractor and overhead and other costs				$2,721	$6,933	$4,125	$4,125
7	**Total Electric Allocation**				$22,156	$106,117	**$50,143**	**$50,143**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
8	Cisco C8500	$64,944	5	0	$324,720	$0	$324,720	$0
9	Datacom Line Tap	$3,887	0	15	$0	$58,305	$0	$58,305
10	Software, labor, contractor and overhead and other costs				$127,510	$8,063	$127,510	$8,063
11	**Total Electric Allocation**				$452,230	$66,368	**$452,230**	**$66,368**

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ARP-OT Support-Common

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Test Year Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Servers Physical	$16,000	2	0	$32,000	$0	$21,333	$14,131
2	Servers Hyperconverged (Datacenter)	$125,000	11	20	$1,375,000	$2,500,000	$1,750,000	$1,159,200
3	Software, labor, contractor and overhead and other costs				$64,974	$99,960	$76,636	$50,764
4	**Total Electric Allocation**				$1,471,974	$2,599,960	**$1,847,969**	**$1,224,095**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
5	Servers Hyperconverged (Datacenter)	$61,483	12	0	$737,793	$0	$505,905	$0
6	Servers Hyperconverged (Field)	$21,093	3	0	$63,279	$0	$43,391	$0
7	Servers Hyperconverged (Datacenter)	$125,000	0	12	$0	$1,500,000	$0	$993,600
8	Software, labor, contractor and overhead and other costs				$968,055	$155,506	$663,796	$103,007
9	**Total Electric Allocation**				$1,769,128	$1,655,506	**$1,213,091**	**$1,096,607**

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ARP-OT Support-Electric

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Hardware Appliances	$35,000	4	0	$140,000	$0	$93,333	$93,333
2	Hyperconverged Cluster (Data Center)	$125,000	9	0	$1,125,000	$0	$750,000	$750,000
3	Hyperconverged Cluster (Field)	$55,000	7	0	$385,000	$0	$256,667	$256,667
4	Physical Servers	$16,000	4	14	$64,000	$224,000	$117,333	$117,333
5	Software, labor, contractor and overhead and other costs				$119,952	$69,972	$103,292	$103,292
6	**Total Electric Allocation**				$1,833,952	$293,972	**$1,320,625**	**$1,320,625**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
7	Hyperconverged Cluster (Field)	$13,074	3	0	$39,223	$0	$39,223	$0
8	Hyperconverged Cluster (Field)	$55,000	0	3	$0	$165,000	$0	$165,000
9	Software, labor, contractor and overhead and other costs				$174,217	$25,856	$174,217	$25,856
10	**Total Electric Allocation**				$213,440	$190,856	**$213,440**	**$190,856**

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ARP-Physical Security

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Dollars**	**Total Test Year**	**Test Year Electric Allocation Dollars**
1	Cabling/Misc Equipment	$10,000	13	13	$130,000	$130,000	$130,000	$86,112
2	Cameras	$3,575	160	160	$572,000	$572,000	$572,000	$378,893
3	Lift Charge	$5,000	13	13	$65,000	$65,000	$65,000	$43,056
4	Logistics & Operation Expense	$4,000	13	13	$52,000	$52,000	$52,000	$34,445
5	NVR/Monitor	$37,000	13	13	$481,000	$481,000	$481,000	$318,614
6	Software, labor, contractor and overhead and other costs				$814,320	$814,320	$814,320	$539,406
7	**Total Electric Allocation**				$2,114,320	$2,114,320	**$2,114,320**	**$1,400,526**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
8	3rd Party Vendor	$47,089	4	0	$188,356	$0	$129,155	$0
9	Cabling/Misc Equipment	$10,233	14	0	$143,261	$0	$98,234	$0
10	Cabling/Misc Equipment	$10,000	0	13	$0	$130,000	$0	$86,112
11	Cameras	$3,094	270	0	$835,272	$0	$572,746	$0
12	Cameras	$3,500	0	163	$0	$570,500	$0	$377,899
13	Card Access (SIO & SCP)	$618	6	0	$3,709	$0	$2,543	$0
14	Intercom	$1,531	10	0	$15,310	$0	$10,498	$0
15	Lift Charge	$4,295	12	0	$51,540	$0	$35,341	$0
16	Lift Charge	$5,000	0	13	$0	$65,000	$0	$43,056
17	Logistics & Operation Expense	$6,500	5	0	$32,499	$0	$22,285	$0
18	Logistics & Operation Expense	$4,000	0	13	$0	$52,000	$0	$34,445
19	NVR/Monitor	$35,726	14	0	$500,164	$0	$342,962	$0
20	NVR/Monitor	$37,000	0	13	$0	$481,000	$0	$318,614
21	Software, labor, contractor and overhead and other costs				$540,224	$814,320	$370,432	$539,406
22	**Total Electric Allocation**				$2,310,334	$2,112,820	**$1,584,196**	**$1,399,532**

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ARP-Printer Asset Management

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Test Year Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	IM C300	$1,974	9	0	$17,766	$0	$11,844	$7,845
2	IM C2500	$5,263	5	2	$26,315	$10,526	$21,052	$13,945
3	IM C3010	$5,743	54	27	$310,122	$155,061	$258,435	$171,187
4	IM C3510	$6,344	11	1	$69,784	$6,344	$48,637	$32,217
5	IM C6010	$7,450	12	2	$89,400	$14,900	$64,567	$42,769
6	MPC W2201	$8,204	14	5	$114,862	$41,022	$90,248	$59,781
7	SPC 8200	$6,807	1	0	$6,807	$0	$4,538	$3,006
8	IM C8000	$15,744	1	0	$15,744	$0	$10,496	$6,953
9	MP W6700 Plotter	$8,028	1	0	$8,028	$0	$5,352	$3,545
10	Accessories				$599	$0	$399	$265
11	Software, labor, contractor and overhead and other costs				$16,023	$5,439	$12,495	$8,277
12	**Total Electric Allocation**				$675,450	$233,292	**$528,064**	**$349,790**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
13	Fax Board	$1,158	1	0	$1,158	$0	$794	$0
14	IM C2500	$5,263	24	0	$126,312	$0	$86,612	$0
15	IM C2500	$5,263	0	5	$0	$26,315	$0	$17,431
16	IM C300	$1,974	84	6	$165,816	$11,844	$113,700	$7,845
17	IM C3010	$5,743	114	0	$654,702	$0	$448,929	$0
18	IM C3010	$5,743	0	6	$0	$34,458	$0	$22,825
19	IM C3510	$6,344	23	0	$145,912	$0	$100,052	$0
20	IM C6010	$7,450	3	0	$22,350	$0	$15,325	$0
21	IM C6010	$7,450	0	2	$0	$14,900	$0	$9,870
22	MPC W2201	$8,204	42	0	$344,568	$0	$236,270	$0
23	MPC W2201	$8,204	0	7	$0	$57,431	$0	$38,042
24	Ricoh PRO C5300 Flint	$34,426	0	1	$0	$34,426	$0	$22,804
25	Accessories				$361	$569	$248	$377
26	Software, labor, contractor and overhead and other costs				$98,848	$4,851	$67,780	$3,213
27	**Total Electric Allocation**				$1,560,027	$184,794	**$1,069,711**	**$122,408**

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ARP-Radio

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	800 Mhz mobile radios	$2,500	450	450	$1,125,000	$1,125,000	$1,125,000	$589,275
2	Bi-directional Amplifier (Large -Commercial) bundle	$1,411	8	0	$11,287	$0	$7,525	$3,941
3	Bi-directional Amplifier (Large -Commercial) bundle	$8,767	0	2	$0	$17,535	$5,845	$3,062
4	Cellular Modems	$1,920	20	0	$38,400	$0	$25,600	$13,409
5	Conventional Mobile Radios (high end subscriber)	$1,052	0	46	$0	$48,392	$16,131	$8,449
6	Havis Boxes (hardware)	$2,256	150	150	$338,456	$338,456	$338,456	$177,283
7	Tower Site Lighting Alarm Boxes Refresh	$2,500	5	0	$12,500	$0	$8,333	$4,365
8	Accessories				$112,500	$112,500	$112,500	$58,928
9	Software, labor, contractor and overhead and other costs				$100,592	$93,231	$98,138	$51,405
10	**Total Electric Allocation**				$1,738,734	$1,735,113	**$1,737,527**	**$910,117**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
11	800 Mhz mobile radios	$1,907	450	0	$858,150	$0	$444,264	$0
12	800 Mhz mobile radios	$2,114	0	450	$0	$951,377	$0	$498,331
13	800 Mhz portable radios	$1,670	40	0	$66,780	$0	$34,572	$0
14	Bi-directional Amplifier (Large -Commercial) bundle	$5,761	8	0	$46,088	$0	$23,860	$0
15	Bi-directional Amplifier (Large -Commercial) bundle	$1,411	0	8	$0	$11,287	$0	$5,912
16	Bi-directional Amplifier Hardware (Small System) - bundle	$1,396	12	0	$16,752	$0	$8,673	$0
17	Cellular Modems	$1,920	0	20	$0	$38,400	$0	$20,114
18	Conventional base station repeaters hardware	$9,943	0	2	$0	$19,886	$0	$10,416
19	Havis Boxes - 18"	$2,063	30	0	$61,875	$0	$32,033	$0
20	Havis Boxes - hump mount	$966	63	0	$60,837	$0	$31,495	$0
21	Havis Boxes (hardware)	$2,256	0	150	$0	$338,456	$0	$177,283
22	Accessories				$487,933	$0	$252,603	$0
23	Software, labor, contractor and overhead and other costs				($98,975)	$97,633	($51,239)	$51,140
24	**Total Electric Allocation**				$1,499,440	$1,457,038	**$776,260**	**$763,197**

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ARP-Server and Storage

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Nutanix xc640	$137,109	0	7	$0	$959,765	$319,922	$211,916
2	Labor, contractor and overhead and other costs				$0	$215,190	$71,730	$47,514
3	**Total Electric Allocation**				$0	$1,174,955	**$391,652**	**$259,430**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
4	NetApp Expansion	$62,629	2	0	$125,258	$0	$85,889	$0
5	Labor, contractor and overhead and other costs				$220,239	$0	$151,018	$0
6	**Total Electric Allocation**				$345,497	$0	**$236,907**	**$0**

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ARP-Workstation Asset Mgmt

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2027 Units**	**Total 2028 Units**	**Total 2027 Dollars**	**Total 2028 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
	Replacements							
1	16" Laptop	$3,037	191	832	$580,048	$2,526,701	$1,228,932	$814,045
2	Desktops	$1,378	480	256	$661,440	$352,768	$558,549	$369,983
3	HP Desktop Bundled	$3,835	73	142	$279,961	$544,581	$368,168	$243,874
4	Laptop	$1,908	1406	1828	$2,682,648	$3,487,824	$2,951,040	$1,954,769
5	Monitors 24"	$233	2159	3100	$503,479	$722,920	$576,626	$381,957
6	RT Mount Device	$8,692	0	55	$0	$478,060	$159,353	$105,556
7	Tablets	$2,644	9	42	$23,799	$111,063	$52,887	$35,032
8	Teams Monitors	$323	2159	3100	$698,005	$1,002,230	$799,413	$529,531
9	Accessories				$211,395	$375,050	$265,946	$176,163
	New Purchases							
10	New Purchases (3 YR Hist Avg)				$1,082,998	$1,082,998	$1,082,998	$717,378
11	Software, labor, contractor and overhead and other costs				$274,193	$400,685	$316,357	$209,555
12	**Total Electric Allocation**				$6,997,965	$11,084,879	**$8,360,270**	**$5,537,843**

	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**2025 Electric Allocation Dollars**	**2026 Electric Allocation Dollars**
	Replacements							
13	16" Laptop	$3,037	0	252	$0	$765,299	$0	$506,934
14	Desktops	$1,378	65	93	$89,570	$128,154	$61,418	$84,889
15	HP Desktop Bundled	$3,835	50	40	$191,750	$153,400	$131,483	$101,612
16	HP Desktops OT	$5,077	32	0	$162,464	$0	$111,402	$0
17	HP Laptop bundled	$3,021	518	0	$1,564,878	$0	$1,073,037	$0
18	Laptop	$1,625	2062	0	$3,351,142	$0	$2,297,878	$0
19	Laptop	$1,908	0	1500	$0	$2,862,000	$0	$1,895,789
20	Macs	$2,396	35	0	$83,860	$0	$57,503	$0
21	Monitors 24"	$271	50	0	$13,550	$0	$9,291	$0
22	RT Mount Device	$8,692	0	14	$0	$121,688	$0	$80,606
23	SFF Desktop	$1,385	4	0	$5,540	$0	$3,799	$0
24	Surface Pro Laptops	$1,887	3	0	$5,661	$0	$3,882	$0
25	Tablets	$1,935	35	0	$67,725	$0	$46,439	$0
26	Teams Monitors	$312	354	0	$110,448	$0	$75,734	$0
27	Accessories				$368,606	$232,341	$252,753	$153,903
	New Purchases							
28	24" Monitors	$271	300	0	$81,300	$0	$55,747	$0
29	HP laptop (16")	$3,021	225	0	$679,725	$0	$466,087	$0
30	Laptop (14")	$1,625	343	0	$557,440	$0	$382,237	$0
31	SFF Desktop	$1,385	12	0	$16,621	$0	$11,397	$0
32	Surface Pro Tablets	$1,935	12	0	$23,220	$0	$15,922	$0
33	Teams Monitors	$312	592	0	$184,704	$0	$126,652	$0
34	New Purchases (3 YR Hist Avg)				$0	$1,000,000	$0	$662,400
35	Accessories				$101,378	$0	$69,515	$0
36	Software, labor, contractor and overhead and other costs				$384,651	$279,273	$263,755	$184,990
37	**Total Electric Allocation**				$8,044,233	$5,542,155	**$5,515,931**	**$3,671,123**

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New Purchases Historical Acutal 2022 - 2025

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Line No.	(a) Year	(b) Total Company New Purchases	(c) Reference*
1	2022	$ 778,339	Electric: U-21389, Exhibit No. A-182 (HNW-8), page 8, column e, lines 64 and 66 plus 35% of lines 72 - 73 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees. Gas: U-21490, Exhibit No. A-22 (SHB-7), page 9, column e, lines 55 and 57 plus 35% of lines 72 - 73 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
2	2023	$ 880,134	Electric: U-21585, Exhibit No. A-90 (SK-8), page 9, column e, lines 52-54 plus 73% of lines 59 - 60 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees. Gas: U-21806, Exhibit No. A-22 (SHB-7), page 12, column e, lines 52 - 54 plush 73% of line 59 - 60 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
3	2024	$ 701,684	Electric: U-21870, Exhibit No. A-22 (SHB-7), page 5, column e, lines 12, 14, 16, and 18. Gas: U-21981, Exhibit No. A-24 (SHB-9), page 5, column e, lines 13, 15, 17, and 18.
4	2025	$ 396,550	Electric: U-22070, Exhibit No. A-24 (SHB-9), page 4, column e, lines 12 - 14.
5	Total Company Four-year Historical Average 2022 - 2025	$ 689,177	Used to project 2027 and 2028 costs
6	Electric Allocation Four-year Historical Average 2022 - 2025	$ 456,511	Used to project 2027 and 2028 costs

*Note: In 2021, 2022, and 2023 Field Device new purchases were a part of ARP-Workstation Asset Management and not ARP-FDAM.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Program-Field Device Asset Management
New Purchases Historical Acutal 2022 - 2025

Case No.: U-22070
Exhibit No.: A-25 (SHB-10)
Page: 2 of 2
Witness: SHBaker
Date: June 2026

Line No.	(a) Year	(b) Total Company New Purchases	(c) Reference*
1	2022	$ 1,414,635	Electric: U-21389, Exhibit No. A-182 (HNW-8), page 8, column e, lines 48, 50, 52, 54, 56, 59, 62, 68, 70, 72, and 73 plus 65% of lines 72 - 73 for ARP-WAM new purchases portion of accessories, shipping and handling, and other fees. Gas: U-21490, Exhibit No. A-22 (SHB-7), page 9, column e, lines 44, 46 - 47, 49 - 51, 53, and 58 - 59 plus 65% of lines 60 - 61 for ARP-WAM new purchases portion of accessories, shipping and handling, and other fees.
2	2023	$ 318,694	Electric: U-21870, Exhibit No. A-22 (SHB-7), page 5, column e, lines 12, 14, 16, and 18. Gas: U-21981, Exhibit No. A-24 (SHB-9), page 5, column e, lines 13, 15, 17, and 18.
3	2024	$ 954,274	Electric: U-21870, Exhibit No. A-22 (SHB-7), page 15, columns e, lines 28 -34, and 36. Gas: U-21981, Exhibit No. A-24 (SHB-9), page 16, column e, lines 31, 32, 34, 35, 37, 39, 42
4	2025	$ 1,644,388	Electric: U-22070, Exhibit No. A-22 (SHB-7), page 14, column e, lines 28 - 34 and 35.
5	Total Company Four-year Historical Average 2022 - 2025	$ 1,082,998	Used to project 2027 and 2028 costs
6	Electric Allocation Four-year Historical Average 2022 - 2025	$ 717,378	Used to project 2027 and 2028 costs

*Note: In 2021, 2022, and 2023 Field Device new purchases were a part of ARP-Workstation Asset Management and not ARP-FDAM.

EXHIBIT A-26 (SHB-11)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Test Year Enhancement Capital Expenditures and O&M Expense Summary and Analysis
Information Technology
For Years 2023 Through 2025 and Projected 2027, 2028, and Test Year
Electric Allocation

Case No.: U-22070
Exhibit No.: A-27 (SHB-12)
Page: 1 of 1
Witness: SHBaker
Date: June 2026

(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Capital							O&M						
		Total Company				Electric Allocation			Total Company				Electric Allocation		
Line No.	Enhancement Project	2023 Actuals	2024 Actuals	2025 Actuals	Three-Year Historical Average 2023 - 2025	2027 Projected	2028 Projected	Projected Test Year	2023 Actuals	2024 Actuals	2025 Actuals	Three-Year Historical Average 2023 - 2025	2027 Projected	2028 Projected	Projected Test Year
	Enhancements-Security-Capital														
1	Enhancements-Security-Capital	1,788,036	411,984	404,105					191,713	36,541	20,152				
2	**Total Enhancements-Security-Capital**	**1,788,036**	**411,984**	**404,105**	**868,042**	**574,991**	**574,991**	**574,991**	**191,713**	**36,541**	**20,152**	**82,802**	**52,165**	**52,165**	**52,165**
	Enhancements-Security-O&M														
3	Enhancements-Security-O&M	0	0	0					612,854	580,620	324,065				
4	**Total Enhancements-Security-O&M**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**612,854**	**580,620**	**324,065**	**505,846**	**270,274**	**270,274**	**270,274**
	Product Family Enhancements-Application Platforms Services-Capital														
5	Enhancements-IT-Capital	84,073	28,315	4,220					37	27	0				
6	Product Family Enhancements-Application Platforms Services-Capital	0	389,420	293,465					0	7,949	59,854				
7	Product Family Enhancements-IT/Digital Foundation-Capital	133,998	0	0					23,915	0	0				
8	**Total Product Family Enhancements-Application Platforms Services-Capital**	**218,071**	**417,735**	**297,685**	**311,164**	**206,115**	**206,115**	**206,115**	**23,952**	**7,976**	**59,854**	**30,594**	**19,274**	**19,274**	**19,274**
	Product Family Enhancements-Application Platforms Services-O&M														
9	Enhancements-IT-O&M	0	0	0					36,796	1,819	0				
10	Product Family Enhancements-Application Platforms Services-O&M	0	0	0					0	309,860	102,068				
11	Product Family Enhancements-IT/Digital Foundation-O&M	0	0	0					20,070	0	0				
12	**Total Product Family Enhancements-Application Platforms Services-O&M**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**56,866**	**311,679**	**102,068**	**156,871**	**83,816**	**83,816**	**83,816**
	Product Family Enhancements-Corporate-Capital														
13	Enhancements-Corporate Services-Capital	144,162	0	0					40,989	0	0				
14	Enhancements-IT-Capital	33,629	11,326	1,688					15	11	0				
15	Product Family Enhancements-Corporate-Capital	929,170	1,256,844	665,241					36,253	132,658	3,130				
16	Product Family Enhancements-IT/Digital Foundation-Capital	53,599	0	0					9,566	0	0				
17	**Total Product Family Enhancements-Corporate-Capital**	**1,160,559**	**1,268,170**	**666,929**	**1,031,886**	**683,521**	**683,521**	**683,521**	**86,823**	**132,669**	**3,130**	**74,208**	**46,751**	**46,751**	**46,751**
	Product Family Enhancements-Corporate-O&M														
18	Enhancements-Corporate Services-O&M								40,143	0	0				
19	Enhancements-IT-O&M	0	0	0					14,718	728	0				
20	Product Family Enhancements-Corporate-O&M	0	0	0					214,037	397,294	384,629				
21	Product Family Enhancements-IT/Digital Foundation-O&M	0	0	0					8,028	0	0				
22	**Total Product Family Enhancements-Corporate-O&M**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**276,926**	**398,021**	**384,629**	**353,192**	**188,711**	**188,711**	**188,711**
	Product Family Enhancements-Customer-Capital														
23	Enhancements - Customer Experience and Operations- Cap	702,678	563,792	354,329					75,876	41,582	68,530				
24	Enhancements-CX&O-Capital	895,691	0	0					148,193	0	0				
25	Product Family Enhancements-Customer-Capital	270,674	1,573,482	2,490,803					19,376	861,943	417,046				
26	**Total Product Family Enhancements-Customer-Capital**	**1,869,043**	**2,137,275**	**2,845,132**	**2,283,817**	**1,512,800**	**1,512,800**	**1,512,800**	**243,446**	**903,526**	**485,576**	**544,183**	**342,835**	**342,835**	**342,835**
	Product Family Enhancements-Customer-O&M														
27	Enhancements-CX&O-O&M	0	0	0					147,434	141,907	220,846				
28	Product Family Enhancements-Customer-O&M	0	0	0					98,349	76,214	19,252				
29	**Total Product Family Enhancements-Customer-O&M**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**245,783**	**218,121**	**240,098**	**234,667**	**147,840**	**147,840**	**147,840**
	Product Family Enhancements-Electric & Gas Shared-Capital														
30	Enhancements-TEOS-Capital	449,916	17,468	0					41,913	1,576	0				
31	Product Family Enhancements-Electric & Gas Shared-Capital	113,252	1,538,445	3,359,801					0	394,820	484,922				
32	**Total Product Family Enhancements-Electric & Gas Shared-Capital**	**563,168**	**1,555,913**	**3,359,801**	**1,826,294**	**1,209,737**	**1,209,737**	**1,209,737**	**41,913**	**396,396**	**484,922**	**307,743**	**193,878**	**193,878**	**193,878**
	Product Family Enhancements-Electric & Gas Shared-O&M														
33	Enhancements-TEOS-O&M	0	0	0					126,835	0	0				
34	Product Family Enhancements-Electric & Gas Shared-O&M	0	0	0					28,755	77,129	1,465,381				
35	**Total Product Family Enhancements-Electric & Gas Shared-O&M**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**155,590**	**77,129**	**1,465,381**	**566,034**	**302,432**	**302,432**	**302,432**
	Product Family Enhancements-Electric-Capital														
36	Product Family Enhancements-Electric-Capital	963,528	563,082	631,426					291,010	217,469	57,212				
37	**Total Product Family Enhancements-Electric-Capital**	**963,528**	**563,082**	**631,426**	**719,345**	**719,345**	**719,345**	**719,345**	**291,010**	**217,469**	**57,212**	**188,564**	**118,795**	**118,795**	**118,795**
	Product Family Enhancements-Electric-O&M														
38	Product Family Enhancements-Electric-O&M	0	0	0					106,083	141,790	113,607				
39	**Total Product Family Enhancements-Electric-O&M**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**106,083**	**141,790**	**113,607**	**120,493**	**64,379**	**64,379**	**64,379**
	Product Family Enhancements-Infrastructure Platforms Services-Capital														
40	Enhancements-Cloud Automation	314,721	0	0					190,501	0	0				
41	Enhancements-IT-Capital	50,444	16,989	2,532					22	16	0				
42	Product Family Enhancements-Infrastructure Platforms Services-Capital	0	547,715	196,032					0	79,958	105,266				
43	Product Family Enhancements-IT/Digital Foundation-Capital	80,399	0	0					14,349	0	0				
44	**Total Product Family Enhancements-Infrastructure Platforms Services-Capital**	**445,563**	**564,704**	**198,564**	**402,944**	**266,910**	**266,910**	**266,910**	**204,873**	**79,974**	**105,266**	**130,038**	**81,924**	**81,924**	**81,924**
	Product Family Enhancements-Infrastructure Platforms Services-O&M														
45	Enhancements-IT-O&M	0	0	0					22,077	1,091	0				
46	Product Family Enhancements-Infrastructure Platforms Services-O&M	0	0	0					0	144,022	41,219				
47	Product Family Enhancements-IT/Digital Foundation-O&M	0	0	0					12,042	0	0				
48	**Total Product Family Enhancements-Infrastructure Platforms Services-O&M**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**34,119**	**145,113**	**41,219**	**73,484**	**39,262**	**39,262**	**39,262**
49	**Total Enhancements**	**7,007,968**	**6,918,862**	**8,403,642**	**7,443,491**	**5,173,419**	**5,173,419**	**5,173,419**	**2,571,951**	**3,647,024**	**3,887,179**	**3,368,718**	**1,952,337**	**1,952,337**	**1,952,337**

EXHIBIT A-28 (SHB-13)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-29 (SHB-14)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Schedule D-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Overall Rate of Return Summary
for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-14 (MRB-1)
Schedule: D-1
Page: 1 of 1
Witness: MRBleckman
Date: June 2026

Line No.	(a) Description	(b) Capital Structure Amount ($000,000) (1)	(c) Capital Structure Percent Permanent Capital (2)	(d) Capital Structure Percent of Total Capital	(e) Cost Rate %	(f) Weighted Cost Permanent Capital (7)	(g) Weighted Cost Total Cost % (8)	(h) Weighted Cost Conversion Factor	(i) Weighted Cost Pre-Tax Return (9)
1									
2	Long-Term Debt	$ 15,515	48.13%	41.50%	4.72% (3)	2.27%	1.96%	1.0000	1.96%
3									
4	Preferred Stock	37	0.12%	0.10%	4.50% (4)	0.01%	0.00%	1.3381	0.01%
5									
6	Common Shareholder's Equity	16,681	51.75%	44.62%	10.25% (5)	5.30%	4.57%	1.3381	6.12%
7									
8	Total Permanent Capital	$ 32,233	100.00%						
9									
10	Short-Term Debt	156		0.42%	4.94% (6)		0.02%	1.0000	0.02%
11									
12	Deferred Income Taxes	4,843		12.96%	0.00%		0.00%	1.0000	0.00%
13									
14	Investment Tax Credit								
15	Long-Term Debt	75		0.20%	4.72%		0.01%	1.0000	0.01%
16	Preferred Stock	0		0.00%	4.50%		0.00%	1.3381	0.00%
17	Common Equity	75		0.20%	10.25%		0.02%	1.3381	0.03%
18									
19	Total	$ 37,382		100.00%			6.59%		8.14%

(1) See Exhibit A-14 (MRB-2), Schedule D-1a, Page 1.
(2) Excludes Short-term Debt, Deferred Income Taxes, and Investment Tax Credit to calculate the rate of return for Investment Tax Credit purposes in accordance with Internal Revenue Service Income Tax Regulation Section 1.46-6.
(3) See Exhibit A-14 (MRB-4), Schedule D-2.
(4) See Exhibit A-14 (MRB-6), Schedule D-4.
(5) See Exhibit A-14 (AEB-1), Schedule D-5.
(6) See Exhibit A-14 (MRB-5), Schedule D-3, Page 1.
(7) Column (c) x column (e).
(8) Column (d) x column (e).
(9) Column (g) x column (h).

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development
for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
Page: 1 of 4
Witness: MRBleckman
Date: June 2026

Line No.	(a) Description	(b) Historical Capital Structure 13-Month Avg. For Yr. Ended December 31, 2025 Amount Outstanding (000,000)	(c) % of Permanent Capital	(d) % of Total Capital	(e) Balances as of Dec. 31, 2025 (000,000)	(f) Test Year Adjustments (000,000)	(g) Recommended Capital Structure Amount Outstanding (000,000)	(h) % of Permanent Capital	(i) % of Total Capital
1									
2	Long-Term Debt	$ 12,082	50.45%	42.31%	$ 12,514	$ 3,001	$ 15,515	48.13%	41.50%
3									
4	Preferred Stock	37	0.16%	0.13%	37	-	37	0.12%	0.10%
5									
6	Common Equity	11,829	49.39%	41.42%	12,556	4,125	16,681	51.75%	44.62%
7									
8	Total Permanent Capital	$ 23,948	100.00%		$ 25,107	$ 7,126	$ 32,233	100.00%	
9									
10	Short-Term Debt	103		0.36%	340	(184)	156		0.42%
11									
12	Deferred Income Taxes	4,385		15.35%	4,455	388	4,843		12.96%
13									
14	Investment Tax Credit								
15	Long-Term Debt	61		0.21%	59	16	75		0.20%
16	Preferred Stock	0		0.00%	0	0	0		0.00%
17	Common Equity	59		0.21%	59	16	75		0.20%
18									
19	Total Investment Tax Credit	120		0.42%	118	32	150		0.40%
20									
21	Total Capitalization	$ 28,556		100.00%	$ 30,020	$ 7,362	$ 37,382		100.00%

Sources and Support, by Column:

(b) Consumers Energy General Ledger 13-month average balances as of December 31, 2025.
(c) Each line 2, 4, and 6 in column (b) is divided by line 8, column (b).
(d) Each line 2, 4, 6, 10, 12, 15, 16, 17, and 19 in column (b) is divided by line 21, column (b).
(e) Consumers Energy General Ledger balances as of December 31, 2025.
(f) Line 2 Debt maturities and debt issues, line 6 Adjustment for retained earnings and equity contributions, line 10 Adjustment to project short-term debt, line 12 Adjustment to project Deferred Income Taxes balance, lines 15-17 Adjustment to project Investment Tax Credit balance.
(g) Column (e) + column (f). Represents 13-month averages.
(h) Each line 2, 4, and 6 in column (g) is divided by line 8, column (g).
(i) Each line 2, 4, 6, 10, 12, 15, 16, 17, and 19 in column (g) is divided by line 21, column (g).

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development - Projected Long-Term Debt Balance
for the Projected Year Ending April 30, 2028
(in millions)

Case No.: U-22070
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
Page: 2 of 4
Witness: MRBleckman
Date: June 2026

Line No.	(a) Long-Term Debt	(b) Actual Jan-25	(c) Actual Feb-25	(d) Actual Mar-25	(e) Actual Apr-25	(f) Actual May-25	(g) Actual Jun-25	(h) Actual Jul-25	(i) Actual Aug-25	(j) Actual Sep-25	(k) Actual Oct-25	(l) Actual Nov-25	(m) Actual Dec-25
1													
2	Beginning Balance	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 12,630
3	Add: Issuances	-	-	-	-	1,125	-	-	-	-	-	-	-
4	Less: Retirements	-	-	-	-	-	-	-	-	-	-	-	-
5	Subtotal	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 12,630
6													
7	Less: Unamortized Fees	(113)	(112)	(111)	(110)	(120)	(119)	(119)	(118)	(117)	(116)	(117)	(116)
8													
9	Ending Balance	$ 11,392	$ 11,393	$ 11,394	$ 11,395	$ 12,510	$ 12,511	$ 12,511	$ 12,512	$ 12,513	$ 12,514	$ 12,513	$ 12,514
10													
11													
12													
13	Long-Term Debt	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
14													
15	Beginning Balance	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 13,290	$ 13,290	$ 13,290	$ 14,250	$ 14,250	$ 14,250	$ 14,250
16	Add: Issuances	-	-	-	-	775	-	-	960	-	-	-	-
17	Less: Retirements	-	-	-	-	(115)	-	-	-	-	-	-	-
18	Subtotal	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 13,290	$ 13,290	$ 13,290	$ 14,250	$ 14,250	$ 14,250	$ 14,250	$ 14,250
19													
20	Less: Unamortized Fees	(115)	(114)	(113)	(112)	(119)	(118)	(117)	(124)	(123)	(122)	(121)	(120)
21													
22	Ending Balance	$ 12,515	$ 12,516	$ 12,517	$ 12,518	$ 13,171	$ 13,172	$ 13,173	$ 14,126	$ 14,127	$ 14,128	$ 14,129	$ 14,130
23													
24													
25													
26	Long-Term Debt	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
27													
28	Beginning Balance	$ 14,250	$ 14,250	$ 14,250	$ 14,250	$ 14,250	$ 15,200	$ 15,200	$ 15,200	$ 16,135	$ 16,135	$ 16,035	$ 16,035
29	Add: Issuances	-	-	-	-	950	-	-	935	-	-	-	-
30	Less: Retirements	-	-	-	-	-	-	-	-	-	(100)	-	(36)
31	Subtotal	$ 14,250	$ 14,250	$ 14,250	$ 14,250	$ 15,200	$ 15,200	$ 15,200	$ 16,135	$ 16,135	$ 16,035	$ 16,035	$ 15,999
32													
33	Less: Unamortized Fees	(119)	(118)	(117)	(116)	(124)	(123)	(122)	(132)	(131)	(130)	(129)	(128)
34													
35	Ending Balance	$ 14,131	$ 14,132	$ 14,133	$ 14,134	$ 15,076	$ 15,077	$ 15,078	$ 16,003	$ 16,004	$ 15,905	$ 15,906	$ 15,871
36													
37													
38													
39	Long-Term Debt	Jan-28	Feb-28	Mar-28	Apr-28								
40													
41	Beginning Balance	$ 15,999	$ 15,999	$ 15,999	$ 15,574								
42	Add: Issuances	-	-	-	-								
43	Less: Retirements	-	-	(425)	-								
44	Subtotal	$ 15,999	$ 15,999	$ 15,574	$ 15,574								
45													
46	Less: Unamortized Fees	(127)	(126)	(125)	(124)								
47													
48	Ending Balance	$ 15,872	$ 15,873	$ 15,449	$ 15,450								
49													
50	**Test Year 13-Month Average:**												
51	Subtotal				$ 15,641								
52	Less: Unamortized Fees				(126)								
53	Ending Balance				**$ 15,515**								

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development - Projected Common Equity Balance
for the Projected Year Ending April 30, 2028
(in millions)

Case No.: U-22070
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
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Date: June 2026

Line No.	(a) Common Equity	(b) Actual Jan-25	(c) Actual Feb-25	(d) Actual Mar-25	(e) Actual Apr-25	(f) Actual May-25	(g) Actual Jun-25	(h) Actual Jul-25	(i) Actual Aug-25	(j) Actual Sep-25	(k) Actual Oct-25	(l) Actual Nov-25	(m) Actual Dec-25
1													
2	Beginning Balance	$ 11,405	$ 11,567	$ 11,579	$ 11,630	$ 11,484	$ 11,505	$ 11,672	$ 11,594	$ 11,985	$ 12,299	$ 12,090	$ 12,410
3	Ret. Earnings	162	(138)	51	(146)	21	167	(78)	116	44	(209)	95	146
4	Equity Infusion	-	150	-	-	-	-	-	275	270	-	225	-
5	Ending Balance	$ 11,567	$ 11,579	$ 11,630	$ 11,484	$ 11,505	$ 11,672	$ 11,594	$ 11,985	$ 12,299	$ 12,090	$ 12,410	$ 12,556
6													
7													
8													
9	Common Equity	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
10													
11	Beginning Balance	$ 12,556	$ 12,743	$ 12,951	$ 12,992	$ 13,011	$ 13,030	$ 14,003	$ 14,022	$ 14,041	$ 14,060	$ 14,078	$ 14,097
12	Ret. Earnings	187	(192)	41	19	19	19	19	19	19	19	19	19
13	Equity Infusion	-	400	-	-	-	955	-	-	-	-	-	-
14	Ending Balance	$ 12,743	$ 12,951	$ 12,992	$ 13,011	$ 13,030	$ 14,003	$ 14,022	$ 14,041	$ 14,060	$ 14,078	$ 14,097	$ 14,116
15													
16													
17													
18	Common Equity	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
19													
20	Beginning Balance	$ 14,116	$ 14,135	$ 15,304	$ 15,322	$ 15,341	$ 15,360	$ 16,529	$ 16,548	$ 16,566	$ 16,585	$ 16,604	$ 16,623
21	Ret. Earnings	19	19	19	19	19	19	19	19	19	19	19	19
22	Equity Infusion	-	1,150	-	-	-	1,150	-	-	-	-	-	-
23	Ending Balance	$ 14,135	$ 15,304	$ 15,322	$ 15,341	$ 15,360	$ 16,529	$ 16,548	$ 16,566	$ 16,585	$ 16,604	$ 16,623	$ 16,641
24													
25													
26													
27	Common Equity	Jan-28	Feb-28	Mar-28	Apr-28								
28													
29	Beginning Balance	$ 16,641	$ 16,660	$ 17,779	$ 17,798								
30	Ret. Earnings	19	19	19	19								
31	Equity Infusion	-	1,100	-	-								
32	Ending Balance	$ 16,660	$ 17,779	$ 17,798	$ 17,817								
33													
34													
35	**Test Year 13-Month Average**				**$ 16,681**								

(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Test Year Impact of Retained Earnings			Test Year Impact of Equity Infusions		
	2026	**2027**	**2028**	**2026**	**2027**	**2028**
Jan	$ 187	$ 224	$ 449	$ -	$ 1,355	$ 3,655
Feb	$ (5)	$ 243	$ 468	$ 400	$ 2,505	$ 4,755
Mar	$ 36	$ 261	$ 487	$ 400	$ 2,505	$ 4,755
Apr	$ 55	$ 280	$ 506	$ 400	$ 2,505	$ 4,755
May	$ 74	$ 299		$ 400	$ 2,505	
Jun	$ 92	$ 318		$ 1,355	$ 3,655	
Jul	$ 111	$ 337		$ 1,355	$ 3,655	
Aug	$ 130	$ 355		$ 1,355	$ 3,655	
Sep	$ 149	$ 374		$ 1,355	$ 3,655	
Oct	$ 167	$ 393		$ 1,355	$ 3,655	
Nov	$ 186	$ 412		$ 1,355	$ 3,655	
Dec	$ 205	$ 430		$ 1,355	$ 3,655	
13-Month Avg.			$ 393			$ 3,732

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development - Projected Deferred Income Tax Balance
for the Projected Year Ending April 30, 2028
(in millions)

Case No.: U-22070
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
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Witness: MRBleckman
Date: June 2026

Deferred Income Tax Ending Balance

Line No.	(a) Actual Jan-25	(b) Actual Feb-25	(c) Actual Mar-25	(d) Actual Apr-25	(e) Actual May-25	(f) Actual Jun-25	(g) Actual Jul-25	(h) Actual Aug-25	(i) Actual Sep-25	(j) Actual Oct-25	(k) Actual Nov-25	(l) Actual Dec-25
1	$ 4,302	$ 4,314	$ 4,327	$ 4,340	$ 4,353	$ 4,366	$ 4,378	$ 4,391	$ 4,404	$ 4,417	$ 4,430	$ 4,442
2												
3												
4												
5	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
6	$ 4,471	$ 4,486	$ 4,502	$ 4,518	$ 4,534	$ 4,549	$ 4,565	$ 4,581	$ 4,596	$ 4,612	$ 4,628	$ 4,644
7												
8												
9												
10	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
11	$ 4,664	$ 4,684	$ 4,704	$ 4,724	$ 4,744	$ 4,765	$ 4,785	$ 4,805	$ 4,825	$ 4,845	$ 4,865	$ 4,886
12												
13												
14												
15	Jan-28	Feb-28	Mar-28	Apr-28								
16	$ 4,903	$ 4,921	$ 4,938	$ 4,956								
17												
18												
19	**Test Year 13-Month Average**			**$ 4,843**								

Schedule D-1b

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Development of Capital Structure
for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-14 (MRB-3)
Schedule: D-1b
Page: 1 of 1
Witness: MRBleckman
Date: June 2026

Line No.	(a) Description	(b) Financial Basis	(c) MPSC Ratemaking Basis
I.	LONG-TERM DEBT:		
a.	First Mortgage Bonds	Include	Include
b.	Trust Preferred Securities	Include	Include
c.	Other Subordinated LTD	Include	Include
d.	Unamortized Debt Premium	Include	Include
e.	Unamortized Debt Discount	Include	Include
f.	Unamortized Debt Expense	Include	Include
g.	Current Maturities	**Exclude**	**Include**
h.	Capitalized Leases	**Include**	**Exclude**
II.	SHORT-TERM DEBT	Include	Include
III.	PREFERRED STOCK EXPENSE		
a.	Preferred Stock	Include	Include
b.	Trust Preferred Securities	Exclude	Exclude
c.	Preferred Stock Expense	Include	Include
IV.	COMMON EQUITY		
a.	Common Stock Issued	Include	Include
b.	Premium on Common Stock	Include	Include
c.	Donations Received From Stockholders	Include	Include
d.	Common Stock Expense	Include	Include
e.	Gain on Reacquired Stock	Include	Include
f.	Miscellaneous Paid In Capital	Include	Include
g.	Mark-to-Market Accounting	**Include**	**Exclude**
h.	Appropriated Retained Earnings	Include	Include
I.	Unappropriated Retained Earnings	Include	Include
j.	FAS 90 (Abandoned Plant)	Include	Include
V.	DEFERRED ITC	**Exclude**	**Include**
VI.	DEFERRED TAXES	**Exclude**	**Include**
VII.	DEFERRED JDITC	**Exclude**	**Include**

Schedule D-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Long-Term Debt
for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-14 (MRB-4)
Schedule: D-2
Page: 1 of 1
Witness: MRBleckman
Date: June 2026

Line No.	(a) Description	(b) Original Issue Date	(c) Stated Maturity Date	(d) Interest Rate (%)	(d1) Interest Payments Per Year	(e) Amount of Offering ($000)	(f) Price to Public (%)	(g) Underwriting Expenses (%)	(g1) Underwriting Expenses ($000)	(g2) Financing Expenses (%)	(g3) Financing Expenses ($000)	(g4) (Premium) Discount ($000)	(h) Net Proceeds to the Company (%)	(i) Cost Based on Net Proceeds (%)	(j) Amount Outstanding ($000)	(k) Annual Cost ($000)
1																
2	**Mortgage Bonds**															
3	5.800%	11-Aug-05	15-Sep-35	5.800%	2	175,000	99.81%	0.875%	1,531.25	0.17%	299.97	337.75	98.761%	5.8879%	175,000	10,304
4	6.170%	01-Sep-10	01-Sep-40	6.170%	2	50,000	100.00%	0.906%	453.04	0.08%	38.99	0.00	99.016%	6.2430%	50,000	3,121
5	4.970%	15-Oct-10	15-Oct-40	4.970%	2	50,000	100.00%	0.500%	250.00	0.04%	19.58	0.00	99.461%	5.0049%	50,000	2,502
6	3.390%	17-Dec-12	15-Dec-27	3.390%	2	35,500	100.00%	0.501%	178.03	0.04%	13.76	0.00	99.460%	3.4364%	21,846	751
7	4.310%	17-Dec-12	15-Dec-42	4.310%	2	263,000	100.00%	0.501%	1,318.92	0.03%	68.78	0.00	99.472%	4.3416%	263,000	11,418
8	3.950%	17-May-13	15-May-43	3.950%	2	425,000	99.84%	0.875%	3,718.75	0.16%	675.43	667.25	98.809%	4.0187%	425,000	17,079
9	4.350%	18-Aug-14	31-Aug-64	4.350%	2	250,000	99.14%	0.875%	2,187.50	0.12%	309.64	2,157.50	98.138%	4.4430%	250,000	11,107
10	4.100%	06-Nov-15	15-Nov-45	4.100%	2	250,000	99.91%	0.875%	2,187.50	0.18%	447.46	217.50	98.859%	4.1669%	250,000	10,417
11	3.250%	10-Aug-16	15-Aug-46	3.250%	2	450,000	99.22%	0.875%	3,937.50	0.18%	821.46	3,501.00	98.164%	3.3474%	450,000	15,063
12	3.950%	22-Feb-17	15-Jul-47	3.950%	2	350,000	99.58%	0.875%	3,062.50	0.19%	669.34	1,463.00	98.516%	4.0350%	350,000	14,122
13	3.18% (Private Placement)	28-Sep-17	28-Sep-32	3.180%	2	40,000	100.00%	0.301%	120.48	0.03%	12.80	0.00	99.667%	3.2082%	40,000	1,283
14	3.52% (Private Placement)	28-Sep-17	28-Sep-37	3.520%	2	125,000	100.00%	0.402%	501.98	0.04%	53.33	0.00	99.556%	3.5512%	125,000	4,439
15	3.86% (Private Placement)	28-Sep-17	28-Sep-52	3.860%	2	20,000	100.00%	0.703%	140.56	0.07%	14.93	0.00	99.223%	3.9009%	20,000	780
16	3.18% (Private Placement)	15-Nov-17	15-Nov-32	3.180%	2	60,000	100.00%	0.301%	180.71	0.03%	18.60	0.00	99.668%	3.2081%	60,000	1,925
17	3.52% (Private Placement)	15-Nov-17	15-Nov-37	3.520%	2	210,000	100.00%	0.402%	843.33	0.04%	86.81	0.00	99.557%	3.5511%	210,000	7,457
18	3.86% (Private Placement)	15-Nov-17	15-Nov-52	3.860%	2	30,000	100.00%	0.703%	210.83	0.07%	21.70	0.00	99.225%	3.9008%	30,000	1,170
19	4.050%	14-May-18	15-May-48	4.050%	2	550,000	98.97%	0.875%	4,812.50	0.20%	1,106.61	5,659.50	97.895%	4.1737%	550,000	22,955
20	3.68% (Private Placement)	01-Oct-18	01-Oct-27	3.680%	2	100,000	100.00%	0.145%	145.00	0.01%	13.99	0.00	99.841%	3.7009%	46,154	1,708
21	4.01% (Private Placement)	01-Oct-18	01-Oct-38	4.010%	2	215,000	100.00%	0.323%	694.00	0.03%	56.32	0.00	99.651%	4.0356%	215,000	8,677
22	4.28% (Private Placement)	01-Oct-18	01-Oct-57	4.280%	2	185,000	100.00%	0.629%	1,164.00	0.05%	87.47	0.00	99.324%	4.3160%	185,000	7,985
23	3.800%	13-Nov-18	15-Nov-28	3.800%	2	300,000	99.75%	0.650%	1,950.00	0.10%	305.05	744.00	99.000%	3.9217%	300,000	11,765
24	4.350%	13-Nov-18	15-Apr-49	4.350%	2	550,000	99.62%	0.875%	4,812.50	0.18%	985.10	2,101.00	98.564%	4.4363%	550,000	24,400
25	3.750%	28-May-19	15-Feb-50	3.750%	2	300,000	98.83%	0.875%	2,625.00	0.21%	632.06	3,498.00	97.748%	3.8758%	300,000	11,627
26	3.100%	03-Sep-19	15-Aug-50	3.100%	2	550,000	99.29%	0.875%	4,812.50	0.10%	526.98	3,899.50	98.320%	3.1857%	550,000	17,521
27	Floating Rate FMB	19-Sep-19	15-Sep-69	3.380%	4	75,649	100.00%	1.000%	756.49	0.99%	751.55	0.00	98.007%	3.4640%	75,649	2,621
28	3.500%	26-Mar-20	01-Aug-51	3.500%	2	575,000	100.00%	0.875%	5,031.25	0.22%	1,261.45	0.00	98.906%	3.5580%	575,000	20,459
29	2.500%	13-May-20	01-May-60	2.500%	2	525,000	100.00%	0.875%	4,593.75	0.17%	905.40	0.00	98.953%	2.5419%	525,000	13,345
30	Floating Rate FMB	20-May-20	20-May-70	3.380%	4	134,349	100.00%	1.000%	1,343.49	0.29%	390.52	0.00	98.709%	3.4341%	134,349	4,614
31	Floating Rate FMB	07-Oct-20	07-Oct-70	3.380%	4	126,497	100.00%	1.000%	1,264.97	0.25%	315.63	0.00	98.750%	3.4324%	126,497	4,342
32	2.650%	12-Aug-21	15-Aug-52	2.650%	2	300,000	99.92%	0.875%	2,625.00	0.19%	569.00	252.00	98.851%	2.7050%	300,000	8,115
33	3.600%	11-Aug-22	15-Aug-32	3.600%	2	350,000	99.93%	0.650%	2,275.00	0.20%	700.00	262.50	99.075%	3.7114%	350,000	12,990
34	4.200%	11-Aug-22	01-Sep-52	4.200%	2	450,000	99.93%	0.875%	3,937.50	0.20%	900.00	319.50	98.854%	4.2679%	450,000	19,206
35	4.650%	10-Jan-23	01-Mar-28	4.650%	2	425,000	99.81%	0.600%	2,550.00	0.20%	850.00	790.50	99.014%	4.8680%	359,615	17,506
36	4.625%	23-Feb-23	15-May-33	4.625%	2	700,000	100.00%	0.650%	4,550.00	0.20%	1,400.00	0.00	99.150%	4.7300%	700,000	33,110
37	5.07% (Private Placement)	15-May-23	15-May-29	5.070%	2	50,000	100.00%	0.875%	437.50	0.20%	100.00	0.00	98.925%	5.2814%	50,000	2,641
38	5.17% (Private Placement)	15-May-23	15-May-32	5.170%	2	95,000	100.00%	0.875%	831.25	0.20%	190.00	0.00	98.925%	5.3219%	95,000	5,056
39	5.38% (Private Placement)	15-May-23	15-May-37	5.380%	2	140,000	100.00%	0.875%	1,225.00	0.20%	280.00	0.00	98.925%	5.4910%	140,000	7,687
40	4.900%	04-Aug-23	15-Feb-29	4.900%	2	500,000	99.95%	0.600%	3,000.00	0.12%	582.56	250.00	99.233%	5.0603%	500,000	25,301
41	4.600%	09-Jan-24	30-May-29	4.600%	2	600,000	99.77%	0.600%	3,600.00	0.10%	625.48	1,392.00	99.064%	4.7982%	600,000	28,789
42	4.700%	05-Aug-24	15-Jan-30	4.700%	2	700,000	99.78%	0.600%	4,200.00	0.11%	782.00	1,575.00	99.063%	4.8975%	700,000	34,283
43	4.500%	02-May-25	15-Jan-31	4.500%	2	500,000	99.97%	0.600%	3,000.00	0.16%	776.16	145.00	99.216%	4.6569%	500,000	23,284
44	5.050%	02-May-25	15-May-35	5.050%	2	625,000	99.63%	0.650%	4,062.50	0.21%	1,308.50	2,300.00	98.773%	5.2083%	625,000	32,552
45	New Debt Issue #1	01-May-26	01-May-56	6.340%	2	775,000	100.00%	0.875%	6,781.25	0.20%	1,550.00	0.00	98.925%	6.4212%	775,000	49,764
46	New Debt Issue #2	01-Aug-26	01-Aug-56	6.350%	2	960,000	100.00%	0.875%	8,400.00	0.20%	1,920.00	0.00	98.925%	6.4313%	960,000	61,741
47	New Debt Issue #3	01-May-27	01-May-57	6.380%	2	950,000	100.00%	0.875%	8,312.50	0.20%	1,900.00	0.00	98.925%	6.4616%	876,923	56,663
48	New Debt Issue #4	01-Aug-27	01-Aug-57	6.390%	2	935,000	100.00%	0.875%	8,181.25	0.20%	1,870.00	0.00	98.925%	6.4717%	647,308	41,892
49	Total Mortgage Bonds														$ 15,531,341	$ 725,538
50																
51	**Other Long-Term Debt**															
52	PCRB - MSF LORB - 19	01-Oct-19	01-Oct-49	3.350%	2	75,000	100.00%	0.592%	443.75	0.89%	669.74	0.00	98.515%	3.4296%	$ 75,000	$ 2,572
53	PCRB - MSF LORB - 21	07-Oct-21	01-Apr-35	0.875%	2	35,000	100.00%	0.600%	210.00	0.90%	315.00	0.00	98.500%	0.9941%	35,000	348
54															$ 110,000	$ 2,920
55																
56																
57	Total Long-Term Debt														$ 15,641,341	$ 728,458
58																
59	Amortization of Losses on Reacquired Debt with Refunding (including Call Premiums)															4,416
60																
61	Total Long-Term Debt Before Unamortized Expense and Premium													4.69%	$ 15,641,341	$ 732,874
62																
63	Unamortized Debt Discount, Expense and Premium														(125,923)	
64																
65	Total Long-Term Debt Balance														$ 15,515,418	
66																
67	Annual Cost													4.72%		
68																

Ties to 13-Month Average in Exhibit A-14 (MRB-2), Schedule D-1a, pg. 2

Calculations:

Column (i) = Yield formula based on inputs from column (b),column (c), column (d), column (d1), and column (h) calculated on an annualized basis.
Column (j) = Represents the average amount of debt outstanding for the test year.
Column (k) = column (i)*column (j).
Lines 27, 30, and 31 Coupon Rate = Projected SOFR Rate of 3.42% minus 0.04%.
Lines 6, 20, 35, 47, and 48 - As this is a partial year debt outstanding, pro-rata balance and pro-rata interest expense are used which would result in the same cost rate as an annual analysis, but provides a more accurate average debt balance for the Test Year. This would make the Total Debt balance line 65 tie to the debt balance shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.
Line 59 - Amortization of losses on reacquired debt projected for the test year ending April 30, 2028.

Projected SOFR Rate	Test Year Avg.
Bloomberg (Apr. 20, 2026)	3.42%

Projected New Debt Issue Interest Rates	New Debt #1 May 2026	New Debt #2 Aug. 2026	New Debt #3 May 2027	New Debt #4 Aug. 2027
Projected 30-Yr Treasury Rate (Bloomberg)	5.00%	5.01%	5.04%	5.05%
Add: Historical 30-Year Bond Spread	1.34%	1.34%	1.34%	1.34%
	6.34%	**6.35%**	**6.38%**	**6.39%**

Schedule D-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Short-Term Debt
for the Projected Year Ending April 30, 2028
(in millions)

Case No.: U-22070
Exhibit No.: A-14 (MRB-5)
Schedule: D-3
Page: 1 of 2
Witness: MRBleckman
Date: June 2026

Line No.		(a) **Average Borrowings**	(b) **Cost of Borrowings**	(c) **Cost Rate**
1	Short-Term Debt	$ 156.0	$ 7.7	4.94%

Sources:
Column (a): Exhibit A-14 (MRB-7), Schedule D-6.
Column (b): Exhibit A-14 (MRB-5), Schedule D-3, page 2.
Column (c) = column (b)/column (a).

Schedule D-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Short-Term Debt
for the Projected Year Ending April 30, 2028
(in millions)

Case No.: U-22070
Exhibit No.: A-14 (MRB-5)
Schedule: D-3
Page: 2 of 2
Witness: MRBleckman
Date: June 2026

Summary

Line No.	Facility	Agreement Date	Expiration	Facility Amount	Test Year Assumption: Less: Avg. Borrowings (A)	Less: Letters of Credit (B)	Amount Unused[a] (C)	Upfront Fee Amort (D)
1	1. JPMorgan Revolver	Nov. 2025	Nov. 2030	$ 1,100.0	$ -	$ 53.1	$ 1,046.9	$ 0.4
2	2. Commercial Paper Facility	Sep. 2014	N/A	$ 500.0	$ 156.0	N/A	N/A	$ -
3	3. MUFG Revolver	Nov. 2025	Nov. 2028	$ 300.0	$ -	$ -	$ 300.0	$ 0.3
4	4. LC Facility - ScotiaBank	Nov. 2025	May 2027	$ 100.0	N/A	$ 27.7	N/A	$ -

Cost of Short-Term Debt

(A) **Interest on Borrowings** - Calculated on the projected drawn balance at SOFR plus the spread on borrowings.

Facility	SOFR[b]	Plus: Spread	Projected Rate	Avg. Borrowings	Cost
1. JPMorgan Revolver	3.42%	0.875%	4.30%	$ -	$ -
2. Commercial Paper Facility	3.42%	0.000%	3.42%	156.0	5.3
3. MUFG Revolver	3.42%	0.875%	4.30%	-	-
					$ 5.3

(B) **Letter of Credit Fees** - Calculated on the projected letters of credit outstanding at a rate equal to the spread.

Facility	Letter of Credit Type	Projected Rate	Letters of Credit	Cost
1. JPMorgan Revolver	Regular Operating	0.875%	$ 53.1	$ 0.5
2. Commercial Paper Facility	N/A	N/A	N/A	-
3. MUFG Revolver	N/A	0.875%	-	-
4. LC Facility - ScotiaBank	MISO Margin	0.850%	27.7	0.2
				$ 0.7

(C) **Unused (Commitment) Fees** - Calculated on the unused portion of the revolver at a rate stated in the facility agreement.

	Projected Rate	Amount Unused[a]	Cost
1. JPMorgan Revolver	0.075%	$ 1,046.9	$ 0.8
2. Commercial Paper Facility	N/A	N/A	-
3. MUFG Revolver	0.075%	$ 300.0	$ 0.2
			$ 1.0

(D) **Amortization / Expense of Facility Fees** - Fees paid upfront at the inception or amendment to the facility, amortized over the life of the facility.

	Annual Cost
1. JPMorgan Revolver	$ 0.4
2. Commercial Paper Facility	-
3. MUFG Revolver	0.3
	$ 0.7

Total Cost of Short-Term Debt **$ 7.7**

[a] Commercial Paper drawn balances go against, or are "backstopped," by the Company's JPMorgan Revolver. To the extent amounts are borrowed under the Commercial Paper Facility, the availability of the JPMorgan Revolver are reduced. These borrowings do not, however, reduce the "unused" portion of the revolver in calculating the unused (commitment) fees.

[b] Projected SOFR rate per Exhibit A-14 (MRB-4), Schedule D-2. Forecasted SOFR assumed to closely approximate commercial paper rate.

Schedule D-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Preferred Stock
for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-14 (MRB-6)
Schedule: D-4
Page: 1 of 1
Witness: MRBleckman
Date: June 2026

Line No.	(a) Description	(b) Annual Dividend	(c) Par Value	(d) Finance Expense	(e) (Premium) Discount	(f) Net Proceeds Received By Company	(g) Number Of Shares Outstanding	(h) Total Value Of Net Proceeds (000)	(i) Cost Rates	(j) Annual Cost (000)
	PREFERRED STOCK:									
1	$4.500 Series	$4.500	$100.00	$0.00	$0.00	$100.00	373,148	$37,315	4.50%	$1,679

Calculations:
Column (i) = (column (h)*column (b)/column (f))/column (h).
Column (j) = column (h)*column (i).

Schedule D-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Short-Term Debt Utilization
for the Projected Year Ending April 30, 2028
(in millions)

Case No.: U-22070
Exhibit No.: A-14 (MRB-7)
Schedule: D-6
Page: 1 of 1
Witness: MRBleckman
Date: June 2026

Ending Short-Term Debt

Line No.	(a) Actual Jan-25	(b) Actual Feb-25	(c) Actual Mar-25	(d) Actual Apr-25	(e) Actual May-25	(f) Actual Jun-25	(g) Actual Jul-25	(h) Actual Aug-25	(i) Actual Sep-25	(j) Actual Oct-25	(k) Actual Nov-25	(l) Actual Dec-25
1												
2	$ -	$ 161	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 202	$ 340
3												
4												
5	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
6												
7	$ 391	$ 587	$ 517	$ -	$ -	$ -	$ -	$ -	$ -	$ 288	$ 472	$ 480
8												
9												
10	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
11												
12	$ 312	$ 394	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 298	$ 462	$ 471
13												
14												
15	Jan-28	Feb-28	Mar-28	Apr-28								
16												
17	$ 410	$ 387	$ -	$ -								
18												
19	**Test Year 13-Month Avg**			**$ 156**								

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Current and Historical Credit Ratings
for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-32 (MRB-8)
Page: 1 of 1
Witness: MRBleckman
Date: June 2026

Line No.		Credit Ratings					
		(a)	(b)	(c)	(d)	(e)	(f)
1			Standard & Poors Ratings at Year End				
2		**Current**	**2025**	**2024**	**2023**	**2022**	**2021**
3	**Consumers Energy Company**						
4	Senior Secured Debt	A	A	A	A	A	A
5	Commercial Paper	A-2	A-2	A-2	A-2	A-2	A-2
6	Senior Unsecured Debt	N/A	N/A	N/A	N/A	N/A	N/A
7	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
8	Preferred Stock	N/A	N/A	N/A	N/A	N/A	N/A
9	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
10							
11	**CMS Energy Corporation**						
12	Senior Secured Debt	N/A	N/A	N/A	N/A	N/A	N/A
13	Senior Unsecured Debt	BBB	BBB	BBB	BBB	BBB	BBB
14	Junior Subordinated Debt	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-
15	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
16	Preferred Stock	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-
17	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
18							
19							
20			Moody's Ratings at Year End				
21		**Current**	**2025**	**2024**	**2023**	**2022**	**2021**
22	**Consumers Energy Company**						
23	Senior Secured Debt	A1	A1	A1	A1	A1	A1
24	Commercial Paper	P-2	P-2	P-2	P-2	P-2	P-2
25	Senior Unsecured Debt	N/A	N/A	N/A	N/A	N/A	N/A
26	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
27	Preferred Stock	Baa2	Baa1	Baa1	Baa1	Baa1	Baa1
28	Outlook	Negative	Stable	Stable	Stable	Stable	Stable
29							
30	**CMS Energy Corporation**						
31	Senior Secured Debt	A3	A3	A3	A3	A3	A3
32	Senior Unsecured Debt	Baa2	Baa2	Baa2	Baa2	Baa2	Baa2
33	Junior Subordinated Debt	Baa3	Baa3	Baa3	Baa3	Baa3	Baa3
34	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
35	Preferred Stock	Ba1	Ba1	Ba1	Ba1	Ba1	Ba1
36	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
37							
38							
39			Fitch Ratings at Year End				
40		**Current**	**2025**	**2024**	**2023**	**2022**	**2021**
41	**Consumers Energy Company**						
42	Senior Secured Debt	A+	A+	A+	A+	A+	A+
43	Commercial Paper	F-2	F-2	F-2	F-2	F-2	F-2
44	Senior Unsecured Debt	A	A	A	A	A	A
45	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
46	Preferred Stock	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
47	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
48							
49	**CMS Energy Corporation**						
50	Senior Secured Debt	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
51	Senior Unsecured Debt	BBB	BBB	BBB	BBB	BBB	BBB
52	Junior Subordinated Debt	BB+	BB+	BB+	BB+	BB+	BB+
53	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
54	Preferred Stock	BB+	BB+	BB+	BB+	BB+	BB+
55	Outlook	Stable	Stable	Stable	Stable	Stable	Stable

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-33 (MRB-9)
Page: 1 of 6
Witness: MRBleckman
Date: June 2026

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	01/02/24	DUK	Duke Energy Corp	Unsecured	550	4.850%	Baa2	BBB	1/5/2027	+75
2	01/02/24	DUK	Duke Energy Corp	Unsecured	550	4.850%	Baa2	BBB	1/5/2029	+95
3	01/02/24	D	Virginia Electric and Power Co	Unsecured	500	5.000%	A2	BBB+	01/15/34	+115
4	01/02/24	D	Virginia Electric and Power Co	Unsecured	500	5.350%	A2	BBB+	01/15/54	+127
5	01/02/24	PPL	PPL Electric Utilities Corp	Secured	650	4.850%	A1	A+	02/15/34	+92
6	**01/02/24**	**CMS**	**Consumers Energy Co**	**Secured**	**600**	**4.600%**	**A1**	**A**	**05/30/29**	**+73**
7	01/03/24	BRKHEC	PacifiCorp	Secured	500	5.100%	A2	A	02/15/29	+120
8	01/03/24	BRKHEC	PacifiCorp	Secured	700	5.300%	A2	A	02/15/31	+140
9	01/03/24	BRKHEC	PacifiCorp	Secured	1,100	5.450%	A2	A	02/15/34	+155
10	01/03/24	BRKHEC	PacifiCorp	Secured	1,500	5.800%	A2	A	01/15/55	+175
11	01/03/24	DUK	Duke Energy Carolinas LLC	Secured	575	4.850%	Aa3	A	01/15/34	+100
12	01/03/24	DUK	Duke Energy Carolinas LLC (Reopening)	Secured	425	5.400%	Aa3	A	01/15/54	+118
13	01/03/24	AEE	Union Electric Co	Secured	350	5.250%	A2	A	01/15/54	+123
14	01/04/24	WTRG	Essential Utilities Inc	Unsecured	500	5.375%	Baa2	A-	01/15/34	+140
15	01/08/24	EIX	Southern California Edison Co	Secured	500	4.875%	A2	A-	02/01/27	+75
16	01/08/24	EIX	Southern California Edison Co	Secured	900	5.200%	A2	A-	06/01/34	+120
17	01/08/24	NGGLN	National Grid PLC	Unsecured	750	5.418%	Baa2	BBB	01/11/34	+142
18	01/09/24	AQNCN	Liberty Utilities Co	Unsecured	500	5.577%	Baa2	BBB	01/31/29	+160
19	01/09/24	AQNCN	Liberty Utilities Co	Unsecured	350	5.869%	Baa2	BBB	01/31/34	+185
20	01/11/24	NGGLN	Niagara Mohawk Power	Unsecured	500	5.290%	Baa1	BBB+	01/17/34	+130
21	01/11/24	NGGLN	Niagara Mohawk Power	Unsecured	700	5.664%	Baa1	BBB+	01/17/54	+145
22	01/16/24	ES	Eversource Energy	Unsecured	350	5.000%	Baa2	BBB+	1/1/2027	+100
23	01/16/24	ES	Eversource Energy	Unsecured	650	5.500%	Baa2	BBB+	1/1/2034	+150
24	01/16/24	ES	Connecticut Light and Power Co	Secured	350	4.650%	A1	A+	1/1/2029	+75
25	01/22/24	BRKHEC	MidAmerican Energy	Secured	600	5.300%	Aa2	A	02/01/55	+98
26	01/25/24	TE	Tampa Electric	Unsecured	500	4.900%	A3	BBB+	03/01/29	+88
27	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	600	FRN	Baa1	BBB+	01/29/26	+76
28	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	1,000	4.950%	Baa1	BBB+	01/29/26	+65
29	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	900	4.900%	Baa1	BBB+	03/15/29	+95
30	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	1,100	5.250%	Baa1	BBB+	03/15/34	+120
31	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	800	5.550%	Baa1	BBB+	03/15/54	+125
32	01/29/24	BRKHEC	Northern Natural Gas Co	Unsecured	500	5.625%	A2	A-	02/01/54	+127
33	02/06/24	SR	Spire Inc	Unsecured	350	5.300%	Baa2	BBB+	03/01/26	+85
34	02/12/24	DTE	DTE Energy Co	Unsecured	1,200	5.100%	Baa2	BBB	03/01/29	+103
35	02/20/24	AWK	American Water Capital Corp	Unsecured	700	5.150%	Baa1	A	03/01/34	+92
36	02/20/24	AWK	American Water Capital Corp	Unsecured	700	5.450%	Baa1	A	03/01/54	+107
37	02/20/24	SO	Georgia Power Co	Unsecured	500	5.004%	Baa1	BBB+	02/23/27	+62
38	02/20/24	SO	Georgia Power Co	Unsecured	900	5.250%	Baa1	BBB+	03/15/34	+102
39	02/20/24	DTE	DTE Electric Co	Secured	500	4.850%	Aa3	A	12/01/26	+47
40	02/20/24	DTE	DTE Electric Co	Secured	500	5.200%	Aa3	A	03/01/34	+93
41	02/21/24	NGGLN	Massachusetts Electric Co	Unsecured	400	5.867%	Baa1	BBB+	02/26/54	+138
42	02/22/24	EXC	Exelon Corp	Unsecured	650	5.150%	Baa2	BBB	03/15/29	+88
43	02/22/24	EXC	Exelon Corp	Unsecured	650	5.450%	Baa2	BBB	03/15/34	+115
44	02/22/24	EXC	Exelon Corp (Reopening)	Unsecured	400	5.600%	Baa2	BBB	03/15/53	+130
45	02/22/24	XEL	Northern States Power Co/MN	Secured	700	5.400%	Aa3	A+	03/15/54	+97
46	02/26/24	PCG	Pacific Gas and Electric Co	Secured	850	5.550%	Baa2	BBB	05/15/29	+125
47	02/26/24	PCG	Pacific Gas and Electric Co	Secured	1,100	5.800%	Baa2	BBB	05/15/34	+153
48	02/26/24	PCG	Pacific Gas and Electric Co (Reopening)	Secured	300	6.750%	Baa2	BBB	01/15/53	+170
49	02/26/24	SO	The Southern Co (Reopening)	Unsecured	400	5.500%	Baa2	BBB	03/15/29	+85
50	02/26/24	SO	The Southern Co (Reopening)	Unsecured	400	5.700%	Baa2	BBB	03/15/34	+117
51	02/26/24	XEL	Xcel Energy Inc	Unsecured	800	5.500%	Baa1	BBB+	03/15/34	+125
52	02/26/24	EXC	Potomac Electric Power Co	Secured	375	5.200%	A2	A	03/15/34	+95
53	02/26/24	EXC	Potomac Electric Power Co	Secured	300	5.500%	A2	A	03/15/54	+110
54	02/26/24	CNP	CenterPoint Energy Houston Electric LLC	Secured	400	5.150%	A2	A	03/01/34	+90
55	02/26/24	DUK	Duke Energy Indiana LLC	Secured	300	5.250%	Aa3	A	03/01/34	+100
56	02/27/24	EIX	Southern California Edison Co	Secured	600	5.350%	A2	A-	03/01/26	+62
57	02/27/24	EIX	Southern California Edison Co	Secured	600	5.150%	A2	A-	06/01/29	+83
58	02/27/24	EIX	Southern California Edison Co	Secured	400	5.750%	A2	A-	04/15/54	+135
59	02/27/24	NEE	NextEra Energy Capital Holdings Inc	Pref/Hybrid	1,000	6.700%	Baa2	BBB	09/01/54	+242
60	02/28/24	PEG	Public Service Electric and Gas Co	Secured	450	5.200%	A1	A	03/01/34	+93
61	02/28/24	PEG	Public Service Electric and Gas Co	Secured	550	5.450%	A1	A	03/01/54	+108
62	03/04/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	1,000	4.850%	Baa1	BBB+	04/30/31	+142
63	03/04/24	ETR	Entergy Louisiana LLC	Secured	500	5.350%	A2	A	03/15/34	+115
64	03/04/24	ETR	Entergy Louisiana LLC	Secured	700	5.700%	A2	A	03/15/54	+135
65	03/04/24	LNT	Wisconsin Power and Light Co	Unsecured	300	5.375%	Baa1	A	03/30/34	+118
66	03/06/24	AES	AES Andes SA	Unsecured	500	6.300%	Baa3	BBB-	03/15/29	+220
67	03/07/24	AES	Indianapolis Power & Light Co	Secured	650	5.700%	A2	A-	04/01/54	+147
68	03/08/24	AES	IPALCO Enterprises Inc	Secured	400	5.750%	Baa3	BBB-	04/01/34	+170
69	03/11/24	NI	NiSource Inc	Unsecured	650	5.350%	Baa2	BBB+	04/01/34	+128
70	03/11/24	SRE	Sempra Energy	Pref/Hybrid	600	6.875%	Baa3	BBB-	10/01/54	+279
71	03/11/24	DUK	Duke Energy Progress LLC	Secured	500	5.100%	Aa3	A	03/15/34	+103
72	03/11/24	AEP	AEP Transmission Co LLC	Unsecured	450	5.150%	A2	BBB+	04/01/34	+105
73	03/11/24	DUK	Duke Energy Ohio Inc	Secured	425	5.550%	A2	A	03/15/54	+130
74	03/12/24	CEG	Constellation Energy Generation LLC	Unsecured	900	5.750%	Baa2	BBB+	03/15/54	+145
75	03/12/24	SRE	Southern California Gas Co	Secured	500	5.600%	Aa3	A+	04/01/54	+133
76	03/18/24	SRE	San Diego Gas & Electric Co	Secured	600	5.550%	A1	A	04/15/54	+115
77	03/18/24	AEP	Appalachian Power Co	Unsecured	400	5.650%	Baa1	BBB+	04/01/34	+135
78	03/19/24	ES	Public Service Co of New Hampshire (Reopening)	Secured	300	5.350%	A1	A+	10/01/33	+95
79	03/21/24	PPL	The Narragansett Electric Co	Unsecured	500	5.350%	A3	A-	05/01/34	+108
80	03/25/24	PEG	Public Service Enterprise Group Inc	Unsecured	750	5.200%	Baa2	BBB	04/01/29	+100
81	03/25/24	PEG	Public Service Enterprise Group Inc	Unsecured	500	5.450%	Baa2	BBB	04/01/34	+122
82	03/25/24	AEE	Union Electric Company d/b/a Ameren Missouri	Secured	500	5.200%	A2	A	04/01/34	+98
83	04/01/24	XEL	Public Service Co of Colorado	Secured	450	5.350%	A1	A	05/15/34	+105
84	04/01/24	XEL	Public Service Co of Colorado	Secured	750	5.750%	A1	A	05/15/54	+130
85	04/01/24	EVRG	Evergy Metro Inc	Secured	300	5.400%	A2	A	04/01/34	+110
86	04/03/24	ENGIFP	Engie SA	Unsecured	750	5.250%	Baa1	BBB+	04/10/29	+100
87	04/03/24	ENGIFP	Engie SA	Unsecured	750	5.625%	Baa1	BBB+	04/10/34	+128
88	04/03/24	ENGIFP	Engie SA	Unsecured	500	5.875%	Baa1	BBB+	04/10/54	+148
89	04/09/24	DUK	Duke Energy Corporation	Unsecured	750	3.750%	Baa2	BBB	04/01/31	MS+120
90	04/09/24	VST	Vistra Operations Co LLC	Secured	500	6.000%	Baa3	BBB-	04/15/34	+165
91	04/11/24	RWE	RWE Finance US LLC	Unsecured	1,000	5.875%	Baa2	NR	04/16/34	+135
92	04/11/24	RWE	RWE Finance US LLC	Unsecured	1,000	6.250%	Baa2	NR	04/16/54	+160
93	04/15/24	EDF	Electricite de France SA	Unsecured	650	5.650%	Baa1	BBB	04/22/29	+105
94	04/15/24	EDF	Electricite de France SA	Unsecured	650	5.950%	Baa1	BBB	04/22/34	+135
95	04/15/24	EDF	Electricite de France SA	Unsecured	750	6.000%	Baa1	BBB	04/22/64	+185
96	04/15/24	ES	Eversource Energy	Unsecured	700	5.850%	Baa2	BBB+	04/15/31	+120
97	04/15/24	ES	Eversource Energy	Unsecured	700	5.950%	Baa2	BBB+	07/15/34	+135
98	04/29/24	DTE	DTE Energy Co	Unsecured	850	5.850%	Baa2	BBB	06/01/34	+125
99	05/02/24	AEP	Ohio Power Co	Unsecured	350	5.650%	Baa1	BBB+	06/01/34	+110
100	05/06/24	D	Dominion Energy Inc	Pref/Hybrid	1,000	6.875%	Baa3	BBB-	02/01/55	+239
101										

102 FRN: Floating Rate Note

103 MS: Mid-Swap - The average of the bid and offer swap rates for a reference maturity

104 SOFR: Secured Overnight Financing Rate

105 Source: Barclays Bank

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-33 (MRB-9)
Page: 2 of 6
Witness: MRBleckman
Date: June 2026

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	05/06/24	D	Dominion Energy Inc	Pref/Hybrid	1,000	7.000%	Baa3	BBB-	06/01/54	+251
2	05/06/24	ED	Consolidated Edison Co of New York Inc	Unsecured	400	5.375%	A3	A-	05/15/34	+90
3	05/06/24	ED	Consolidated Edison Co of New York Inc	Unsecured	1,000	5.700%	A3	A-	05/15/54	+110
4	05/06/24	EXC	Commonwealth Edison Co	Secured	400	5.300%	A1	A	06/01/34	+85
5	05/06/24	EXC	Commonwealth Edison Co	Secured	400	5.650%	A1	A	06/01/54	+105
6	05/06/24	EIX	Southern California Edison Co	Secured	750	5.450%	A2	A-	06/01/31	+97
7	05/06/24	PNW	Arizona Public Service Co	Unsecured	450	5.700%	Baa1	BBB+	08/15/34	+125
8	05/06/24	ITC	ITC Holdings Corp	Unsecured	400	5.650%	Baa2	BBB+	05/09/34	+118
9	05/06/24	OGE	OGE Energy Corp	Unsecured	350	5.450%	Baa1	BBB	05/15/29	+100
10	05/07/24	EIX	SCE Trust VIII ($25 par)	Pref/Hybrid	350	6.950%	Baa3	BB+	05/13/29	+248
11	05/07/24	ETR	Entergy Arkansas LLC	Secured	400	5.450%	A2	A	06/01/34	+100
12	05/07/24	ETR	Entergy Arkansas LLC	Secured	400	5.750%	A2	A	06/01/54	+118
13	05/07/24	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	450	5.100%	A2	A-	05/06/27	+48
14	05/07/24	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	350	5.150%	A2	A-	06/15/29	+73
15	05/07/24	WEC	Wisconsin Electric Power Co	Unsecured	350	5.000%	A2	A-	05/15/29	+60
16	05/08/24	CNP	CenterPoint Energy Inc	Unsecured	700	5.400%	Baa2	BBB	06/01/29	+95
17	05/13/24	NI	NiSource	Pref/Hybrid	500	6.950%	Baa3	BBB-	11/30/54	+245
18	05/13/24	BKH	Black Hills Corporation	Unsecured	450	6.000%	Baa2	BBB+	01/15/35	+155
19	05/13/24	XEL	Northern States Power - WI	Secured	400	5.650%	Aa3	A	06/15/54	+105
20	05/13/24	ETR	Entergy Mississippi	Secured	300	5.850%	A2	A	06/01/54	+123
21	05/15/24	ONCRTX	Oncor Electric Delivery Company	Secured	500	3.500%	A2	A+	05/15/31	MS+80
22	05/16/24	AES	The AES Corp	Pref/Hybrid	950	7.600%	Ba1	BB	01/15/55	+320
23	05/20/24	ETR	Entergy Corp	Pref/Hybrid	1,200	7.125%	Baa3	BBB-	12/01/54	+267
24	05/20/24	AEP	AEP Texas Inc	Unsecured	500	5.450%	Baa2	BBB+	05/15/29	+100
25	05/20/24	AEP	AEP Texas Inc	Unsecured	350	5.700%	Baa2	BBB+	05/15/34	+130
26	05/20/24	ES	NSTAR Electric Co	Unsecured	600	5.400%	A2	A	06/01/34	+98
27	05/21/24	EVRG	Evergy Missouri West Inc	Secured	300	5.650%	A3	A	06/01/34	+125
28	05/28/24	NEE	Florida Power & Light Co	Secured	750	5.150%	Aa2	A+	06/15/29	+60
29	05/28/24	NEE	Florida Power & Light Co	Secured	750	5.300%	Aa2	A+	06/15/34	+80
30	05/28/24	NEE	Florida Power & Light Co	Secured	850	5.600%	Aa2	A+	06/15/54	+95
31	05/28/24	SRE	Sempra Energy (Reopening)	Pref/Hybrid	500	6.875%	Baa3	BBB-	10/01/54	+279
32	06/03/24	EXC	Baltimore Gas and Electric Co	Unsecured	400	5.300%	A3	A	06/01/34	+93
33	06/03/24	EXC	Baltimore Gas and Electric Co	Unsecured	400	5.650%	A3	A	06/01/54	+110
34	06/03/24	XEL	Southwestern Public Service Co	Secured	600	6.000%	A3	A-	06/01/54	+150
35	06/03/24	LNT	Alliant Energy Finance LLC	Unsecured	375	5.400%	Baa2	BBB+	06/06/27	+80
36	06/04/24	PSD	Puget Sound Energy Inc	Unsecured	400	5.330%	A2	A-	06/15/34	+100
37	06/04/24	PSD	Puget Sound Energy Inc	Unsecured	400	5.685%	A2	A-	06/15/54	+120
38	06/05/24	NEE	NextEra Energy Capital Holdings Inc	Pref/Hybrid	1,200	6.750%	Baa2	BBB	06/15/54	+246
39	06/05/24	DUK	Duke Energy Corp	Unsecured	750	5.450%	Baa2	BBB	06/15/34	+118
40	06/05/24	DUK	Duke Energy Corp	Unsecured	750	5.800%	Baa2	BBB	06/15/54	+140
41	06/05/24	AES	AES Andes SA	Pref/Hybrid	530	8.150%	Ba1	BB	06/10/55	+384
42	06/10/24	EMACN	EUSHI Finance Inc	Pref/Hybrid	500	7.625%	Ba1	BB+	12/15/54	+314
43	06/05/24	PNW	Pinnacle West Capital Corp	Unsecured	350	FRN	Baa2	BBB	06/10/26	+82
44	06/17/24	AEP	American Electric Power Co.	Pref/Hybrid	400	7.050%	Baa3	BBB-	12/15/54	+275
45	06/17/24	AEP	American Electric Power Co.	Pref/Hybrid	600	6.950%	Baa3	BBB-	12/15/54	+268
46	06/17/24	ONCRTX	Oncor Electric Delivery	Secured	750	5.550%	A2	A+	06/15/54	+115
47	06/17/24	AEE	Ameren Illinois Company	Secured	625	5.550%	A1	A	07/01/54	+115
48	06/17/24	NI	NiSource Inc	Unsecured	600	5.200%	Baa2	BBB+	07/01/29	+95
49	06/17/24	CNP	CenterPoint Energy Resources Corp	Unsecured	400	5.400%	A3	BBB+	07/01/34	+115
50	06/24/24	HASI	Hannon Armstrong Sustainable Infrastructure Capital In	Unsecured	700	6.375%	Baa3	BB+	07/01/34	+225
51	06/25/24	EIX	Edison International	Unsecured	500	5.450%	Baa2	BBB-	06/15/29	+120
52	07/15/24	NGGLN	The Brooklyn Union Gas Co (Reopening)	Unsecured	150	6.388%	Baa2	BBB+	09/15/33	+167
53	07/15/24	NGGLN	The Brooklyn Union Gas Co	Unsecured	450	6.415%	Baa2	BBB+	07/18/54	+195
54	**07/29/24**	**CMS**	**Consumers Energy Co**	**Secured**	**700**	**4.700%**	**A1**	**A**	**01/15/30**	**+68**
55	07/29/24	DTE	DTE Energy Co	Unsecured	1,200	4.950%	Baa2	BBB	7/1/2027	+80
56	08/01/24	PEG	Public Service Electric & Gas	Secured	600	4.850%	A1	A	8/1/2034	+90
57	08/01/24	PEG	Public Service Electric & Gas	Secured	500	5.300%	A1	A	8/1/2054	+105
58	08/01/24	AGR	New York State Electric & Gas Corp	Unsecured	525	5.300%	Baa1	A-	8/15/2034	+135
59	08/06/24	ETR	Entergy Louisiana LLC	Secured	700	5.150%	A2	A	09/15/34	+130
60	08/06/24	PPL	PPL Capital Funding Inc	Unsecured	750	5.250%	Baa1	BBB+	09/01/34	+143
61	08/06/24	SR	Spire Missouri Inc	Secured	320	5.150%	A1	A	08/15/34	+130
62	08/06/24	ES	The Connecticut Light and Power Co	Secured	300	4.950%	A1	A+	08/15/34	+110
63	08/06/24	D	Virginia Electric and Power Co	Unsecured	600	5.050%	A2	BBB+	08/15/34	+120
64	08/06/24	D	Virginia Electric and Power Co	Unsecured	600	5.550%	A2	BBB+	08/15/54	+140
65	08/07/24	IDA	Idaho Power Co	Secured	300	5.200%	A2	A-	08/15/34	+125
66	08/07/24	FTSCN	Tucson Electric Power Co	Unsecured	400	5.200%	A3	A-	09/15/34	+128
67	08/08/24	WTRG	Essential Utilities Inc	Unsecured	500	4.800%	Baa2	BBB+	08/15/27	+90
68	08/08/24	NRUC	National Rural Utilities Cooperative Finance Corp	Secured	350	5.000%	A1	A-	08/15/34	+110
69	08/08/24	OGS	One Gas Inc (Reopening)	Unsecured	250	5.100%	Aaa	AA+	04/01/29	+85
70	08/08/24	SRE	Southern California Gas Co	Secured	600	5.050%	Aa3	A+	09/01/34	+110
71	08/08/24	TVA	Tennessee Valley Authority	Unsecured	1,000	4.375%	Aaa	AA+	08/01/34	+48
72	08/12/24	DUK	Piedmont Natural Gas Co Inc	Secured	375	5.100%	A3	BBB+	02/15/35	+120
73	08/12/24	CNP	CenterPoint Energy	Pref/Hybrid	400	7.000%	Baa3	BBB-	02/15/55	+325
74	08/12/24	CNP	CenterPoint Energy	Pref/Hybrid	400	6.850%	Baa3	BBB-	02/15/55	+295
75	08/12/24	ETR	Entergy Texas Inc	Secured	350	5.550%	A3	A	09/15/54	+140
76	08/12/24	OGE	Oklahoma Gas and Electric Co (Reopening)	Secured	350	5.600%	A3	A-	04/01/53	+130
77	08/19/24	DUK	Duke Energy Corp	Pref/Hybrid	1,000	6.450%	Baa3	BBB-	09/01/54	+259
78	09/03/24	FE	FirstEnergy Transmission LLC	Unsecured	400	4.550%	Baa2	BBB+	01/15/30	+92
79	09/03/24	FE	FirstEnergy Transmission LLC	Unsecured	400	5.000%	Baa2	BBB+	01/15/35	+117
80	09/03/24	NI	NiSource Inc.	Pref/Hybrid	500	6.375%	Baa3	BBB-	03/31/55	+253
81	09/03/24	PCG	Pacific Gas and Electric Co	Secured	750	5.900%	Baa2	BBB	10/01/54	+180
82	09/03/24	PCG	Pacific Gas and Electric Co	Secured	1,000	FRN	Baa2	BBB	09/04/25	+95
83	09/03/24	EXC	PECO Energy Co	Secured	575	5.250%	Aa3	A	09/15/54	+112
84	09/03/24	EIX	Southern California Edison Co	Secured	500	4.400%	A2	A-	09/06/26	+55
85	09/03/24	SO	Southern Company Gas Capital Corp	Unsecured	450	4.950%	Baa1	A-	09/15/34	+115
86	09/04/24	LNT	Inerstate Power and Light	Unsecured	350	4.950%	Baa1	A-	09/30/34	+120
87	09/04/24	LNT	Inerstate Power and Light	Unsecured	300	5.450%	Baa1	A-	09/30/54	+140
88	09/04/24	SRE	Sempra	Pref/Hybrid	1,250	6.400%	Baa3	BBB-	10/01/54	+263
89	09/04/24	SO	The Southern Co	Unsecured	750	4.850%	Baa2	BBB+	03/15/35	+110
90	09/09/24	NRUC	National Rural Utilities	Unsecured	300	FRN	A2	A-	09/16/27	+100
91	09/09/24	NRUC	National Rural Utilities	Unsecured	550	4.120%	A2	A-	09/16/27	+58
92	09/09/24	NRUC	National Rural Utilities	Unsecured	500	5.150%	A2	A-	06/15/29	+73
93	09/09/24	PCG	PG&E Corporation	Pref/Hybrid	1,000	7.375%	Ba3	B	03/15/55	+388
94	09/09/24	WEC	Wisconsin Electric Power Co	Unsecured	300	4.600%	A2	A-	10/01/34	+90
95	09/09/24	WEC	Wisconsin Electric Power Co	Unsecured	300	5.050%	A2	A-	10/01/54	+108
96	09/16/24	ALACN	AltaGas Ltd	Pref/Hybrid	900	7.200%	NR	BB	10/15/54	+357
97	09/17/24	ATO	Atmos Energy Corp	Unsecured	650	5.000%	A1	A-	12/15/54	+108
98	09/26/24	NIAENE	Niagara Energy SAC	Unsecured	1,200	5.746%	Baa3	BBB-	10/03/34	+195
99	09/30/24	AEE	Union Electric Company d/b/a Ameren Missouri	Secured	450	5.125%	A2	A	03/15/55	+102
100	10/07/24	BRKHEC	Eastern Energy Gas Holdings	Unsecured	900	5.650%	Baa1	A-	10/15/54	+135

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-33 (MRB-9)
Page: 3 of 6
Witness: MRBleckman
Date: June 2026

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	10/29/24	CNP	CenterPoint Energy Inc	Pref/Hybrid	500	6.700%	Baa3	BBB-	05/15/55	+259
2	10/31/24	EIX	Edison International	Unsecured	550	5.250%	Baa2	BBB-	03/15/32	+105
3	11/08/24	ONCRTX	Oncor Electric Delivery	Secured	550	4.650%	A2	A+	11/01/29	+52
4	11/13/24	PCG	PG&E Corporation (Reopening)	Pref/Hybrid	500	7.375%	Ba3	BBB-	03/15/55	+388
5	11/14/24	ED	Consolidated Edison Co of New York	Unsecured	350	FRN	A3	A-	11/18/27	+52
6	11/14/24	ED	Consolidated Edison Co of New York	Unsecured	450	5.125%	A3	A-	03/15/35	+70
7	11/14/24	ED	Consolidated Edison Co of New York	Unsecured	650	5.500%	A3	A-	03/15/55	+70
8	11/14/24	D	Dominion Energy	Pref/Hybrid	1,250	6.625%	Baa3	BBB-	05/15/55	+221
9	11/18/24	SRE	Sempra	Pref/Hybrid	400	6.625%	Baa3	BBB-	04/01/55	+235
10	11/18/24	SRE	Sempra	Pref/Hybrid	600	6.550%	Baa3	BBB-	04/01/55	+214
11	11/19/24	VST	Vistra Operations Co	Secured	500	5.050%	Baa3	BBB-	12/30/26	+80
12	11/19/24	VST	Vistra Operations Co	Secured	750	5.700%	Baa3	BBB-	12/30/34	+133
13	11/21/24	BIP	Brookfield Infrastructure Finance ULC	Pref/Hybrid	300	6.750%	NR	BBB-	03/15/55	+245
14	12/02/24	EVRG	Evergy Inc.	Pref/Hybrid	500	6.650%	Baa3	BBB-	06/01/55	+256
15	12/02/24	FE	Jersey Central Power & Light Co	Unsecured	700	5.100%	A3	BBB	01/15/35	+95
16	12/02/24	SO	Georgia Power Co	Unsecured	600	4.550%	A3	A	03/15/30	+52
17	12/02/24	WEC	Wisconsin Public Service	Unsecured	300	4.550%	A2	A-	12/01/29	+48
18	12/03/24	AEP	Public Service Co of Oklahoma	Unsecured	600	5.200%	Baa1	BBB+	01/15/35	+100
19	12/03/24	ETR	System Energy Resources Inc	Secured	300	5.300%	Baa2	BBB+	12/15/34	+113
20	12/04/24	AES	The AES Corporation	Pref/Hybrid	500	6.950%	Ba1	BB	07/15/55	+289
21	12/09/24	HASI	Hannon Armstrong Sustainable Infrastructure Capital In	Unsecured	300	6.375%	Baa3	BB+	07/01/34	+220
22	01/02/25	D	Dominon Energy South Carolina	Secured	450	5.300%	A2	A	01/15/35	+75
23	01/02/25	DUK	Duke Energy Carolinas	Secured	400	4.850%	Aa3	A	03/15/30	+50
24	01/02/25	DUK	Duke Energy Carolinas	Secured	700	5.250%	Aa3	A	03/15/35	+72
25	01/02/25	ETR	Entergy Louisiana	Secured	750	5.800%	A2	A	03/15/35	+103
26	01/06/25	EIX	Southern California Edison Company	Secured	850	5.450%	A2	A-	03/01/35	+85
27	01/06/25	EIX	Southern California Edison Company	Secured	650	5.900%	A2	A-	03/01/55	+108
28	01/06/25	ES	Connecticut Light & Power Company	Secured	400	4.950%	A1	A	01/15/30	+55
29	01/07/25	NGGLN	Boston Gas Company	Unsecured	500	5.843%	Baa1	BBB+	01/10/35	+115
30	01/08/25	SO	Southern Company ($25 par)	Pref/Hybrid	565	6.500%	Baa2	BBB	03/15/85	-
31	01/13/25	BRKHEC	Eastern Energy Gas Holdings	Unsecured	700	5.800%	Baa1	A-	01/15/35	+105
32	01/13/25	BRKHEC	Eastern Energy Gas Holdings	Unsecured	500	6.200%	Baa1	A-	01/15/55	+125
33	01/27/25	KALLPA	Kallpa Generacion SA	Unsecured	500	5.875%	Baa3	NR	01/30/32	+163
34	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	500	FRN	Baa1	BBB+	02/04/28	+80
35	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	1,000	4.850%	Baa1	BBB+	02/04/28	+60
36	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	1,000	5.050%	Baa1	BBB+	03/15/30	+73
37	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	750	5.300%	Baa1	BBB+	03/15/32	+88
38	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	1,000	5.450%	Baa1	BBB+	03/15/35	+98
39	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	750	5.900%	Baa1	BBB+	03/15/55	+113
40	01/30/25	BRKHEC	Nevada Power Company	Pref/Hybrid	300	6.250%	Baa2	BBB-	05/15/55	+194
41	02/04/25	NEE	NextEra Energy Capital Holdings Inc.	Pref/Hybrid	1,500	6.375%	Baa2	BBB	08/15/55	+205
42	02/04/25	NEE	NextEra Energy Capital Holdings Inc.	Pref/Hybrid	1,000	6.500%	Baa2	BBB	08/15/55	+198
43	02/05/25	NFG	National Fuel Gas Co	Unsecured	500	5.500%	Baa3	BBB-	03/15/30	+118
44	02/05/25	NFG	National Fuel Gas Co	Unsecured	500	5.950%	Baa3	BBB-	03/15/35	+147
45	02/05/25	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	600	4.750%	A2	A-	02/07/28	+52
46	02/05/25	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	500	4.950%	A2	A-	02/07/30	+67
47	02/13/25	EXC	Exelon Corporation	Pref/Hybrid	1,000	6.500%	Baa3	BBB	03/15/55	+198
48	02/18/25	CMS	CMS Energy Corporation	Pref/Hybrid	1,000	6.500%	Baa3	BBB-	06/01/55	+196
49	02/18/25	EXC	Exelon Corporation	Unsecured	500	5.125%	Baa2	BBB+	03/15/31	+75
50	02/18/25	EXC	Exelon Corporation	Unsecured	500	5.875%	Baa2	BBB+	03/15/55	+113
51	02/18/25	NEE	Florida Power and Light (Reopening)	Secured	350	5.300%	Aa2	A+	06/15/34	+73
52	02/18/25	NEE	Florida Power and Light	Secured	950	5.700%	Aa2	A+	03/15/55	+93
53	02/18/25	NEE	Florida Power and Light	Secured	700	5.800%	Aa2	A+	03/15/65	+103
54	02/18/25	FTSCN	Tucson Electric Power	Unsecured	300	5.900%	A3	A-	04/15/55	+115
55	02/18/25	DTE	DTE Energy	Unsecured	1,100	5.200%	Baa2	BBB	04/01/30	+85
56	02/24/25	SO	Georgia Power Company	Unsecured	400	FRN	A3	A	09/15/26	+28
57	02/24/25	SO	Georgia Power Company	Unsecured	500	4.850%	A3	A	03/15/31	+65
58	02/24/25	SO	Georgia Power Company	Unsecured	700	5.200%	A3	A	03/15/35	+83
59	02/24/25	PCG	Pacific Gas & Electric	Secured	1,000	5.700%	Baa2	BBB	03/01/35	+130
60	02/24/25	PCG	Pacific Gas & Electric	Secured	750	6.150%	Baa2	BBB	03/01/55	+150
61	02/24/25	ES	NSTAR Electric	Unsecured	400	4.850%	A2	A-	03/01/30	+65
62	02/24/25	ES	NSTAR Electric	Unsecured	400	5.200%	A2	A-	03/01/35	+85
63	02/24/25	AWK	American Water Company	Unsecured	800	5.250%	Baa1	A	03/01/35	+90
64	02/24/25	CNP	CenterPoint Energy Houston Electric	Secured	500	4.800%	A2	A	03/15/30	+60
65	02/24/25	ETR	Entergy Texas	Secured	500	5.250%	A3	A	04/15/35	+88
66	02/24/25	AEE	Ameren Illinois	Secured	350	5.625%	A1	A	03/01/55	+95
67	02/25/25	SO	Southern Company	Pref/Hybrid	1,800	6.375%	Baa2	BBB	03/15/55	+207
68	02/27/25	PEG	Public Service Electric Gas & Co	Secured	400	5.050%	A1	A	03/01/35	+78
69	02/27/25	PEG	Public Service Electric Gas & Co	Secured	500	5.500%	A1	A	03/01/55	+98
70	02/27/25	AEE	Ameren Corporation	Unsecured	750	5.375%	Baa1	BBB	03/15/35	+110
71	03/03/25	DUK	Duke Energy Progress	Secured	500	4.350%	Aa3	A	03/06/27	+40
72	03/03/25	DUK	Duke Energy Progress	Secured	850	5.050%	Aa3	A	03/15/35	+90
73	03/03/25	DUK	Duke Energy Progress	Secured	750	5.550%	Aa3	A	03/15/55	+110
74	03/03/25	TE	Tampa Electric	Unsecured	600	5.150%	A3	BBB+	03/01/35	+100
75	03/06/25	PEG	Public Service Enterprise Group	Unsecured	600	4.900%	Baa2	BBB	03/15/30	+115
76	03/06/25	PEG	Public Service Enterprise Group	Unsecured	400	5.400%	Baa2	BBB	03/15/35	+140
77	03/06/25	EVRG	Evergy Kansas Central	Secured	300	4.700%	Baa1	BBB+	03/15/28	+73
78	03/06/25	EVRG	Evergy Kansas Central	Secured	300	5.250%	Baa1	BBB+	03/15/35	+100
79	03/06/25	D	Dominion Energy	Unsecured	800	5.000%	Baa2	BBB	06/15/30	+95
80	03/06/25	D	Dominion Energy	Unsecured	700	5.450%	Baa2	BBB	03/15/35	+120
81	03/10/25	PSD	Puget Energy Inc.	Secured	600	5.725%	Baa3	BBB-	03/15/35	+150
82	03/10/25	ETR	Entergy Mississippi	Secured	600	5.800%	A2	A	04/15/55	+125
83	03/10/25	IDA	Idaho Power Co	Secured	400	5.700%	A2	A-	03/15/55	+120
84	03/11/25	EIX	Edison International	Unsecured	550	6.250%	Baa2	BBB-	03/15/30	+250
85	03/11/25	AES	AES Andes SA	Unsecured	400	6.250%	Baa3	BBB-	03/14/32	+210
86	03/12/25	EIX	Southern California Edison Co	Secured	650	5.250%	A2	A-	03/15/30	+118
87	03/12/25	EIX	Southern California Edison Co	Secured	850	6.200%	A2	A-	09/15/55	+160
88	03/12/25	AES	AES Corp	Unsecured	800	5.800%	Baa3	BBB-	03/15/32	+160
89	03/12/25	NWN	Northwest Natural Holding Co	Pref/Hybrid	325	7.000%	NR	BBB	09/15/55	+270
90	03/17/25	XEL	Public Service Co of Colorado (reopening)	Secured	400	5.350%	A1	A	05/15/34	+108
91	03/17/25	XEL	Public Service Co of Colorado	Secured	600	5.850%	A1	A	05/15/55	+125
92	03/17/25	ONCRTX	Oncor Electric Delivery	Secured	500	4.500%	A2	A+	03/20/27	+45
93	03/17/25	ONCRTX	Oncor Electric Delivery	Secured	650	5.350%	A2	A+	04/01/35	+105
94	03/17/25	ONCRTX	Oncor Electric Delivery	Secured	650	5.800%	A2	A+	04/01/55	+120
95	03/18/25	BRKHEC	PacifiCorp	Pref/Hybrid	850	7.375%	Baa2	BBB-	09/15/55	+332
96	03/18/25	XEL	Xcel Energy	Unsecured	350	4.750%	Baa1	BBB	03/15/28	+85
97	03/18/25	XEL	Xcel Energy	Unsecured	750	5.600%	Baa1	BBB	02/15/35	+135
98	03/20/25	NI	NiSource Inc.	Unsecured	750	5.850%	Baa2	BBB+	04/01/55	+130
99	03/20/25	SO	Alabama Power Company	Unsecured	500	5.100%	A1	A	04/02/35	+88
100	03/24/25	OGE	Oklahoma Gas & Electric	Unsecured	350	5.800%	A3	A-	04/01/55	+118

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-33 (MRB-9)
Page: 4 of 6
Witness: MRBleckman
Date: June 2026

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	03/24/25	SRE	San Diego Gas & Electric	Secured	850	5.400%	A1	A	04/15/35	+110
2	03/26/25	AEE	Union Electric Company	Secured	500	5.250%	A2	A	04/15/35	+92
3	04/14/25	FE	Trans-Allegheny Interstate Line Co	Unsecured	600	5.000%	A3	A-	01/15/31	+100
4	**04/28/25**	**CMS**	**Consumers Energy Co**	**Secured**	**500**	**4.500%**	**A1**	**A**	**01/15/31**	**+67**
5	**04/28/25**	**CMS**	**Consumers Energy Co**	**Secured**	**625**	**5.050%**	**A1**	**A**	**05/15/35**	**+87**
6	04/28/25	XEL	Northern States Power - MN	Secured	600	5.050%	Aa3	A	05/15/35	+83
7	04/28/25	XEL	Northern States Power - MN	Secured	500	5.650%	Aa3	A	05/15/55	+98
8	04/29/25	XEL	Southwestern Public Service Co	Secured	500	5.300%	A3	A-	05/15/35	+115
9	05/05/25	DTE	DTE Electric Company	Secured	300	4.250%	Aa3	A	05/14/27	+45
10	05/05/25	DTE	DTE Electric Company	Secured	500	5.250%	Aa3	A	05/15/35	+93
11	05/05/25	DTE	DTE Electric Company	Secured	500	5.850%	Aa3	A	05/15/55	+103
12	05/05/25	ETR	Entergy Arkansas (Reopening)	Secured	300	5.450%	A2	A	03/01/34	+97
13	05/06/25	D	Dominion Energy Inc	Unsecured	1,000	4.600%	Baa2	BBB	05/15/28	+88
14	05/12/25	AEP	AEP Transmission	Unsecured	425	5.375%	A2	BBB+	06/15/35	+100
15	05/12/25	EXC	Commonwealth Edison	Secured	725	5.950%	A1	A	06/01/55	+105
16	05/12/25	DUK	Duke Energy Indiana	Secured	300	5.900%	Aa3	A	05/15/55	+103
17	05/12/25	PNW	Pinnacle West Capital	Unsecured	400	4.900%	Baa2	BBB	05/15/28	+93
18	05/12/25	PNW	Pinnacle West Capital	Unsecured	400	5.150%	Baa2	BBB	05/15/30	+108
19	05/12/25	SRE	Southern California Gas	Secured	600	5.450%	Aa3	A	06/15/35	+105
20	05/12/25	SRE	Southern California Gas	Secured	500	6.000%	Aa3	A	06/15/55	+120
21	05/13/25	CPXCN	Capital Power US Holdings	Unsecured	700	5.257%	NR	BBB-	06/01/28	+125
22	05/13/25	CPXCN	Capital Power US Holdings	Unsecured	500	6.189%	NR	BBB-	06/01/35	+170
23	05/13/25	EXC	Baltimore Gas & Electric	Unsecured	650	5.450%	A3	A	06/01/35	+98
24	05/13/25	LNT	Interstate Power and Light Co	Unsecured	600	5.600%	Baa1	BBB+	06/29/35	+115
25	05/13/25	TVA	Tennessee Valley Authority	Unsecured	1,500	4.875%	Aaa	AA+	05/15/35	+45
26	05/14/25	PEG	PSEG Power	Unsecured	750	5.200%	Baa2	BBB+	05/15/30	+105
27	05/14/25	PEG	PSEG Power	Unsecured	500	5.750%	Baa2	BBB+	05/15/35	+127
28	05/21/25	FE	Ohio Edison	Unsecured	300	4.950%	A3	BBB+	12/15/29	+80
29	05/28/25	ETR	System Energy Resources Inc (Reopening)	Secured	240	5.300%	Baa2	BBB-	12/15/34	+120
30	06/02/25	PCG	Pacific Gas & Electric	Secured	400	5.000%	Baa1	BBB	06/04/28	+115
31	06/02/25	PCG	Pacific Gas & Electric	Secured	850	6.000%	Baa1	BBB	08/15/35	+160
32	06/02/25	DUK	Duke Energy Ohio	Secured	350	5.300%	A2	A	06/15/35	+88
33	06/11/25	ONCRTX	Oncor Electric Delivery Company	Secured	804	3.625%	A2	A+	06/15/34	MS+120
34	06/12/25	HASI	Hannon Armstrong Sustainable Infrastructure Capital In	Unsecured	600	6.150%	Baa3	BBB-	01/15/31	+225
35	06/12/25	HASI	Hannon Armstrong Sustainable Infrastructure Capital In	Unsecured	400	6.750%	Baa3	BBB-	07/15/35	+245
36	06/16/25	ATO	Atmos Energy Corp	Unsecured	500	5.200%	A2	A-	08/15/35	+80
37	06/16/25	ES	Public Service Co of New Hampshire	Secured	300	4.400%	A1	A	07/01/28	+50
38	06/17/25	XEL	Northern States Power - WI (Reopening)	Secured	250	5.650%	A1	A	06/15/54	+91
39	06/23/25	AEP	Public Service Co. of Oklahoma	Unsecured	800	5.450%	Baa1	BBB+	01/15/36	+115
40	06/23/25	NI	NiSource Inc	Unsecured	900	5.350%	Baa2	BBB+	07/15/35	+105
41	06/23/25	NI	NiSource Inc (Reopening)	Unsecured	750	5.850%	Baa2	BBB+	04/01/55	+115
42	06/30/25	NGGLN	Niagara Mohawk Power	Unsecured	500	4.647%	Baa1	BBB+	10/03/30	+85
43	06/30/25	NGGLN	Niagara Mohawk Power	Unsecured	750	5.996%	Baa1	BBB+	07/03/55	+120
44	08/04/25	D	Dominion Energy	Pref/Hybrid	825	6.000%	Baa3	BBB-	02/15/56	+226
45	08/04/25	XEL	Public Service Company of Colorado	Secured	800	5.150%	A1	A	09/15/35	+97
46	08/04/25	XEL	Public Service Company of Colorado (Reopening)	Secured	200	5.850%	A1	A	05/15/55	+102
47	08/04/25	D	Dominion Energy	Pref/Hybrid	700	6.200%	Baa3	BBB-	02/15/56	+201
48	08/04/25	PPL	Kentucky Utilities Co	Secured	700	5.850%	A1	A	08/15/55	+105
49	08/04/25	CNP	CenterPoint Energy Houston	Secured	600	4.950%	A2	A	08/15/35	+80
50	08/04/25	PPL	Louisville Gas and Electric Co	Secured	700	5.850%	A1	A	08/15/55	+105
51	08/04/25	AGR	New York State Electric & Gas	Unsecured	300	5.050%	Baa1	A-	08/15/35	+88
52	08/05/25	WTRG	Essential Utilities Inc	Unsecured	500	5.250%	Baa2	BBB+	08/15/35	+107
53	08/05/25	TVA	Tennessee Valley Authority	Unsecured	1,250	3.875%	Aa1	AA+	08/01/30	+20
54	08/06/25	PPL	PPL Electric Utilities Corporation	Secured	500	5.550%	A1	A+	08/15/55	+77
55	08/06/25	AES	Indianapolis Power & Light	Secured	350	5.050%	A2	A-	08/15/35	+85
56	08/06/25	AWK	American Water Capital Corp	Unsecured	900	5.700%	Baa1	A	09/01/55	+90
57	08/07/25	PEG	Public Service Electric & Gas Co	Secured	450	4.900%	A1	A	08/15/35	+67
58	08/11/25	EVRG	Evergy Metro Inc	Secured	400	5.125%	A2	A	09/15/35	+87
59	08/11/25	FE	FirstEnergy Transmission	Unsecured	450	4.750%	Baa2	BBB+	01/15/33	+77
60	08/12/25	PNW	Arizona Public Service Co (Reopening)	Unsecured	250	5.700%	Baa1	BBB+	08/15/34	+90
61	08/12/25	PNW	Arizona Public Service Co	Unsecured	700	5.900%	Baa1	BBB+	08/15/55	+105
62	08/14/25	AES	Dayton Power & Light Company	Secured	375	4.550%	Baa1	BBB+	08/15/30	+75
63	08/19/25	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	700	4.150%	A2	NR	08/25/28	+48
64	08/26/25	SRE	Sempra	Pref/Hybrid	800	6.375%	Baa3	BBB-	04/01/56	+263
65	09/02/25	SO	Alabama Power Company	Unsecured	500	4.300%	A1	A	03/15/31	+60
66	09/02/25	FE	Jersey Central Power & Light Co	Unsecured	350	4.150%	A3	BBB	01/15/29	+55
67	09/02/25	FE	Jersey Central Power & Light Co	Unsecured	500	4.400%	A3	BBB	01/15/31	+70
68	09/02/25	FE	Jersey Central Power & Light Co	Unsecured	500	5.150%	A3	BBB	01/15/36	+90
69	09/03/25	SO	Southern Company Gas Capital Corp	Unsecured	425	4.050%	Baa1	A-	09/15/28	+52
70	09/03/25	SO	Southern Company Gas Capital Corp	Unsecured	425	5.100%	Baa1	A-	09/15/35	+93
71	09/03/25	EXC	PECO Energy Co	Secured	525	4.875%	Aa3	A	09/15/35	+68
72	09/03/25	EXC	PECO Energy Co	Secured	525	5.650%	Aa3	A	09/15/55	+75
73	09/04/25	BRKHEC	Sierra Pacific Power Co	Pref/Hybrid	450	6.200%	Baa3	BBB	12/15/55	+255
74	09/08/25	DUK	Duke Energy Corporation	Unsecured	1,000	4.950%	Baa2	BBB	09/15/35	+95
75	09/08/25	DUK	Duke Energy Corporation	Unsecured	750	5.700%	Baa2	BBB	09/15/55	+103
76	09/08/25	D	Virginia Electric and Power	Unsecured	825	4.900%	A3	BBB+	09/15/35	+87
77	09/08/25	D	Virginia Electric and Power	Unsecured	875	5.600%	A3	BBB+	09/15/55	+92
78	09/08/25	PSD	Puget Sound Energy Inc	Secured	500	5.598%	A2	A-	09/15/55	+88
79	09/08/25	LNT	Interstate Power and Light Co	Unsecured	300	5.600%	Baa1	BBB+	10/01/55	+95
80	09/08/25	DTE	DTE Energy Company ($25 Par)	Pref/Hybrid	600	6.250%	Baa3	BBB-	10/01/85	-
81	09/09/25	DTE	DTE Energy Company	Unsecured	250	4.875%	Baa2	BBB	06/01/28	+57
82	09/09/25	DTE	DTE Energy Company	Unsecured	550	5.050%	Baa2	BBB	10/01/35	+102
83	09/15/25	AEE	Ameren Illinois (Reopening)	Secured	350	5.625%	A1	A	03/01/55	+75
84	09/15/25	RWE	RWE Finance Corp	Unsecured	1,000	5.125%	Baa2	-	09/18/35	+115
85	09/15/25	RWE	RWE Finance Corp	Unsecured	1,000	5.875%	Baa2	-	09/18/55	+125
86	09/16/25	SO	Southern Power Co	Unsecured	550	4.250%	Baa1	BBB+	10/01/30	+70
87	09/16/25	SO	Southern Power Co	Unsecured	550	4.900%	Baa1	BBB+	10/01/35	+90
88	09/18/25	ATO	Atmos Energy Corp	Unsecured	600	5.450%	A2	A-	01/15/56	+77
89	09/18/25	WEC	Wisconsin Electric Power Co	Unsecured	500	4.150%	A2	A-	10/15/30	+50
90	09/22/25	AEP	AEP Texas (Reopening)	Unsecured	150	5.700%	Baa3	BBB+	05/15/34	+97
91	09/22/25	AEP	AEP Texas	Unsecured	750	5.850%	Baa3	BBB+	10/15/55	+112
92	09/23/25	LNT	Alliant Energy Corp	Pref/Hybrid	725	5.750%	Baa3	BBB-	04/01/56	+208
93	09/23/25	AEP	American Electric Power Co	Pref/Hybrid	1,100	5.800%	Baa3	BBB-	03/15/56	+213
94	09/23/25	AEP	American Electric Power Co	Pref/Hybrid	900	6.050%	Baa3	BBB-	03/15/56	+194
95	09/23/25	ENELIM	Enel Finance International NV	Unsecured	1,000	4.125%	Baa1	BBB	09/30/28	+65
96	09/23/25	ENELIM	Enel Finance International NV	Unsecured	1,250	4.375%	Baa1	BBB	09/30/30	+80
97	09/23/25	ENELIM	Enel Finance International NV	Unsecured	1,250	5.000%	Baa1	BBB	09/30/35	+100
98	09/23/25	ENELIM	Enel Finance International NV	Unsecured	1,000	5.750%	Baa1	BBB	9/30/0255	+112
99	09/23/25	ONCRTX	Oncor Electric Delivery	Secured	361	4.200%	A2	A	10/01/35	+105
100	09/24/25	SO	Georgia Power	Unsecured	750	4.000%	A3	A	10/01/28	+112

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-33 (MRB-9)
Page: 5 of 6
Witness: MRBleckman
Date: June 2026

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	09/24/25	SO	Georgia Power (Reopening)	Unsecured	250	4.875%	A3	A	03/15/31	+112
2	09/24/25	SO	Georgia Power	Unsecured	500	5.500%	A3	A	10/01/55	+112
3	09/24/25	NRG	NRG Energy	Secured	625	4.734%	Baa3	BBB-	10/15/30	+102
4	09/24/25	NRG	NRG Energy	Secured	625	5.407%	Baa3	BBB-	10/15/35	+127
5	09/25/25	BKH	Black Hills Corporation	Unsecured	450	4.550%	Baa2	BBB+	01/31/31	+80
6	09/29/25	D	Dominion Energy (Reopening)	Pref/Hybrid	625	6.000%	Baa3	BBB-	02/15/56	+226
7	09/29/25	D	Dominion Energy (Reopening)	Pref/Hybrid	625	6.200%	Baa3	BBB-	02/15/56	+201
8	09/29/25	XEL	Xcel Energy ($25 Par)	Pref/Hybrid	900	6.250%	Baa2	BBB-	10/15/85	+233
9	09/29/25	EMACN	EUSHI Finance Inc	Pref/Hybrid	750	6.250%	NR	BB+	04/01/56	+251
10	09/30/25	CNP	Centerpoint Energy Inc	Pref/Hybrid	700	5.950%	Baa3	BBB-	04/01/56	+222
11	09/30/25	PCG	Pacific Gas and Electric Co (Reopening)	Secured	400	5.000%	Baa1	BBB	06/04/28	+80
12	09/30/25	PCG	Pacific Gas and Electric Co	Secured	850	5.050%	Baa1	BBB	10/15/32	+115
13	09/30/25	PCG	Pacific Gas and Electric Co	Secured	750	6.100%	Baa1	BBB	10/15/55	+137
14	10/01/25	VST	Vistra Operations Co	Secured	750	4.300%	Baa3	BBB-	10/15/28	+75
15	10/01/25	VST	Vistra Operations Co	Secured	500	4.600%	Baa3	BBB-	10/15/30	+93
16	10/01/25	VST	Vistra Operations Co	Secured	750	5.250%	Baa3	BBB-	10/15/35	+118
17	10/06/25	BASINE	Basin Electric Power Cooperative	Unsecured	700	5.850%	A3	A	10/15/55	+110
18	10/15/25	ES	Eversource Energy	Unsecured	600	4.450%	Baa2	BBB	12/15/30	+87
19	10/15/25	ES	NSTAR Electric (Reopening)	Unsecured	300	5.200%	A2	A-	03/01/35	+82
20	11/03/25	NI	NiSource Inc.	Pref/Hybrid	1,000	5.750%	Baa3	BBB-	07/15/56	+204
21	11/03/25	WEC	WEC Energy Group	Pref/Hybrid	600	5.625%	Baa2	BBB	05/15/56	+191
22	11/03/25	BRKHEC	MidAmerican Energy Company	Secured	400	5.500%	Aa2	A	11/15/56	+85
23	11/04/25	ETR	Entergy Corporation	Pref/Hybrid	600	5.875%	Baa3	BBB-	06/15/56	+218
24	11/04/25	ETR	Entergy Corporation	Pref/Hybrid	700	6.100%	Baa3	BBB-	06/15/56	+201
25	11/17/25	ED	Consolidated Edison Co of New York	Unsecured	900	5.750%	A3	A-	11/15/55	+103
26	11/17/25	DTE	DTE Electric Company (Reopening)	Secured	200	5.250%	Aa3	A	05/15/35	+77
27	11/17/25	DTE	DTE Electric Company (Reopening)	Secured	200	5.850%	Aa3	A	05/15/55	+87
28	11/17/25	EVRG	Evergy Missouri West Inc	Secured	300	5.250%	Baa1	A	12/15/35	+113
29	11/18/25	SR	Spire Inc.	Pref/Hybrid	450	6.250%	Baa3	BBB-	06/01/56	+256
30	11/18/25	SR	Spire Inc.	Pref/Hybrid	450	6.450%	Baa3	BBB-	06/01/56	+233
31	11/18/25	CNL	Cleco Power	Unsecured	350	5.300%	A3	A-	01/15/36	+120
32	11/24/25	DUK	Duke Energy Florida	Secured	500	4.200%	A1	A	12/01/30	+62
33	11/24/25	DUK	Duke Energy Florida	Secured	600	4.850%	A1	A	12/01/35	+82
34	12/01/25	EVRG	Evergy Kansas Central Inc (Reopening)	Secured	300	5.250%	A2	A	03/15/35	+90
35	12/01/25	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	650	3.950%	A2	NR	12/10/27	+45
36	12/01/25	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	400	4.300%	A2	NR	12/10/30	+65
37	12/02/25	LNT	Wisconsin Power and Light Co	Unsecured	300	5.700%	Baa1	A-	12/15/55	+98
38	12/02/25	NEE	Florida Power & Light	Secured	650	4.700%	Aa2	A+	02/15/36	+65
39	12/02/25	NEE	Florida Power & Light	Secured	1,150	5.600%	Aa2	A+	02/15/66	+90
40	12/02/25	WEC	Wisconsin Electric Power Co	Unsecured	300	3.950%	A2	A-	03/01/29	+42
41	12/03/25	AEP	American Electric Power Co (Reopening)	Pref/Hybrid	400	5.800%	Baa3	BBB-	03/15/56	+213
42	12/03/25	AEP	American Electric Power Co (Reopening)	Pref/Hybrid	600	6.050%	Baa3	BBB-	03/15/56	+194
43	12/08/25	TXNM	TXNM Energy Inc.	Pref/Hybrid	350	7.000%	Ba1	BB+	07/31/56	+325
44	01/05/26	CEG	Constellation Energy Generation LLC	Unsecured	300	FRN	Baa1	BBB+	01/08/28	SOFR+60
45	01/05/26	CEG	Constellation Energy Generation LLC	Unsecured	900	3.900%	Baa1	BBB+	01/08/28	+48
46	01/05/26	CEG	Constellation Energy Generation LLC	Unsecured	750	4.400%	Baa1	BBB+	01/15/31	+73
47	01/05/26	CEG	Constellation Energy Generation LLC	Unsecured	800	5.875%	Baa1	BBB+	01/15/66	+113
48	01/05/26	ETR	Entergy Arkansas	Secured	500	4.950%	A2	A	01/15/36	+83
49	01/05/26	ETR	Entergy Arkansas	Secured	500	5.750%	A2	A	01/15/56	+93
50	01/05/26	PEG	Public Service Electric and Gas Co	Secured	500	5.625%	A1	A	01/01/56	+80
51	01/05/26	WEC	Wisconsin Public Service Corp	Unsecured	300	4.250%	A2	A-	01/15/31	+55
52	01/05/26	PEG	Public Service Electric and Gas Co	Secured	500	4.200%	A1	A	01/01/31	+52
53	01/07/26	NGGLN	Niagara Mohawk Power	Unsecured	650	5.112%	Baa1	BBB+	01/12/36	+97
54	01/07/26	NGGLN	Niagara Mohawk Power (Reopening)	Unsecured	350	5.996%	Baa1	BBB+	07/03/55	+107
55	01/12/26	VST	Vistra Operations Co	Secured	1,000	4.700%	Baa3	BBB-	01/31/31	+95
56	01/12/26	VST	Vistra Operations Co	Secured	1,250	5.350%	Baa3	BBB-	01/31/36	+120
57	02/03/26	BRKHEC	PacifiCorp	Pref/Hybrid	1,100	7.125%	Baa3	BB	08/15/56	+329
58	02/03/26	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	600	FRN	A2	NR	08/09/27	SOFR+43
59	02/03/26	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	600	4.050%	A2	NR	02/09/29	+43
60	02/03/26	NEE	NextEra Energy Inc	Unsecured	700	4.400%	Baa1	BBB+	03/01/31	+57
61	02/03/26	NEE	NextEra Energy Inc	Unsecured	600	5.850%	Baa1	BBB+	03/01/56	+97
62	02/04/26	BRKHEC	PacifiCorp	Secured	400	4.250%	A3	BBB+	03/15/29	+65
63	02/04/26	SR	Spire Inc.	Unsecured	400	4.600%	Baa2	BBB+	09/01/31	+82
64	02/17/26	PCG	PG&E Corporation	Pref/Hybrid	1,000	6.850%	Ba3	B	09/15/56	+323
65	02/18/26	PCG	Pacific Gas & Electric (Reopening)	Secured	400	6.100%	Baa1	BBB	01/15/29	+73
66	02/18/26	PCG	Pacific Gas & Electric	Secured	1,000	5.200%	Baa1	BBB	05/01/36	+115
67	02/18/26	PCG	Pacific Gas & Electric	Secured	800	6.000%	Baa1	BBB	05/01/56	+132
68	02/18/26	AEP	Indiana Michigan Power Co	Unsecured	650	5.600%	A2	BBB+	03/15/56	+92
69	02/18/26	EXC	Exelon Corp	Unsecured	775	4.950%	Baa2	BBB+	03/15/36	+92
70	02/18/26	DTE	DTE Electric Co	Secured	800	4.850%	Aa3	A	03/01/36	+78
71	02/18/26	DTE	DTE Electric Co	Secured	800	5.550%	Aa3	A	03/01/56	+85
72	02/19/26	NEE	NextEra Energy Capital Holdings	Pref/Hybrid	1,177	4.200%	Baa2	BBB	02/26/56	+200
73	02/19/26	NEE	NextEra Energy Capital Holdings	Pref/Hybrid	883	4.750%	Baa2	BBB	02/26/56	+180
74	02/19/26	HASI	HA Sustainable Infrastructure Capital Inc.	Unsecured	400	6.000%	Baa3	BBB-	03/15/36	+195
75	02/23/26	WEC	WEC Energy Group (Reopening)	Unsecured	400	4.750%	Baa1	BBB+	01/15/28	+45
76	02/23/26	EIX	Edison International	Unsecured	550	4.800%	Baa2	BB+	03/15/31	+125
77	02/23/26	AEE	Union Electric Company	Secured	450	4.800%	A2	A	03/15/36	+78
78	02/23/26	AEE	Union Electric Company	Secured	450	5.550%	A2	A	03/15/56	+88
79	02/23/26	ETR	Entergy Louisiana	Secured	750	4.900%	A2	A	04/15/36	+88
80	02/23/26	ETR	Entergy Louisiana	Secured	750	5.650%	A2	A	04/15/56	+98
81	02/23/26	ES	Eversource Energy	Pref/Hybrid	750	6.100%	Baa3	BBB-	08/15/56	+252
82	02/23/26	ES	Eversource Energy	Pref/Hybrid	750	6.350%	Baa3	BBB-	08/15/56	+233
83	02/24/26	EIX	Southern California Edison (Reopening)	Secured	600	5.150%	A2	BBB+	06/01/29	+75
84	02/24/26	EIX	Southern California Edison	Secured	600	4.800%	A2	BBB+	03/15/33	+103
85	02/24/26	IDA	Idaho Power Co	Secured	350	4.850%	A2	A-	03/01/36	+85
86	02/24/26	D	Virginia Electric and Power	Unsecured	1,250	4.950%	A3	BBB+	03/15/36	+95
87	02/24/26	D	Virginia Electric and Power	Unsecured	850	5.700%	A3	BBB+	03/15/56	+105
88	02/24/26	CNP	CenterPoint Energy Houston Electric	Secured	800	4.850%	A2	A	04/01/36	+85
89	02/26/26	XEL	Xcel Energy Inc	Pref/Hybrid	800	5.750%	Baa2	BBB-	12/03/56	+217
90	02/26/26	AEE	Ameren Corporation	Unsecured	400	5.000%	Baa1	BBB	05/15/36	+100
91	03/04/26	DUK	Duke Energy Indiana	Secured	500	4.950%	Aa3	A	03/15/36	+90
92	03/04/26	ETR	Entergy Mississippi	Secured	650	5.050%	A2	A	04/15/36	+97
93	03/05/26	WTRG	Essential Utilities Inc	Unsecured	500	5.125%	Baa2	BBB+	05/15/36	+100
94	03/05/26	AMRTRN	American Transmission Co	Unsecured	300	5.750%	A3	A+	04/01/56	+103
95	03/05/26	EVRG	Evergy Inc	Unsecured	350	4.250%	Baa2	BBB	03/15/29	+65
96	03/05/26	XEL	Northern States Power - MN	Secured	600	4.850%	Aa3	A	05/15/36	+75
97	03/05/26	XEL	Northern States Power - MN	Secured	600	5.550%	Aa3	A	05/15/56	+85
98	03/05/26	BRKHEC	Sierra Pacific Power Co	Pref/Hybrid	600	6.375%	Baa3	BBB	09/15/56	+264
99	03/05/26	AEP	Southwestern Electric Power Co (Reopening)	Unsecured	300	5.300%	Baa2	BBB+	04/01/33	+72
100	03/05/26	AEP	Southwestern Electric Power Co	Unsecured	600	5.200%	Baa2	BBB+	04/01/36	+107

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-33 (MRB-9)
Page: 6 of 6
Witness: MRBleckman
Date: June 2026

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	03/05/26	AEP	Southwestern Electric Power Co	Unsecured	500	5.900%	Baa2	BBB+	04/01/56	+117
2	03/10/26	XEL	Public Service Co of Colorado	Secured	700	4.150%	A1	A	03/13/29	+60
3	03/10/26	XEL	Public Service Co of Colorado	Secured	600	5.050%	A1	A	06/15/36	+95
4	03/10/26	PNW	Arizona Public Service Co	Unsecured	600	5.100%	Baa1	BBB+	03/15/36	+100
5	03/10/26	SRE	Sempra	Unsecured	800	5.250%	Baa2	BBB	03/15/36	+115
6	03/10/26	AEP	AEP Texas Inc	Unsecured	750	5.200%	Baa3	BBB+	04/15/36	+113
7	03/10/26	WEC	Wisconsin Electric Power Co	Unsecured	300	5.650%	A2	A-	03/15/56	+90
8	03/11/26	NGGLN	Brooklyn Union Gas Co	Unsecured	500	5.456%	Baa2	BBB+	03/15/36	+125
9	03/11/26	NGGLN	Brooklyn Union Gas Co (Reopening)	Unsecured	200	6.425%	Baa2	BBB+	07/18/54	+145
10	03/12/26	ONCRTX	Oncor Electric Delivery	Secured	750	4.500%	A2	A	03/15/31	+68
11	03/12/26	ONCRTX	Oncor Electric Delivery	Secured	850	5.900%	A2	A	03/15/56	+105
12	03/16/26	FE	FirstEnergy Pennsylvania Electric Company	Unsecured	550	4.550%	A3	A-	03/15/31	+77
13	03/16/26	FE	FirstEnergy Pennsylvania Electric Company	Unsecured	300	4.150%	A3	A-	03/15/28	+50
14	03/16/26	SRE	San Diego Gas & Electric Co	Secured	625	5.200%	A1	A	03/15/36	+100
15	03/16/26	SRE	San Diego Gas & Electric Co	Secured	475	5.950%	A1	A	03/15/56	+112
16	03/16/26	SO	Southern Co	Pref/Hybrid	1,300	6.000%	Baa2	BBB	04/01/58	+199
17	03/17/26	EMACN	Emera US Finance LLC	Pref/Hybrid	375	6.650%	Ba1	BB+	10/01/56	+287
18	03/17/26	EMACN	Emera US Finance LLC	Pref/Hybrid	375	6.850%	Ba1	BB+	10/01/56	+265
19	03/23/26	BRKHEC	PacifiCorp	Secured	550	5.100%	A3	BBB+	04/15/31	+115
20	03/23/26	OGE	Oklahoma Gas & Electric Company	Unsecured	350	5.900%	A3	A-	04/01/56	+102
21	03/23/26	ITC	ITC Holdings Corp	Unsecured	500	4.875%	Baa2	BBB+	04/15/31	+95
22	03/23/26	ITC	ITC Holdings Corp	Unsecured	400	5.500%	Baa2	BBB+	04/15/36	+118
23	03/23/26	BRKHEC	PacifiCorp	Secured	300	4.650%	A3	BBB+	04/15/29	+85
24	03/23/26	BRKHEC	PacifiCorp	Secured	800	5.450%	A3	BBB+	04/15/33	+133
25	03/23/26	BRKHEC	PacifiCorp	Secured	850	5.800%	A3	BBB+	04/15/36	+150
26	03/23/26	EMACN	Emera US Finance LLC	Unsecured	450	4.500%	Baa3	BBB-	04/01/29	+80
27	03/23/26	EMACN	Emera US Finance LLC	Unsecured	300	5.200%	Baa3	BBB-	04/01/33	+118
28	03/24/26	PSD	Puget Energy Inc	Pref/Hybrid	450	7.000%	Ba1	BB	09/15/56	+296
29	03/24/26	PSD	Puget Energy Inc	Pref/Hybrid	450	7.250%	Ba1	BB	09/15/56	+285
30	03/30/26	AWK	American Water Capital Corp	Unsecured	700	5.200%	Baa1	A	04/01/36	+87
31	04/08/26	VST	Vistra Operations Co LLC	Unsecured	500	4.550%	Ba1	BBB-	10/30/28	+80
32	04/08/26	VST	Vistra Operations Co LLC	Unsecured	1,000	5.000%	Ba1	BBB-	04/30/31	+108
33	04/08/26	VST	Vistra Operations Co LLC	Unsecured	1,000	5.200%	Ba1	BBB-	04/30/33	+118
34	04/08/26	VST	Vistra Operations Co LLC	Unsecured	1,500	5.550%	Ba1	BBB-	04/30/36	+128
35	04/14/26	NRG	NRG Energy Inc	Secured	500	4.955%	Baa3	BBB-	04/30/31	+108

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Peer Company Commission Authorized Equity Ratios
for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-34 (MRB-10)
Page: 1 of 1
Witness: MRBleckman
Date: June 2026

(a) Line No.	(b) State	(c) Proxy Group Company	(d) Regulated Subsidiary	(e) Docket #	(f) Case Type	(g) Date Authorized	(h) Common Equity %
1	Iowa	Alliant Energy Corporation	Interstate Power and Light Company	D-RPU-2023-0002	Electric	09/17/24	51.00%
2	Wisconsin	Alliant Energy Corporation	Wisconsin Power and Light Company	D-6680-UR-125	Electric	11/06/25	55.36%
3	Illinois	Ameren Corporation	Ameren Illinois Company	D-25-0084	Natural Gas	11/19/25	50.03%
4	Arkansas	American Electric Power Company, Inc.	Southwestern Electric Power Company	D-25-003-U	Electric	01/23/26	45.21%
5	Indiana	American Electric Power Company, Inc.	Indiana Michigan Power Company	Ca-45576	Electric	02/23/22	50.00%
6	Kentucky	American Electric Power Company, Inc.	Kentucky Power Company	C-2025-00257	Electric	02/28/26	46.13%
7	Ohio	American Electric Power Company, Inc.	Ohio Power Company	C-25-0392-EL-AIR	Electric	04/01/26	50.88%
8	Oklahoma	American Electric Power Company, Inc.	Public Service Company of Oklahoma	Ca-PUD2023-000086	Electric	01/15/25	51.12%
9	Tennessee	American Electric Power Company, Inc.	Kingsport Power Company	D-21-00107	Electric	10/25/22	53.51%
10	Texas	American Electric Power Company, Inc.	AEP Texas Inc.	D-56165	Electric	10/03/24	42.50%
11	Texas	American Electric Power Company, Inc.	Southwestern Electric Power Company	D-51415	Electric	11/18/21	49.37%
12	Virginia	American Electric Power Company, Inc.	Appalachian Power Company	C-PUR-2024-00024	Electric	11/20/24	49.52%
13	West Virginia	American Electric Power Company, Inc.	Appalachian Power Company	C-24-0854-E-42T	Electric	08/28/25	45.18%
14	Alaska	Avista Corporation	Alaska Electric Light and Power Company	D-U-22-078	Electric	08/31/23	60.70%
15	Idaho	Avista Corporation	Avista Corporation	C-AVU-G-25-01	Natural Gas	08/29/25	50.00%
16	Oregon	Avista Corporation	Avista Corporation	D-UG-519	Natural Gas	05/23/25	50.00%
17	Washington	Avista Corporation	Avista Corporation	D-UG-240007	Natural Gas	12/20/24	48.50%
18	South Carolina	Dominion Energy, Inc.	Dominion Energy South Carolina, Inc.	D-2024-34-E	Electric	08/08/24	52.51%
19	North Carolina	Dominion Energy, Inc.	Virginia Electric and Power Company	E-22, Sub 694	Electric	01/14/25	52.50%
20	Virginia	Dominion Energy, Inc.	Virginia Electric and Power Company	C-PUR-2025-00058	Electric	11/25/25	53.24%
21	North Carolina	Duke Energy Corporation	Duke Energy Carolinas, LLC	D-E-7 Sub 1276	Electric	12/15/23	52.50%
22	South Carolina	Duke Energy Corporation	Duke Energy Carolinas, LLC	D-2025-172-E	Electric	12/04/25	53.00%
23	Florida	Duke Energy Corporation	Duke Energy Florida, LLC	D-20240025-EI	Electric	08/21/24	53.00%
24	Indiana	Duke Energy Corporation	Duke Energy Indiana, LLC	Ca-46038	Electric	01/29/25	53.03%
25	Kentucky	Duke Energy Corporation	Duke Energy Kentucky, Inc.	C-2025-00125	Natural Gas	12/23/25	54.42%
26	Ohio	Duke Energy Corporation	Duke Energy Ohio, Inc.	C-22-0507-GA-AIR	Natural Gas	11/01/23	52.32%
27	North Carolina	Duke Energy Corporation	Duke Energy Progress, LLC	D-E-2 Sub 1300	Electric	08/18/23	53.00%
28	South Carolina	Duke Energy Corporation	Duke Energy Progress, LLC	D-2025-154-E	Electric	11/20/25	53.00%
29	North Carolina	Duke Energy Corporation	Piedmont Natural Gas Company, Inc.	D-G-9 Sub 837	Natural Gas	01/07/25	52.73%
30	South Carolina	Duke Energy Corporation	Piedmont Natural Gas Company, Inc.	D-2023-7-G	Natural Gas	10/05/23	53.13%
31	Tennessee	Duke Energy Corporation	Piedmont Natural Gas Company, Inc.	D-25-00036	Natural Gas	11/25/25	52.13%
32	Arkansas	Entergy Corporation	Entergy Arkansas, LLC	D-16-036-FR	Electric	12/12/25	47.96%
33	Louisiana	Entergy Corporation	Entergy New Orleans, LLC	D-UD-18-07	Electric	10/19/23	55.00%
34	Texas	Entergy Corporation	Entergy Texas, Inc.	D-53719	Electric	08/03/23	51.21%
35	Oregon	IDACORP, Inc.	Idaho Power Company	D-UE-426	Electric	09/23/24	50.00%
36	Idaho	IDACORP, Inc.	Idaho Power Company	C-IPC-E-25-16	Electric	12/30/25	51.00%
37	Florida	NextEra Energy, Inc.	Florida Power & Light Company	D-20250011-EI	Electric	11/20/25	59.60%
38	Arkansas	OGE Energy Corp.	Oklahoma Gas and Electric Company	D-18-046-FR	Electric	03/07/24	51.73%
39	Oklahoma	OGE Energy Corp.	Oklahoma Gas and Electric Company	PUD2023-000087	Electric	11/26/24	53.50%
40	Arizona	Pinnacle West Capital Corporation	Arizona Public Service Company	D-E-01345A-22-0144	Electric	03/05/24	51.93%
41	Kentucky	PPL Corporation	Kentucky Utilities Company	C-2025-00113	Electric	02/16/26	54.36%
42	Kentucky	PPL Corporation	Louisville Gas and Electric Company	C-2025-00114	Electric	02/16/26	53.71%
43	Georgia	Southern Company	Atlanta Gas Light Company	D-42315	Natural Gas	11/18/21	56.00%
44	Tennessee	Southern Company	Chattanooga Gas Company	D-24-00024	Natural Gas	08/12/24	52.54%
45	Georgia	Southern Company	Georgia Power Company	D-44280	Electric	12/20/22	56.00%
46	Mississippi	Southern Company	Mississippi Power Company	D-2019-UN-0219	Electric	06/17/25	55.00%
47	Illinois	Southern Company	Northern Illinois Gas Company	D-25-0055	Natural Gas	11/19/25	50.37%
48	Virginia	Southern Company	Virginia Natural Gas, Inc.	C-PUR-2024-00048	Natural Gas	12/17/25	50.10%
49	Colorado	Xcel Energy Inc.	Public Service Company of Colorado	D-24AL-0049G	Natural Gas	10/25/24	56.02%
50	Minnesota	Xcel Energy Inc.	Northern States Power Company	D-G-002/GR-23-413	Natural Gas	02/13/25	52.83%
51	North Dakota	Xcel Energy Inc.	Northern States Power Company	C-PU-24-376	Natural Gas	02/05/26	52.92%
52	Wisconsin	Xcel Energy Inc.	Northern States Power Company	D-4220-UR-126	Electric	11/09/23	53.16%
53	New Mexico	Xcel Energy Inc.	Southwestern Public Service Company	C-22-00286-UT	Electric	10/19/23	54.70%
	Average Equity Ratio						**52.06%**

Source: Individual state commission electronic docket records search.

Selection Criteria:
1. Regulated subsidiary of the Company's ROE proxy group. Refer to Exhibit A-14 (AEB-1), Sch D-5, page 2.
2. Rate order issued from January 1, 2021 through April 15, 2026.
3. Rate order available through online docket search that includes an authorized equity ratio
4. For each regulated subsidiary, latest authorized equity ratio for each state / jurisdiction.

Note: Excludes final orders received by in-state proxy DTE Energy as well as the Company.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
State Regulatory Evaluations
for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-35 (MRB-11)
Page: 1 of 1
Witness: MRBleckman
Date: June 2026

Line No.	(a) Tier	(b) State	(c) Company	(d) Equity Ratio	(e) ROE	(f) (d) x (e) Rate of Return
1	Tier 1A	Alabama	Alabama Power	55.00%	10.87%	5.98%
2	Tier 1B	Florida	FPL	60.00%	10.80%	6.48%
3		Georgia	Georgia Power	56.00%	10.50%	5.88%
4		Pennsylvania	UGI (PA)	54.02%	9.85%	5.32%
5	Tier 1C	Wisconsin	WEC	52.43%	10.13%	5.31%
6		North Carolina	Duke Energy	53.00%	9.95%	5.27%
7		Iowa	IPL (IA)	51.00%	9.65%	4.92%
8	Average	Michigan[1]	Consumers Energy	50.00%	9.86%	4.93%

Source: Columns (a)-(c): March 2026 S&P Global Market Intelligence Report - RRA Regulatory Focus - State Regulatory Evaluations - Energy.
Columns (d) & (e): Company materials, S&P Capital IQ, investor presentations, and credit rating reports.
Column (f): Column (d) times column (e).

[1]In August 2024, Michigan's state regulatory ranking was downgraded from Above Average Tier 1C to Average.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cumulative Annual Interest Savings
for the Projected Year Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-36 (MRB-12)
Page: 1 of 1
Witness: MRBleckman
Date: June 2026

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Line			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
1	S&P Senior Secured Debt Credit Rating		BBB+	BBB+	BBB+	A-	A	A	A	A	A	A	A	A	A	A	A	A	
2	Debt Issued ($ millions)	A	$ 100	$ -	$ 299	$ 425	$ 250	$ 250	$ 450	$ 835	$ 1,900	$1,001	$ 1,361	$ 335	$ 800	$ 1,910	$ 1,300	$ 1,125	$12,340
3	Interest Spread Differential vs. BBB-	B	0.93%	0.99%	1.24%	0.82%	0.82%	0.53%	0.72%	0.61%	0.22%	0.84%	0.74%	0.56%	0.89%	1.32%	0.41%	0.65%	
4	Annual Interest Savings ($ millions)	A x B	$ 1	$ -	$ 4	$ 3	$ 2	$ 1	$ 3	$ 5	$ 4	$ 8	$ 10	$ 2	$ 7	$ 25	$ 5	$ 7	
5	Cumulative Annual Interest Savings ($ millions)		$ 1	$ 1	$ 5	$ 8	$ 10	$ 11	$ 15	$ 20	$ 24	$ 32	$ 42	$ 44	$ 51	$ 77	$ 82	$ 89	**$ 89**
								Annual savings repeats throughout entire life of the debt.										
6	BBB- Rating Issuance Spread	C	2.17%	2.55%	2.47%	1.71%	1.69%	1.63%	1.83%	1.47%	1.15%	1.97%	2.01%	1.35%	2.29%	2.69%	1.49%	1.52%	
7	Current Rating Issuance Spread (Line 2)	D	1.24%	1.56%	1.24%	0.90%	0.87%	1.11%	1.11%	0.86%	0.93%	1.13%	1.27%	0.79%	1.39%	1.37%	1.07%	0.88%	
8	Issuance Spread Differential vs. BBB-	C - D	0.93%	0.99%	1.24%	0.82%	0.82%	0.53%	0.72%	0.61%	0.22%	0.84%	0.74%	0.56%	0.89%	1.32%	0.41%	0.65%	

Source: All issuance spreads per the Barclays Bank Utility Deal listing.
Line 3: Annual average fixed rate issuance spread versus BBB-, calculated in line 8.
Line 6: Annual average fixed rate BBB- issuance spread.
Line 7: Annual average fixed rate issuance spread for current ratings shown in Line 1.
Line 8 = Line 6 - Line 7.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Peer Company Revolver Capacity Analysis
for the Projected Year Ending April 30, 2028

Source: S&P Capital IQ

Case No.: U-22070
Exhibit No.: A-37 (MRB-13)
Page: 1 of 1
Witness: MRBleckman
Date: June 2026

(a)	(b)	(c)	(d)	(e)	(f)	(g)
				Dec 31, 2025 (amounts in $000s)		
Line	Company Name	Ticker	Regulated Subsidiary	Revolver Capacity	PP&E	Revolver Capacity % of PP&E
1	Alliant Energy Corporation	LNT	Interstate Power and Light Company	350,000	10,436,000	
2			Wisconsin Power and Light Company	400,000	9,363,000	
3				750,000	19,799,000	3.8%
4						
5	Ameren Corporation	AEE	Ameren Illinois Company	1,300,000	16,567,000	
6			Union Electric Company	1,900,000	20,674,000	
7				3,200,000	37,241,000	8.6%
8						
9	Dominion Resources, Inc.	D	Dominion Energy South Carolina, Inc.	900,000	12,449,000	
10			Virginia Electric and Power Company	4,000,000	61,608,000	
11				4,900,000	74,057,000	6.6%
12						
13	DTE Energy Company	DTE	DTE Electric Company	1,000,000	25,120,000	
14			DTE Gas Company	300,000	7,092,000	
15				1,300,000	32,212,000	4.0%
16						
17	Duke Energy Corporation	DUK	Duke Energy Carolinas, LLC	1,650,000	41,946,000	
18			Duke Energy Florida, LLC	700,000	24,944,000	
19			Duke Energy Indiana, LLC	850,000	13,781,000	
20			Duke Energy Kentucky, Inc.	250,000	2,536,400	
21			Duke Energy Ohio, Inc.	700,000	10,820,000	
22			Duke Energy Progress, LLC	1,675,000	28,581,000	
23			Piedmont Natural Gas Company, Inc.	1,000,000	9,159,000	
24			Progress Energy, Inc.	2,375,000	53,529,000	
25				9,200,000	185,296,400	5.0%
26						
27	Entergy Corporation	ETR	Entergy Arkansas, LLC	405,000	11,360,707	
28			Entergy Louisiana, LLC	610,000	21,946,779	
29			Entergy Mississippi, LLC	300,000	7,130,798	
30			Entergy New Orleans, LLC	25,000	1,532,345	
31			Entergy Texas, Inc.	300,000	8,487,879	
32			System Energy Resources, Inc.	120,000	2,406,181	
33				1,760,000	52,864,689	3.3%
34						
35	Evergy, Inc.	EVRG	Evergy Kansas Central, Inc.	800,000	13,600,200	
36			Evergy Metro, Inc.	500,000	8,479,200	
37			Evergy Missouri West, Inc.	500,000	4,408,500	
38				1,800,000	26,487,900	6.8%
39						
40	IDACORP, Inc.	IDA	Idaho Power Company	400,000	7,636,558	5.2%
41						
42	NextEra Energy, Inc.	NEE	Florida Power & Light Company	4,426,000	81,755,000	5.4%
43						
44	OGE Energy Corporation	OGE	Oklahoma Gas and Electric Company	550,000	12,722,500	4.3%
45						
46	Pinnacle West Capital Corporation	PNW	Arizona Public Service Company	1,250,000	23,792,784	5.3%
47						
48	PPL Corporation	PPL	Kentucky Utilities Company	600,000	8,947,000	
49			Louisville Gas and Electric Company	600,000	7,117,000	
50			PPL Electric Utilities Corporation	750,000	14,568,000	
51			The Narragansett Electric Company	400,000	5,482,000	
52				2,350,000	36,114,000	6.5%
53						
54	Southern Company	SO	Alabama Power Company	1,365,000	28,223,000	
55			Georgia Power Company	2,050,000	51,991,000	
56			Mississippi Power Company	275,000	4,297,000	
57			Southern Company Gas	1,600,000	18,773,000	
58				5,290,000	103,284,000	5.1%
59						
60	Xcel Energy Inc.	XEL	Northern States Power Company - MN	800,000	24,472,000	
61			Northern States Power Company - WI	150,000	4,213,000	
62			Public Service Company of Colorado	1,200,000	28,211,000	
63			Southwestern Public Service Company	600,000	10,763,000	
64				2,750,000	67,659,000	4.1%
65						
66						
67	Average Proxy Group					5.3%
68						
69						
70			**Consumers Energy**	**1,400,000**	**28,355,000**	**4.9%**

MOODY'S RATINGS

Infrastructure and Project Finance

CREDIT OPINION
23 March 2026

Update

Send Your Feedback

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	Baa2
Type	Pref. Stock - Dom Curr
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Consumers Energy Company

Update to credit following outlook change to negative

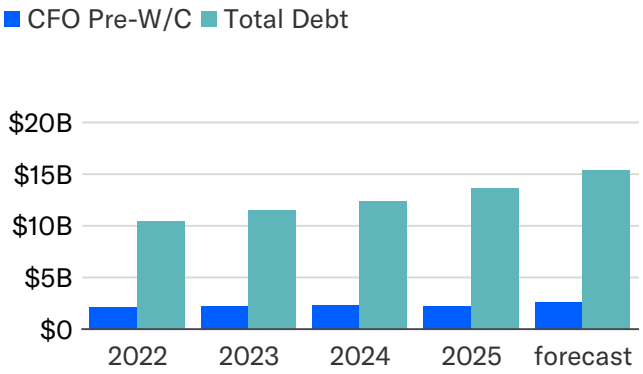
Summary

Consumers Energy Company's (Consumers Energy, A1 senior secured negative) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in a generally credit supportive Michigan regulatory environment. The utility plans to invest approximately $24 billion over the next five years to support its load growth as well as to meet Michigan's clean energy goal by retiring coal-fired power plants and adding new natural gas-fired power plants and renewable sources. Although we view the regulatory environment in Michigan to be credit supportive, the significant step up in the company's capital investment plan without contemporaneous cost recovery through higher equity capital structure and more timely cash recovery mechanisms for large projects, will constrain the company's ability to produce credit metrics that are appropriate for its credit rating. In 2025, Consumers Energy's cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio was 16.8%, excluding securitization bonds, lower than its 18% downgrade threshold primarily due to extreme storms in its service territory. Importantly, a constructive outcome on its pending rate case proceeding as well as supportive regulatory decisions on the company's capital investments will be critical to the company's ability to improve its financial profile.

Recent development

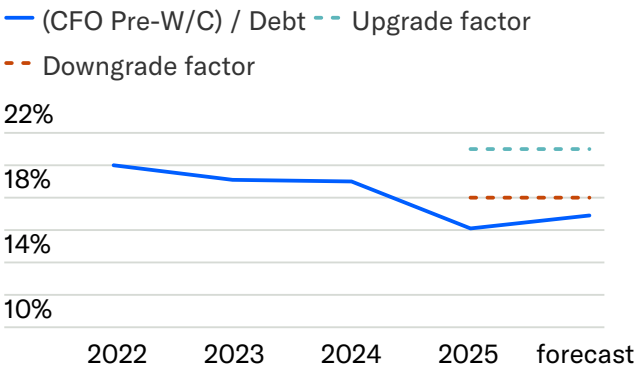
On 19 March, we changed the rating outlook of Consumers Energy to negative from stable. We affirmed its ratings, including the A1 first mortgage bond rating and Prime-2 commercial paper rating. At the same time, we affirmed the ratings of its parent company CMS Energy Corporation (CMS) and maintained its stable rating outlook.

Exhibit 1
CFO Pre-W/C and Total Debt



All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Forecast reflects 2 year average of 2026F and 2027F.
Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Exhibit 2
Consumers' metric is likely to remain pressured below 18%



All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Forecast reflects 2 year average of 2026F and 2027F.
When adjusting for the impact of securitization debt, Consumers Energy's CFO pre-W/C to debt ratio would be 20.5%, 20.1% and 16.8% in 2023, 2024 and 2025, respectively.
Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Credit strengths

» Generally credit supportive regulatory environment in Michigan

» Several timely cost recovery mechanisms including future test years applied during rate cases

Credit challenges

» Significantly higher capital investment plan will require additional debt issuance

» Maintaining regulatory support for these capital investments

» Lack of geographic and regulatory diversity with single state service territory

Rating outlook

The negative outlook for Consumers reflects our expectation that the company's elevated investment plan will continue to pressure its credit metrics including CFO pre-WC to debt below 18%, excluding the impact of securitization debt, without appropriate regulatory support.

Factors that could lead to an upgrade

Given the negative outlook, a rating upgrade for Consumers is not likely in the near term. The outlook could be changed to stable if Consumers' financial profile improves, including a ratio of CFO pre-WC to debt expected to be sustained well above 18%. A constructive outcome on its pending rate case and future regulatory decisions will be important to preserve the company's credit quality and an outlook change back to stable.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Factors that could lead to a downgrade

A rating downgrade of Consumers would be considered if the company's CFO pre-WC to debt ratio remains below 18% on a sustained basis; or if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment, including a less constructive outcome of its pending rate case or future regulatory decisions.

Key indicators

Exhibit 3

Consumers Energy Company

	2022	2023	2024	2025	2026F	2027F
(CFO Pre-W/C + Interest) / Interest Expense	7.1x	5.8x	5.5x	4.8x	5.0x – 5.5x	4.9x – 5.3x
(CFO Pre-W/C) / Debt	20.0%	19.1%	19.0%	16.1%	17.0% - 18.0%	17.0% - 18.0%
(CFO Pre-W/C – Dividends) / Debt	12.7%	13.0%	12.5%	9.5%	10.0% - 11.0%	10.0% - 11.0%
Debt / Book Capitalization	45.1%	45.8%	46.0%	46.4%	44.0% - 48.0%	44.0% - 48.0%

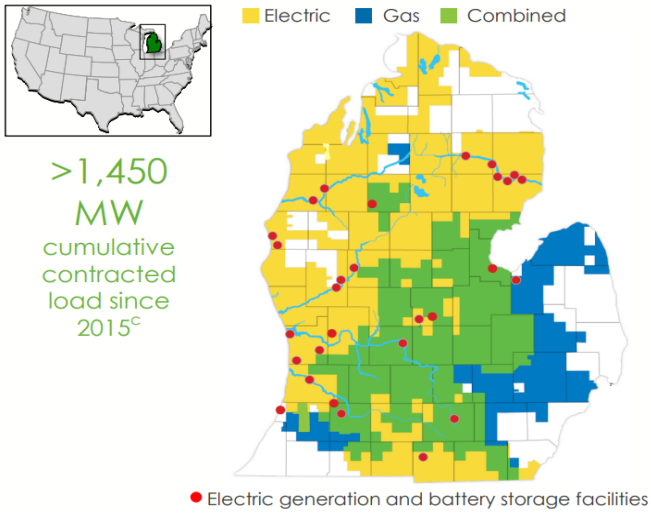
All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Credit metrics included in the exhibit include securitization bonds. When adjusting for the impact of securitization debt, Consumers Energy's CFO pre-W/C to debt ratio would be 20.5%, 20.1% and 16.8% in 2023, 2024 and 2025, respectively
Source: Moody's Financial Metrics™

Profile

Consumers Energy is a vertically integrated electric and gas utility serving approximately 1.9 million electric and 1.8 million gas customers in the state of Michigan with an average rate base of $28 billion at the end of 2025. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. The utility is the primary subsidiary of CMS as it represents over 95% of CMS's consolidated earnings and cash flows. In addition to Consumers Energy, CMS has a subsidiary called NorthStar Clean Energy, a non-utility domestic independent power producer and marketer.

Exhibit 4

Consumers Energy's Service Territory



MW addition figure as of 31 December 2025
Source: Company filings

Detailed credit considerations

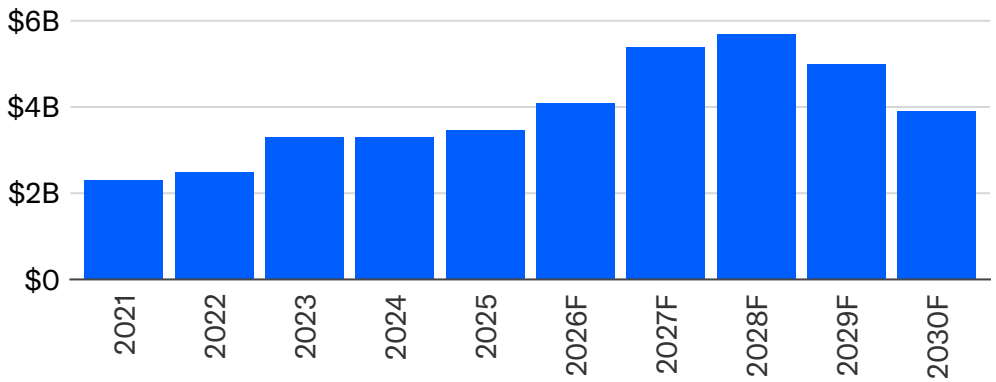
Weakened metrics to remain pressured due to heightened capital investment plan

Consumers Energy's latest investment plan over the next five years is approximately $24 billion, which is approximately $4 billion higher than its previous plan. About 72% of the investments are earmarked for its electric utility, with about even split between generation and distribution investments. Consumers Energy will invest approximately $6.7 billion primarily to maintain and upgrade its gas utility infrastructure; $8.6 billion related to its electric distribution and other infrastructure; and $8.8 billion related to clean energy generation.

The preview of Consumers Energy's upcoming Integrated Resource Plan (IRP), which will be filed in June, included the company's "all-of-the-above" approach with over 13 GW of new power generation capacity. This included expanded renewable investments, including solar, wind and battery storage as well as two new natural gas-fired power plants with total capacity of around 1.5 GW. Based on the investment plan previewed by the company, we expect that Consumers Energy's credit metrics will remain pressured, including its CFO pre-WC to debt ratio sustained below the current threshold for a potential downgrade of 18%. Importantly, a constructive outcome on its pending rate case proceeding as well as supportive regulatory decisions on the company's capital investments will be critical to the company's ability to improve its financial profile. In 2025, Consumer's ratio of CFO pre-WC to debt was approximately 16.8%, excluding the impact of securitization debt. Primarily, the weakness was due to extreme storms in it service territory during the year.

Exhibit 5

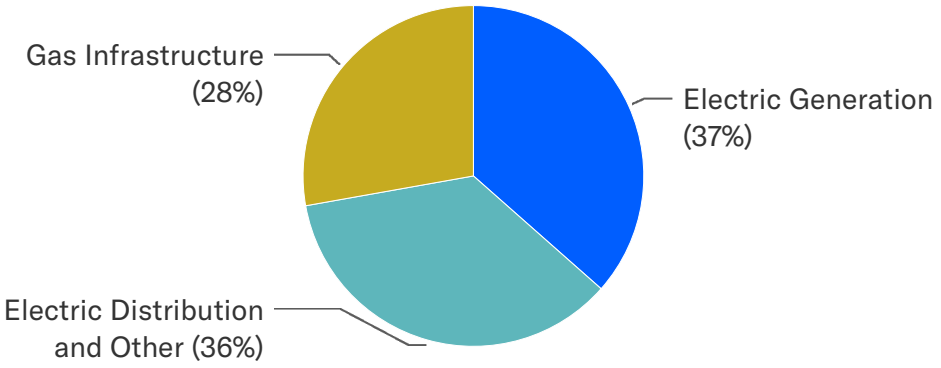
Consumers Energy's elevated capital program will extend at least through 2030



Source: Company filings

Funding for these investments will be provided by internally generated cash flow, the issuance of debt at Consumers Energy and equity contributions from CMS. We expect CMS to increase it equity issuance to support the utility's higher capital expenditure. For example, CMS issued $1 billion of junior subordinated notes in 2025. The company's current financing plan includes approximately $700 million of equity issuance compared to $525 million issued in 2025.

Exhibit 6
Planned Capital Expenditures 2026 - 2030 totals around $24 billion



Total may be higher than 100% due to rounding.
Source: Company filings

Generally supportive regulatory environment

Consumers Energy is regulated by the Michigan Public Service Commission (MPSC) and we view the regulatory framework in Michigan to be more credit supportive than most other states. The state of Michigan has a long history of enacting legislations that are supportive of utility investments in the state. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework has been streamlined, improving both the rate case process and the timeliness of cost recovery. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which had already included pre-construction approval for large generating resources, into an integrated resource planning (IRP) process. The IRP process considers a wide range of factors including fuel costs, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before the construction of major projects.

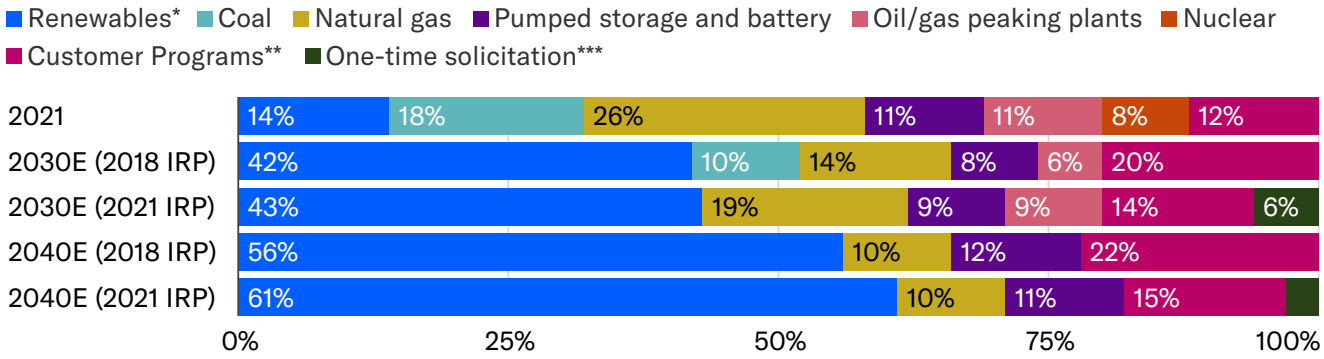
The latest energy legislation enacted in Michigan (2023 Energy Law) laid out the state's renewable energy standards. Under the new law, renewable energy standards were raised to 50% by 2030 and 60% by 2035 from the previous 15% by 2021 requirement. It also set a clean energy standard of 80% by 2035 and 100% by 2040. Under the law, zero to low-carbon emitting sources, such as nuclear generation and natural gas generation with carbon capture, are considered clean energy sources. Along with these new standards, the new legislation expanded the authority of the MPSC to oversee their implementation. Consumers Energy updated its Renewable Energy Plan, which was approved by the MPSC in September 2025.

Consumers Energy will file its next IRP in June. It is subject to the approval of the MPSC and we expect a constructive outcome similar to the last IRP's approval. As a result of the settlement agreement related to Consumers Energy's last IRP, the utility is allowed to record approximately $1.3 billion of the remaining book value of the coal-fired power plants that are anticipated to retire as a regulatory asset and earn a 9% return on equity (ROE) through the remaining life. Instead of securitizing the remaining book value, the settlement minimized the impact of the accelerated coal retirements on Consumers Energy's credit metrics. We viewed this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

In September 2025, the MPSC approved Consumers Energy's latest Renewable Energy Plan, which enables the company to achieve 60% renewable energy by 2035 and 100% clean energy by 2040. Through 2040, Consumers Energy will add up to 8 GW of solar power, which is 3 GW more than what was approved in the company's 2018 IRP. Consumers Energy will grow its solar portfolio to 9 GW and wind portfolio to 4 GW. To backfill the retirement of its Karn 1 and 2 coal units, the utility acquired the Covert natural gas-fired power plant for approximately $815 million in 2023. Under the financial compensation mechanism (FCM), Consumers Energy is allowed earn a return on the PPAs. Pre-tax weighted average cost of capital is approximately 9%. This mechanism allows the utility to earn returns without incurring additional construction risks since building new generation isn't the only way the utility could earn a return, a credit positive. Under the current plan, approximately half of Consumers Energy's renewable generation will be owned and the remaining requirement met through PPAs.

Exhibit 7

Based on the latest IRP settlement, more than 60% of Consumers Energy's generation sources will be renewables by 2040



*Does not include renewable RECs.
**Includes energy waste reduction, demand response, and conservation voltage reduction program.
***One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.
Source: Company filings

Timeliness of cost recovery based on a prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous rate adjustment mechanisms that typically provide cash flow stability and assurance of recovery. For example, Consumers Energy has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability. The GCR mechanism may be adjusted monthly within a capped range to minimize over or under recoveries although interim gas inventory buildup could substantially increase the company's working capital financing when gas prices increase sharply.

Gas utilities in the state also benefit from programs designed to assure recovery of needed infrastructure improvements. The company's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including the replacement of 2,700 miles of natural gas distribution and service pipelines with more durable material.

Active rate case cadence likely to continue

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. Although there was some pressure, due to customer affordability concerns in the state, to lower the allowed ROE level over the last three years, the MPSC has maintained a 9.9% allowed ROE for electric. For its gas utility operations, the allowed ROE is 9.8%. However, further deterioration of the allowed ROE is likely to put negative pressure on the company's overall financial profile.

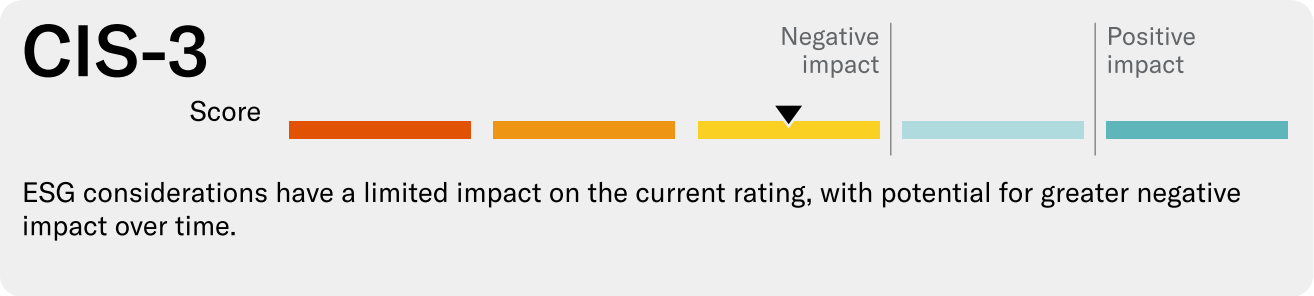
Consumers Energy currently has both electric and gas rate cases pending. In June 2025, Consumers Energy filed its latest electric rate case. Its revised requested increase of $423 million is based on a 10.25% ROE for the test year ending 30 April 2027. The MPSC must issue its final order either before or in April 2026. The final order for its previous electric rate case was received in March 2025. The final order authorized an increase of $154 million, including the approval of a $22 million surcharge related to distribution investments in prior years, in electric base rate revenue based on a 9.9% allowed ROE. The rate increase was also based on a test year ending February 2026 and the total rate base was approximately $14.86 billion.

The company filed its gas rate case in December 2025, requesting an annual rate revenue increase of $240 million based on a 10.25% allowed ROE for the projected period ending 31 October 2027. The final order must be issued either before or in October 2026.

ESG considerations

Consumers Energy Company's ESG credit impact score is CIS-3

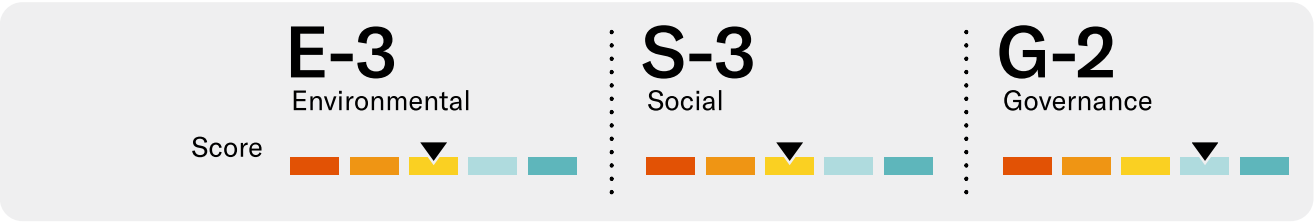
Exhibit 8
ESG credit impact score



Source: Moody's Ratings

Consumers Energy's **CIS-3** indicates that ESG considerations have limited impact on the current credit rating with greater potential for negative impact over time. It reflects some exposure to physical climate risk due to increasing frequency and severity of storm activities. It also incorporates social risks stemming from inherent risk associated with regulated utilities.

Exhibit 9
ESG issuer profile scores



Source: Moody's Ratings

Environmental

Consumers Energy's **E-3** issuer profile score reflects some exposure to physical climate risk, which highlights the increasing severity and frequency of extreme storm activities. It also incorporates exposure to carbon transition risk associated with its gas utility operations and gas-fired power plants. Based on its latest Renewable Energy Plan, the company is projected to increase its generation mix to be 60% renewable by 2035 and 100% clean energy by 2040.

Social

Consumers Energy's **S-3** issuer profile score is primarily related to its customer and regulatory relations as well as demographic and societal trends. The utility's regulatory environment, as well as its interaction with the MPSC, are important in considering the utility's social risk. Also, the safety and reliability of its operations are important social considerations.

Governance

Consumers Energy's **G-2** issuer profile score reflects our view that its governance does not pose a particular risk.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumers Energy's external liquidity sources include a $1.1 billion senior secured revolving credit facility expiring in November 2030. As of 31 December 2025, net availability was $1.094 billion with $6 million of letters of credit outstanding. Consumers Energy also maintains a $300 million senior secured credit facility terminating in November 2028 and had $300 million available as of 31 December 2025. Both facilities are secured by first mortgage bonds. In addition, Consumers Energy has a $100 million senior secured letter of credit facility expiring in May 2027 with $100 million letters of credit outstanding at the end of 2025. It also has a $50 million unsecured letter of credit facility expiring in March 2028 with $43 million letters of credit outstanding, and two $100 million unsecured letter of credit facilities with automatic renewal provisions with $97 million and $100 million letters of credit outstanding, respectively, at the end of the same period. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's $500 million commercial paper program. At 31 December 2025, the company had no commercial paper notes outstanding under the program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at 65%. At 31 December 2025, its debt to capital ratio was 51%.

The utility's continuing capital expenditure program and dividend policy will result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent. In addition, Consumers Energy will manage the financing of its capital investment program to maintain its targeted capital structure authorized by its regulators.

For the period ended 31 December 2025, Consumers Energy generated approximately $2.2 billion of cash from operations, invested $3.3 billion and distributed $900 million of dividends to CMS, resulting in negative free cash flow of approximately $2.0 billion. Given its robust investment plan, we expect Consumers Energy to maintain its negative free cash flow position over the 12-18 months.

In May 2025, Consumers issued $500 million 4.5% first mortgage bonds due 2031 and $625 million 5.05% first mortgage bonds due 2035.

Methodology and scorecard

We use our global Regulated Electric and Gas Utilities rating methodology as the primary methodology for analyzing Consumers Energy Company. The scorecard-indicated outcome reflects the implied senior unsecured rating and the actual rating assigned of A1 is Consumers Energy's senior secured rating, which would be two notches higher than its implied senior unsecured rating.

Exhibit 10

Rating factors

Consumers Energy Company

Regulated Electric and Gas Utilities Industry Scorecard	Current FY Dec-25		Moody's 12-18 month forward view	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.3x	A	5.1x - 5.3x	A
b) CFO pre-WC / Debt (3 Year Avg)	18.0%	Baa	17% - 18%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	11.6%	Baa	10% - 11%	Baa
d) Debt / Capitalization (3 Year Avg)	46.1%	Baa	44% - 48%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned				A1

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Appendix

Exhibit 11

Peer comparison

Consumers Energy Company

	Consumers Energy Company A3 Stable			DTE Electric Company A2 Stable			Northern States Power Company (Minnesota) A2 Stable			Wisconsin Electric Power Company A2 Stable		
	FY	FY	FY	FY	FY	FY	FY	FY	FY	FY	FY	FY
(in $ millions)	Dec-23	Dec-24	Dec-25	Dec-23	Dec-24	Dec-25	Dec-23	Dec-24	Dec-25	Dec-23	Dec-24	Dec-25
Revenue	7,166	7,200	8,132	5,804	6,277	6,885	6,043	5,767	6,307	4,045	3,980	4,494
CFO Pre-W/C	2,190	2,344	2,198	2,565	2,969	2,748	2,261	2,171	2,223	992	1,231	1,168
Total Debt	11,449	12,346	13,642	12,523	13,611	14,852	7,692	8,436	9,330	6,596	7,050	8,075
(CFO Pre-W/C + Interest) / Interest Expense	5.8x	5.5x	4.8x	6.7x	6.4x	5.4x	7.8x	6.8x	6.1x	3.1x	3.5x	3.2x
(CFO Pre-W/C) / Debt	19.1%	19.0%	16.1%	20.5%	21.8%	18.5%	29.4%	25.7%	23.8%	15.0%	17.5%	14.5%
(CFO Pre-W/C – Dividends) / Debt	13.0%	12.5%	9.5%	12.5%	16.1%	12.8%	21.0%	19.9%	19.3%	9.4%	14.1%	7.0%
Debt / Book Capitalization	45.8%	46.0%	46.4%	48.4%	48.4%	47.9%	43.0%	42.3%	42.0%	50.0%	49.6%	49.0%

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Source: Moody's Financial Metrics™

Exhibit 12

Moody's–adjusted cash flow reconciliation

Consumers Energy Company

(in $ millions)	2020	2021	2022	2023	2024	2025
FFO	**1,993.9**	**2,054.1**	**2,124.9**	**2,064.8**	**2,204.9**	**2,288.0**
+/- Other	(136.0)	(13.0)	(29.0)	125.0	139.0	(90.0)
CFO Pre-WC	**1,857.9**	**2,041.1**	**2,095.9**	**2,189.8**	**2,343.9**	**2,198.0**
+/- ΔWC	25.0	(53.0)	(1,098.0)	243.0	105.0	32.0
CFO	**1,882.9**	**1,988.1**	**997.9**	**2,432.8**	**2,448.9**	**2,230.0**
- Div	638.0	723.0	770.0	696.0	796.0	899.0
- Capex	2,183.9	2,066.1	2,255.9	2,259.8	2,850.9	3,313.0
FCF	**(939.0)**	**(801.0)**	**(2,028.0)**	**(523.0)**	**(1,198.0)**	**(1,982.0)**
Revenue	6,189.0	7,021.0	8,151.0	7,166.0	7,200.0	8,132.0
Interest Expense	332.3	313.5	341.9	454.7	524.1	575.6
Net Income	798.3	839.3	883.2	801.7	931.3	1,050.9
Total Assets	25,399.0	27,140.0	29,916.0	31,852.0	34,088.0	37,081.0
Total Liabilities	16,861.5	17,879.5	19,779.5	21,070.5	22,675.5	24,529.4
Total Equity	8,537.5	9,260.5	10,136.5	10,781.5	11,412.5	12,551.6

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Source: Moody's Financial Metrics™

Ratings

Exhibit 13

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Negative
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Bkd Senior Secured	A1
LT IRB/PC	A3
Pref. Stock	Baa2
Commercial Paper	P-2
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Pref. Stock	Ba1

Source: Moody's Ratings

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S&P Global

RRA Regulatory Focus

RRA Regulatory Focus Quarterly Regulatory Evaluations

August 7, 2024

RRA State Regulatory Evaluations — Energy

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For detailed data

Access RRA's State Regulatory Rankings July 2024.

Regulatory Research Associates, a group within S&P Global Commodity Insights, evaluates the regulatory climate for energy utilities in each of the jurisdictions within the 50 states and the District of Columbia — a total of 53 jurisdictions — on an ongoing basis. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

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Executive Summary

Introduction

RRA evaluates the regulatory climate for energy utilities in each of the jurisdictions RRA evaluates the regulatory climate for energy utilities in each of the jurisdictions within the 50 states and the District of Columbia — a total of 53 jurisdictions — on an ongoing basis. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by each jurisdiction's energy utilities.

Each evaluation is based upon consideration of the numerous factors affecting the regulatory process, including gubernatorial involvement, legislation and court activity, and may be adjusted as events occur that cause RRA to modify its view of the regulatory risk for a given jurisdiction.

RRA reviews the ranking of a particular jurisdiction on an ongoing basis as developments occur and then holistically reviews the rankings when preparing the quarterly comprehensive ranking reports. The issues considered are discussed in RRA Research Notes, Commission Profiles, Topical Special Reports and Rate Case analyses. RRA also considers information obtained from contacts with the commissioners and staff, as well as company and government personnel. The final evaluation is an indicator of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative and court actions.

It is important to note that RRA's rankings are from an investor perspective and are intended to provide insight into the relative risk associated with owning the securities of the jurisdictions in question. They are not an assessment of whether regulators are "doing a good job." In addition, the rankings look at not only the commission's actions but those taken by the jurisdiction's legislature, courts and chief executive, as well as the various stakeholders that intervene in the regulatory process.

About This Report

This report provides a discussion of recent changes in RRA's energy regulatory rankings, with details regarding the rationale for these changes. The report also identifies jurisdictions with ongoing proceedings or developing issues that have the potential to impact the relative regulatory risk for utilities operating within a given jurisdiction and, by extension, the ranking of that jurisdiction. The report also provides a discussion of key regulatory issues that impact the sector outlook as a whole. Finally, the report includes an overview of RRA's ranking methodology and the issues RRA examines in deriving the rankings.

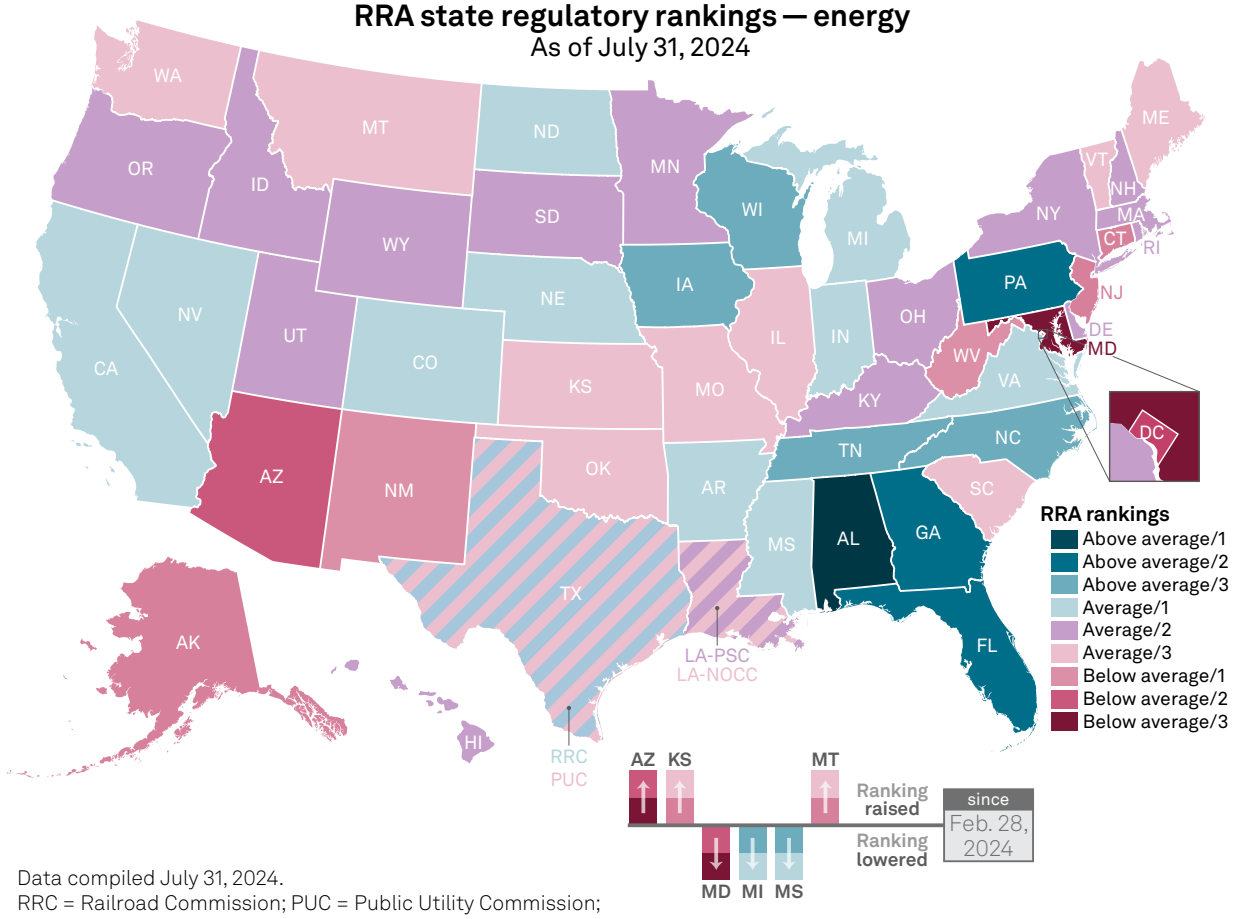
The Take

In light of recent and ongoing developments, Regulatory Research Associates has altered the regulatory rankings of six state-level jurisdictions under coverage and identified nine jurisdictions that bear watching, given recent commission, legislative, gubernatorial and/or court activity.

Developments continue to unfold on a variety of key issues across the regulated utility sector nationwide on an ongoing basis, including evolving public policy related to the energy transition, accelerated capital spending driven largely by programs to meet a variety of societal goals, and higher inflation and interest rates than the US had seen in the prior four decades.

State regulators will play a pivotal role in determining the direction and magnitude of these impacts on the financial performance of the utilities that fall under their purview. How the individual jurisdictions meet these challenges will continue to inform RRA's prospective comparative risk assessments.

RRA state regulatory rankings — energy
As of July 31, 2024



Data compiled July 31, 2024.
RRC = Railroad Commission; PUC = Public Utility Commission;
PSC = Public Service Commission; NOCC = New Orleans City Council.
Map credit: Joe Felizadio.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Recent ranking changes

Following a comprehensive review of the current rankings conducted during July, RRA made six ranking changes. RRA is raising the ranking of **Arizona**, **Kansas** and **Montana**, while lowering the rankings of **Maryland**, **Michigan** and **Mississippi**. The reasons for these changes are discussed in the paragraphs that follow.

Recent rate case decisions issued by the **Arizona** Corporation Commission (ACC) have been relatively constructive. The commission's decision for Pinnacle West Capital Corp. subsidiary Arizona Public Service Co. earlier in 2024 in particular represents a marked improvement over a 2021 ACC ruling that incorporated one of the lowest equity return authorizations observed by RRA in the last 40 years. Several recent commission electric rate orders have also authorized the state's investor-owned utilities to implement a constructive system reliability benefit mechanism to recognize rate base additions between rate cases. Based on these developments, RRA upgraded its rating of the Arizona regulatory environment for energy utilities to Below Average/2 from Below Average/3.

RRA also raised the ranking of the **Kansas** regulatory climate to Average/3 from Below Average/1 to recognize the recent enactment of legislation that allows the use of plant-in-service accounting for electric utility infrastructure investments that are made between a utility's base rate proceedings. Prospectively, the utilities will be permitted to defer, for future recovery, 90% of the depreciation expense and rate of return associated with "qualifying electric plant" investments. The resulting regulatory asset balances, which are to accrue carrying charges at the utility's weighted average cost of capital and be amortized over a 20-year period once included in rates, are to be adjusted to reflect any prudence disallowances ordered by the Kansas Corporation Commission. The new law is expected to mitigate the impact of regulatory lag for the electric utilities operating in the state and improve their prospects for earning their authorized returns.

Additionally, RRA also raised the ranking of the **Montana** regulatory climate to Average/3 from Below Average/1, in recognition of the constructive aspects of recent electric and gas rate case decisions issued by the Montana Public Service Commission for NorthWestern Energy Corp. In these proceedings, the Montana PSC authorized returns on equity that exceeded nationwide averages approved in settled cases for both electric and gas utilities. The authorized electric return on equity (ROE) exceeded nationwide average for all electric cases, while the authorized gas ROE approximated the nationwide average. In addition, the orders allow NorthWestern Energy to defer, for later rate recovery, incremental wildfire expenses that are capped annually. Given that the Montana PSC relies upon historical test periods and average rate base valuations that tend to exacerbate regulatory lag and that the magnitude of wildfire-associated costs appears to be accelerating rapidly for many utilities across the US Northwest, RRA views the ability of NorthWestern Energy to defer its wildfire expense for future recovery as constructive from an investor viewpoint. In pending rate cases before the Montana PSC, NorthWestern Energy is seeking a new balancing account for wildfire management costs, which may help to further reduce regulatory lag as it pertains to investments in wildfire mitigation programs and insurance costs.

By contrast, the **Maryland** regulatory climate has become increasing risky from an investor standpoint since the governor changed in January 2023. The incoming governor, Democrat Wes Moore, quickly removed three members of the Maryland Public Service Commission from office, including the chairman. The incoming chair, who has now been in the position for a little over a year, is a former attorney in the Office of People's Counsel (OPC). In the wake of this change, the OPC has become more vocal and taken a more contentious stance in regulatory proceedings.

RRA state regulatory evaluations

State-by-state listing — Energy

Jurisdiction	Ranking	Jurisdiction	Ranking	Jurisdiction	Ranking
Alabama	Above Average/1	Louisiana — NOCC	Average/3	Ohio	Average/2
Alaska	Below Average/1	Louisiana — PSC	Average/2	Oklahoma	Average/3
Arizona*	Below Average/2	Maine	Average/3	Oregon	Average/2
Arkansas	Average/1	Maryland**	Below Average/3	Pennsylvania	Above Average/2
California	Average/1	Massachusetts	Average/2	Rhode Island	Average/2
Colorado	Average/1	Michigan**	Average/1	South Carolina	Average/3
Connecticut	Below Average/2	Minnesota	Average/2	South Dakota	Average/2
Delaware	Average/2	Mississippi**	Average/1	Tennessee	Above Average/3
District of Columbia	Below Average/2	Missouri	Average/3	Texas — PUC	Average/3
Florida	Above Average/2	Montana*	Average/3	Texas — RRC	Average/1
Georgia	Above Average/2	Nebraska	Average/1	Utah	Average/2
Hawaii	Average/2	Nevada	Average/1	Vermont	Average/3
Idaho	Average/2	New Hampshire	Average/2	Virginia	Average/1
Illinois	Average/3	New Jersey	Below Average/1	Washington	Average/3
Indiana	Average/1	New Mexico	Below Average/1	West Virginia	Below Average/1
Iowa	Above Average/3	New York	Average/2	Wisconsin	Above Average/3
Kansas*	Average/3	North Carolina	Above Average/3	Wyoming	Average/2
Kentucky	Average/2	North Dakota	Average/1		

Data compiled July 31, 2024.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission.
* Ranking raised since Feb. 28, 2024.
** Ranking lowered since Feb. 28, 2024
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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One of the new commissioners is a former state legislator, while the other is an attorney who has represented various stakeholder interests before state and federal regulators. Since these changes, the commission's decisions have become more restrictive from an investor viewpoint, culminating in a June 2024 decision rejecting a multiyear rate plan proposed by Exelon Corp. subsidiary Potomac Electric Power Co., and raising questions regarding future use of that framework in the state.

Contemporaneous with this decision, Anthony O'Donnell, a long-time commissioner who did not participate in issuing the order, resigned, creating uncertainty with respect to the future makeup of the commission and opening up the prospect for another more consumer-oriented replacement.

In light of these developments, RRA is again lowering the ranking for Maryland regulation, this time to Below Average/3 from Below Average/2. This is the third reduction in the jurisdiction's ranking since mid-2023.

RRA is also lowering the ranking of **Michigan** regulation — to Average/1 from Above Average/3. While the jurisdiction remains more constructive than average from an investor viewpoint, the outcomes of recent rate proceedings have been mixed and could indicate a tightening in the regulatory climate.

RRA had placed the state on watch following a 2022 rate case decision in which the Michigan Public Service Commission authorized DTE Energy Inc. subsidiary DTE Electric Co. (DTE-E) an increase in rates that was less than 10% of that requested. At the time, RRA viewed the decision to be an anomaly.

The company filed a new rate case less than three months later, asserting that existing rates and projected electricity sales could not sustain its major capital investment program. Even though the ultimate outcome of this case was more constructive, DTE-E filed a third case within four months of the decision (on March 28, 2024), which is pending. The filing has met significant resistance from consumer groups who characterize the request as "absurd in both the astounding dollars and obnoxious timing," implying that this case will be more contentious than usual.

In a July 2 fully litigated electric rate decision for American Electric Power Co. subsidiary Indiana Michigan Power Co. (IMP), the commission authorized the company a rate increase that was about half of what IMP had requested. Rate of return and expense items accounted for most of the revenue requirement differences; among the items disallowed by the PSC were costs associated with employee incentive compensation and enhanced customer service technology, as well as a company-proposed inflation adjustment. Similar to the DTE-E proceedings, the commission voted to keep IMP's ROE unchanged despite recent increases in interest rates.

While a recently decided (July 23) gas rate case for CMS Energy subsidiary Consumers Energy Co. (CE) was settled rather than fully litigated, the stipulated revenue requirement increase was also less than half of that requested by CE and the authorized ROE remained unchanged from the last case.

While the approved ROEs for DTE, IMP and CE remain above prevailing industry averages, they compare less favorably to these averages, which have risen, albeit modestly, in recent periods.

Against this backdrop, six major utility rate cases are pending, including the aforementioned DTE-E electric rate case, most of which are driven at least in part by capital spending programs intended to comply with state reliability and energy transition policies; outcomes consistent with the above recently completed cases could render it difficult for the companies to continue to support these initiatives.

Also of concern, the electric utilities have been subject to more intensive scrutiny since extensive outages ensued in August 2021, following a major storm.

The **Mississippi** energy utilities continue to operate under streamlined, formulaic alternative rate plans in lieu of general base rate cases. The plans provide for annual rate adjustments and reflect timely recognition of new investments and fluctuations in operating costs. When specified, authorized equity returns as calculated under the plans have generally exceeded prevailing industry averages. However, RRA is lowering the rating of Mississippi regulation at this time to Average/1 from Above Average/3. The change partially reflects the relative inexperience of the three new commissioners that were seated at the Mississippi Public Service Commission earlier in 2024 but is also necessary to maintain a normalized balance in RRA's relative ranking of US regulatory bodies.

In conjunction with the prior review conducted during February 2024, RRA changed the ranking of **Virginia** regulation, raising it to Average/1 from Average/2, to reflect the removal of significant regulatory uncertainty with the election of two individuals to fill long-standing vacancies on the Virginia State Corporation Commission.

RRA also noted that in December 2023, RRA had lowered the ranking of the **Illinois** regulatory climate to Average/3 from Average/2 to reflect the impact of adverse rulings issued for Exelon Corp. subsidiary Commonwealth Edison Co. and Ameren Corp. subsidiary Ameren Illinois Co. in their respective multiyear grid and rate plan proceedings.

Jurisdictions to watch

In addition to the jurisdictions discussed above, where RRA has observed a shift in the regulatory climate, there are nine states where current trends and expected near-term developments could signal a shift in the level of regulatory risk for investors. Even though RRA recently revised the ranking of the regulatory climates in Arizona, Connecticut and Illinois, these jurisdictions continue to bear monitoring.

While RRA raised the ranking of **Arizona** regulation as part of its current review (discussed in the preceding section of this report), ongoing issues merit continued scrutiny, including the ACC's actions earlier in 2024 to reexamine certain long-standing rules, raising the prospect of a rollback of the commission's renewable energy requirements, among other things. While some commissioners have asserted that the rules have unnecessarily burdened ratepayers, the state's major electric utilities are continuing to transition toward more renewable heavy generation portfolios, and a disruption in the policy could have unforeseen consequences for the companies. In addition, three of the ACC's five commissioner seats are up for election this year, as are the governor and both chambers of the Arizona legislature. Changes in the makeup of these branches of state government could result in significant commission policy changes.

After lowering the ranking of **Connecticut** regulation in August 2023, RRA has continued to closely monitor the jurisdiction, which continues to be one of the most challenging in the US. Changes are currently underway to the makeup of the Connecticut Public Utilities Regulatory Authority (PURA), which under state law can be comprised of up to five members. Gov. Ned Lamont (Democrat) recently announced that long-standing commissioner John Betkoski (Democrat), who is serving beyond the end of his term, will be stepping down at the end of 2024. At the same time, Lamont announced the nomination of former state legislator and utility government affairs employee, David Arconti, Jr, (Democrat) as a new PURA commissioner to begin serving Aug. 5, subject to confirmation by the General Assembly in 2025. The other current members of the PURA, Chair Marissa Gillett (Democrat) and Michael Caron (Republican) continue to serve beyond the expiration of their terms.

Recent rate case decisions have demonstrated significant constriction in the regulatory climate and have created additional uncertainty surrounding the overall tenor of regulatory policy in the state. An appeal is ongoing of a 2023 rate case decision, in which the PURA authorized Avangrid Inc. subsidiary The United Illuminating Co. an 8.63% that reflected a 47-basis-point penalty for management and operational performance issues. Even without the penalty, the implied base ROE of 9.10% was among the lowest approved for an energy utility in recent years.

There are two gas rate cases pending for other Avangrid subsidiaries, as well as a legislatively mandated alternative ratemaking proceeding where the PURA is reviewing rules governing multiyear rate plans, earnings-sharing mechanisms, revenue decoupling and potential performance-based ratemaking measures for the electric utilities.

Even though RRA recently lowered the ranking of Illinois to reflect restrictive **Illinois** Commerce Commission (ICC) rate case rulings issued in late 2023, the state continues to bear watching, as Exelon Corp. subsidiary Commonwealth Edison Co. (ComEd) and Ameren Corp. subsidiary Ameren Illinois Co. have revised grid plan filings, pending ICC consideration. The commission is expected to render decisions on the proposals in December.

Further, the ICC's determinations in gas proceedings in late 2023 raise the possibility of the commission continuing to disregard the recommendations put forth by its own internal experts to the detriment of the state's utilities, raising the potential for further constriction in the regulatory climate. Three of the five commissioners are relatively new, having been in office for about a year; so, even though one of the "new" commissioners has served before, the commissioners are evolving in terms of how they work together. In addition to the revised grid plan requests, there is one pending rate case for a relatively small gas utility.

Iowa remains a jurisdiction to watch, considering the Iowa Utilities Commission's (IUC) actions in recent advanced ratemaking decisions regarding new renewable generation projects. In October 2023, the IUC made modifications to a settlement for Alliant Energy Corp. subsidiary Interstate Power and Light Co. (IPL), including a reduction in the authorized ROE for new solar generation; the settlement had specified a 10.75% ROE, but the IUC authorized a 10.25% ROE. While being higher than prevailing industry averages, the modified ROE is below previously approved ROEs for these types of facilities.

Prior to that, in April 2023, the IUC approved Berkshire Hathaway Inc. subsidiary MidAmerican Energy Co.'s Wind PRIME project but rejected a settlement regarding the associated advance ratemaking principles, leaving the ROE to be determined in a future rate case. On rehearing, the parties reached a revised agreement that the IUC approved without modification in December 2023, including an authorization of a 10.75% ROE for the project. However, in the ruling, one commissioner expressed concerns about approving a "premium ROE" within mature renewable energy markets, potentially indicating an eventual conclusion to the practice of approving premium ROEs for these types of investments.

RRA state regulatory evaluations — Energy*

(By category, jurisdictions to watch highlighted)

Above Average/1	Above Average/2	Above Average/3	Average/1	Average/2	Average/3	Below Average/1	Below Average/2	Below Average/3
Alabama	Florida	Iowa	Arkansas	Delaware	Illinois	Alaska	Arizona	Maryland
	Georgia	North Carolina	California	Hawaii	Kansas	New Jersey	Connecticut	
	Pennsylvania	Tennessee	Colorado	Idaho	Louisiana — NOCC	New Mexico	Dist. of Columbia	
		Wisconsin	Indiana	Kentucky	Maine	West Virginia		
			Michigan	Louisiana — PSC	Missouri	New Mexico		
			Mississippi	Massachusetts	Montana	West Virginia		
			Nebraska	Minnesota	Oklahoma			
			Nevada	New Hampshire	South Carolina			
			North Dakota	New York	Texas — PUC			
			Texas — RRC	Ohio	Vermont			
			Virginia	Oregon	Washington			
				Rhode Island				
				South Dakota				
				Utah				
				Wyoming				

Data compiled July 31, 2024.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission.
*Within a given subcategory, states are listed in alphabetical order, not by relative ranking.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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It is noteworthy that two of the three current commissioners are relatively new to the IUC, having joined in May 2023. Consequently, two pending rate cases may face some uncertainty. IPL is in the midst of its first major electric and gas base rate case since 2019; hearings are underway after certain parties signed a nonunanimous settlement. Black Hills Iowa Gas Utility Co. LLC also has a case in progress — its first in about three years.

Kentucky continues to bear watching, as the Kentucky Public Service Commission's pattern of imposing modifications to rate case settlements over the past couple of years remains a cause for concern. The most recent rate case decision for a large utility occurred in January 2024, when the PSC authorized American Electric Power Co. Inc. subsidiary Kentucky Power Co. a rate increase that was meaningfully below the stipulated hike the parties had agreed to in a settlement; the revenue requirement difference stemmed largely from an adverse ruling on transmission-related cost recovery. The commission also rejected a settlement provision that called for the company to implement a distribution reliability rider.

Separately, legislation enacted earlier in 2023 prohibits the Kentucky PSC from approving requests to retire fossil fuel-fired facilities, unless the utility can demonstrate that the plant's retirement would not adversely impact ratepayers or the region's electric grid reliability. The Kentucky PSC recently approved one such proposal — by PPL Corp. subsidiaries Louisville Gas and Electric Co. and Kentucky Utilities Co. — that will result in meaningful changes to the composition of the companies' generation portfolios.

On a constructive note, a separate bill signed in 2023 allows the electric utilities to securitize certain costs associated with retired generation facilities and storm restoration efforts. The PSC recently approved Kentucky Power's securitization request. Even so, it is unclear how the commission will approach future requests.

The term of former Chairman Kent Chandler, a Democrat, expired June 30, and he left the commission instead of seeking reappointment. Gov. Andy Beshear, a Democrat, has not named a replacement. This development adds uncertainty to the state's regulatory climate at the same time that investors are seeking clarity regarding the commission's stance on a variety of regulatory matters.

New Jersey bears watching at this juncture, as Public Service Enterprise Group Inc. subsidiary Public Service Electric and Gas Co. — the largest utility in the state — is in the midst of its first combination electric and gas base rate case in several years. Proceedings are also underway for two of the major gas local distribution companies (LDCs), New Jersey Resources Inc. subsidiary New Jersey Natural Gas Co. and Elizabethtown Gas Co., with Elizabethtown Gas affiliate South Jersey Gas Co. expected to file a case by the end of 2024. The latter two LDCs are held by South Jersey Industries Inc., which is owned by Infrastructure Investments Fund US Holding 2 LP.

With these cases, as well as various energy transition proceedings under way, including a review of the state's Energy Master Plan, the New Jersey Board of Public Utilities is operating with one vacancy and three new members who took office in 2023, including the recently named president.

Due to uncertainty caused by changes in the composition of the **Oklahoma** Corporation Commission (OCC), the combative stance taken in recent proceedings by one of the long-time OCC members and the commission's decision to depart from customary practice and require significant changes to a rate case settlement, RRA lowered its ranking of Oklahoma regulation in November 2023. RRA continues to consider Oklahoma a state to watch, as two of the major energy utilities in the state have substantial rate requests pending.

The regulatory climate in **Texas**, as it pertains to the electric utilities under the purview of the Public Utility Commission of Texas, continues to bear watching. The regulatory framework in Texas and the PUC has been the focus of intense scrutiny, since a 2021 severe weather event caused widespread multiday outages and price spikes within Electric Reliability Council of Texas (ERCOT). While various proceedings are ongoing to transform the framework, the dramatic controversies that arose following that event have largely abated. Recent wildfire and severe storm activity could cause renewed focus on the utilities and the market structure in Texas.

Gov. Greg Abbott's reelection in 2022 provided a measure of stability, though there continues to be turnover at the PUC. One commissioner is serving beyond the end of term that expired in 2021, and both the PUC chair and a newly appointed commissioner are serving pending confirmation by the Senate when the legislature reconvenes in 2025.

Against this backdrop, both CenterPoint Energy Inc. subsidiary CenterPoint Energy Houston Electric Co. and American Electric Power Co. subsidiary AEP Texas Inc. filed rate cases in the first quarter of 2024 and certain intervenors took restrictive positions in their direct testimony in these cases. While a settlement was reached in the AEP Texas case, CenterPoint has filed a motion to withdraw its case in light of ongoing controversy surrounding the company's response to outages caused by Hurricane Beryl and the PUC has initiated a review of CenterPoint's actions during and following the storm.

Several of the utilities have also filed system resiliency proposals in accordance with 2023 legislation; these proceedings may prove challenging in light of the recent weather-related events.

The **Wyoming** regulatory climate bears watching, as the legal and legislative ramifications of a contentious electric general rate case decision for Berkshire Hathaway Inc. subsidiary PacifiCorp continue to play out. The utility has already filed a federal suit against the Wyoming Public Service Commission's order issued in January, arguing that the commission failed to account for the costs of maintaining reserve capacity, as mandated by the Federal Energy Regulatory Commission. PacifiCorp also plans to pursue action in state court, although the company has not specified when it plans to file.

In addition, multiple pieces of legislation enacted during the 2024 session addressed several issues that arose in recent commission proceedings, including recovery of costs associated with neighboring states' environmental policies and cost-tracking mechanisms to allow utilities to recover changes in certain electric supply costs between rate cases.

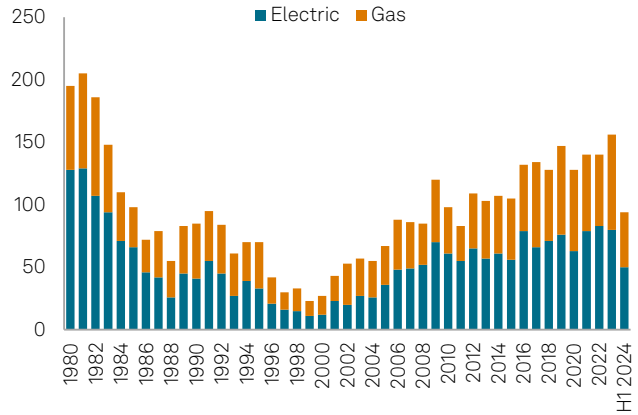
Outlook

Developments continue to unfold on a variety of key issues across the regulated utility sector nationwide. Accelerating capital spending to address a variety of public policy goals, inflation and rising interest rates present challenges for utilities and regulators and are driving an active rate case agenda across the US.

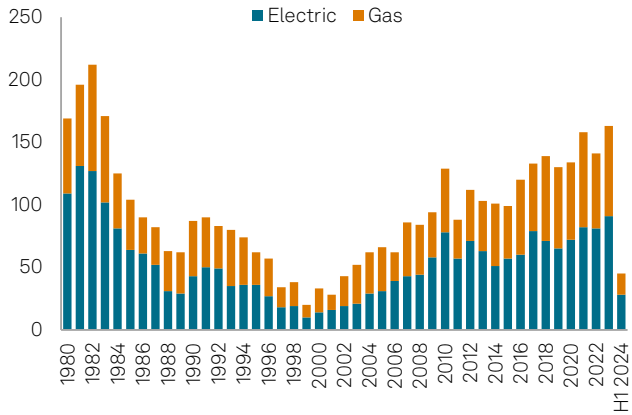
There were 164 electric and gas rate cases decided for the US investor-owned energy utilities in RRA's coverage universe during 2023, with an aggregate $9.3 billion of rate increases approved in those cases. During the first half of 2024, 45 cases were decided, netting $2.3 billion in rate increases.

The covered companies filed 156 new electric and gas rate cases, including limited-issue rider proceedings in 2023, with 94 filed in the first half of 2024. The combined rate increases requested in the 2023 cases aggregated to more than $18.1 billion, while those sought in the 2024 filings added up to almost $12.3 billion.

Major rate cases fillings, 1980-2022



Major rate cases decisions, 1980-2022



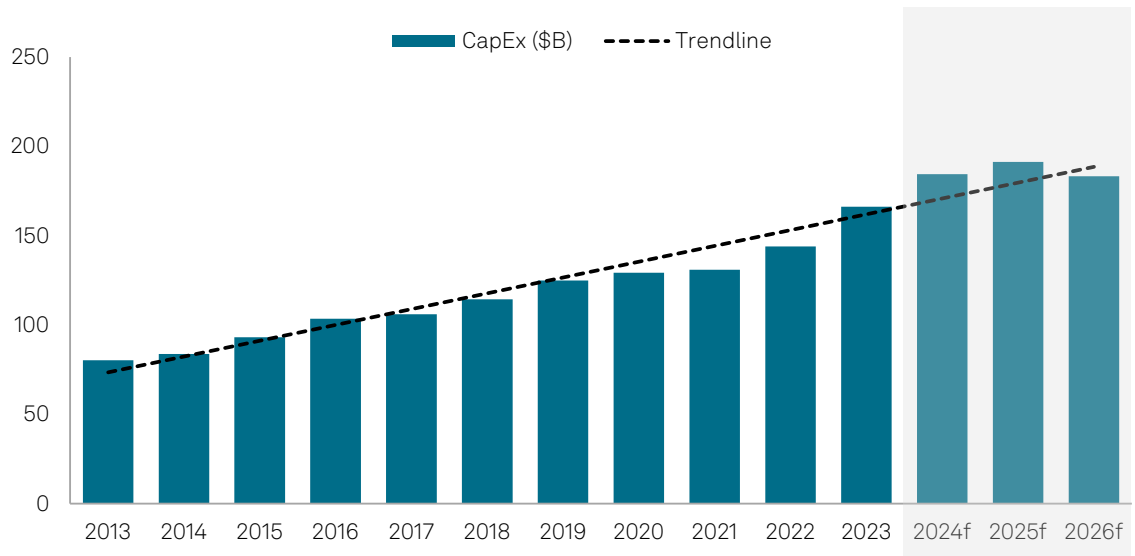
Data compiled July 24, 2024.
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RRA anticipates this trend of robust rate case activity will persist for the foreseeable future, driven by continued expansion in capital spending.

Capital spending has risen steadily since 2006, when the energy utilities included in RRA's sample of the publicly traded US energy utilities reported total actual capital spending of about $52 billion; actual capital spending for the group came in at $166 billion in 2023.

According to data gathered by RRA in March, spending is expected to expand to $184 billion in 2024, increase to $191 billion in 2025 and moderate to $183 billion in 2026, bringing the total for the forecast period (2024–2026) to $559 billion.

Energy actual and estimated capital spending



Data compiled March 27, 2024.
Capex = capital expenditure; f = forecast.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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The impacts of severe weather events, such as hurricanes, winter storms and wildfires, continue to play a more prominent role in utility financial outlooks and are contributing to the active rate case agenda.

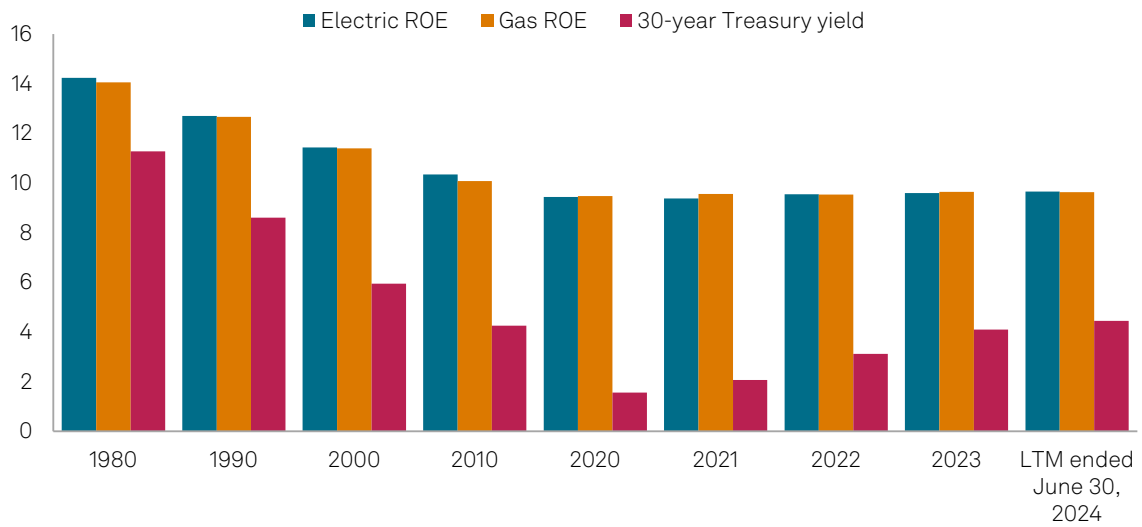
The need to recover the related costs, together with the previously listed factors, will continue to put upward pressure on rates, exacerbating prevailing concerns about ratepayer impacts and affordability, and rendering it challenging for companies to reflect higher financing costs in their authorized returns.

The spread between average authorized ROEs and US Treasury bond yield contracted to roughly 550 basis points in 2023 from almost 800 basis points in 2020. The spread has continued to shrink in 2024, such that for the 12 months ended June 30, 2024, the spread approximated 520 basis points.

Still, the spread remains higher than it was during previous periods. For example, during the early 1980s — another time when the industry faced aggressive capital spending and persistently high levels of inflation and interest rates — the spread between Treasury yields and authorized ROEs was less than 300 basis points.

Average US utility authorized ROEs; 30-year US Treasury bond yields

Select calendar years, 1980-2023, LTM June 30, 2024

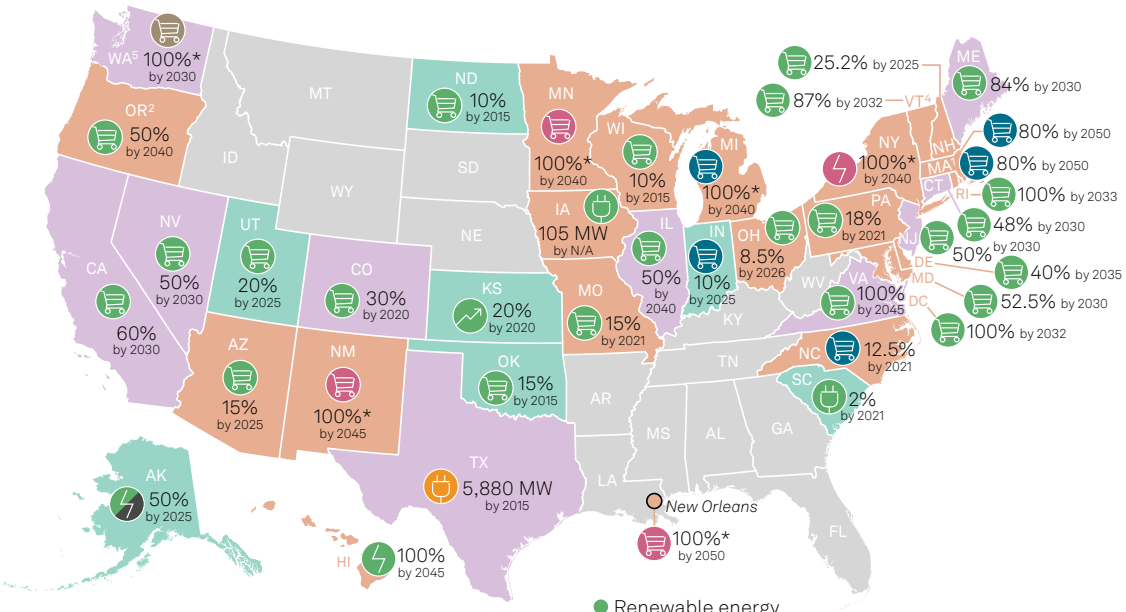


Data compiled July 24, 2024.
ROE=return on equity; LTM = last 12 months.
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The evolving energy transition presents unique challenges for the electric and gas utility sector, but also offers potential for growth. Much of the evolution has come via state legislative initiatives and energy issues continue to be a focus in the current legislative session.

Energy issues will be a factor in the 2024 US presidential election, as well as state level elections, with gubernatorial elections scheduled in 11 states, legislative elections in 44 states and utility commissioners on the ballots in 10 states.

State renewable and clean energy standards and goals



California	100%	2045	Illinois	100%	2050	New Jersey	100%	2035	Washington	100%	2045
Colorado	100%[3]	2050	Maine	100%	2050	Texas	10,000 MW	2025			
Connecticut	100%	2040	Nevada	100%	2050	Virginia	100%	2040			

Data compiled July 29, 2024.
Targets indicate the final requirement and do not include interim steps. The data also does not include voluntary targets adopted by utilities, corporations, public power districts, etc.
* There are interim steps within the renewable portfolio standard that allow for a target to be met with renewable energy resources; however, the carbon-free target is the ultimate target resource policy.
[1] Massachusetts currently has in place a Clean Energy Standard and a separate Renewable Portfolio Standard. The 40% renewables by 2030 standard does not have a stated expiration date; the standard is to increase by 1% each year and will reach 100% renewable energy by 2090. The clean energy standard requires 80% clean energy by 2050.
[2] The state's clean energy targets legislation requires retail electricity providers to reduce emissions by 100% by 2040; while it is a separate policy, it is complementary and works in tandem with the renewable portfolio standard.
[3] The goal is in place for a retail utility that provides service to more than 500,000 customers, such as Xcel Energy, or any utility that decides to opt in.
[4] Legislation enacted in June 2024 modifes and increases the state's renewable portfolio standard to 100% retail sales by 2030 or 2035, depending on the size of the provider. The state's largest utility, Green Mountain Power, must reach the 100% target by 2030.
[5] Washington has an additional 15% renewable energy standard in place. The state's 2045 target of 100% renewable and nonemitting resources is a mandate and not a voluntary goal.
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These factors raise the overall level of uncertainty, or investor risk, across the sector. State regulators will play a pivotal role in determining the direction and magnitude of these impacts on the financial performance of the utilities that fall under their purview. How the individual jurisdictions meet these challenges will continue to inform RRA's prospective comparative risk assessments.

RRA's rankings process

RRA ranks the regulatory climate in a total of 53 state-level jurisdictions, including the District of Columbia and the New Orleans City Council, and two regulatory bodies in Texas — the Public Utility Commission of Texas regulates electric utilities, while the Railroad Commission of Texas regulates gas local distribution companies.

RRA maintains three principal ranking categories — Above Average, Average and Below Average — with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint and Below Average indicating a less constructive, higher-risk regulatory climate.

The numbers 1, 2 and 3 within each principal ranking category indicate relative position. The designation 1 indicates a stronger or more constructive ranking from an investor viewpoint; 2, a midrange rating; and 3, a less constructive rating.

Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."

Methodology

RRA designed the rankings to reflect the interest of equity and fixed-income investors across more than 30 individual metrics. The metrics are scored based on the covering analysts' subjective judgment and then aggregated to create a single score for each state, with certain categories, such as the state's history with respect to authorized equity returns, practice with respect to rate case test years and presence, or lack of alternative ratemaking provisions, weighted more heavily than others.

RRA then ranks the states from lowest to highest and distribute them among the nine categories to create an approximate normal distribution. The team then reviews the distribution and may adjust individual state rankings based on the covering analysts' recommendations, subject to review by a designated panel of senior analysts.

The variables that RRA considers in determining each state's ranking are largely the broad issues detailed in state commission profiles and those that arise in the context of rate cases, generic policy proceedings, legislation and gubernatorial directives.

RRA's articles and reports on these issues are accessible through the S&P Capital IQ Pro platform, as are the jurisdictional commission profiles and RRA's database of major investor-owned utility rate case decisions going back to 1980.

RRA State Regulatory Evaluations*

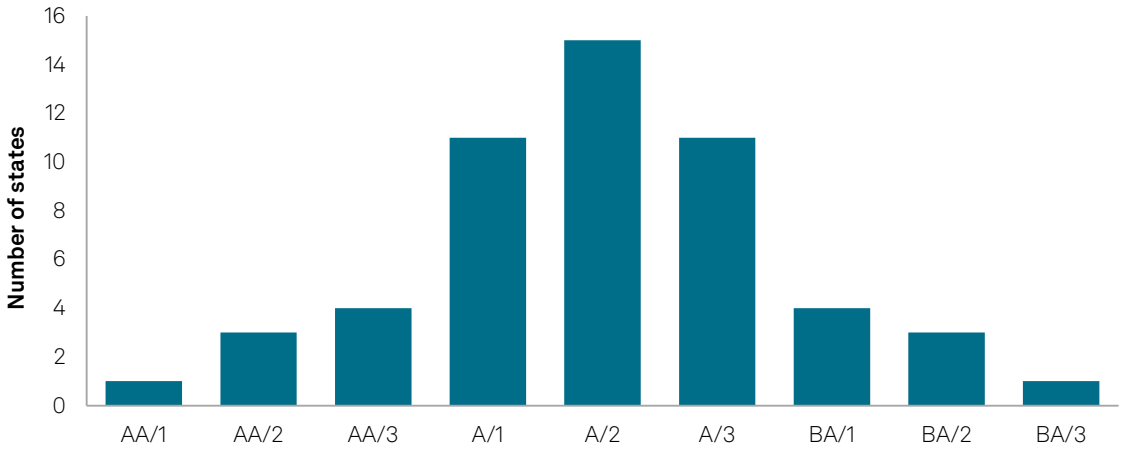
Above Average/1	Average/1	Below Average/1
Alabama	Arkansas	Alaska
	California	New Mexico
	Colorado	New Jersey
	Michigan	West Virginia
	Mississippi	
	Indiana	
	Nebraska	
	Nevada	
	North Dakota	
	Texas — RRC	
	Virginia	
Above Average/2	**Average/2**	**Below Average/2**
Florida	Delaware	Arizona
Georgia	Hawaii	Connecticut
Pennsylvania	Idaho	District of Columbia
	Kentucky	
	Louisiana — PSC	
	Massachusetts	
	Minnesota	
	New York	
	New Hampshire	
	Ohio	
	Oregon	
	Rhode Island	
	South Dakota	
	Utah	
	Wyoming	
Above Average/3	**Average/3**	**Below Average/3**
Iowa	Illinois	Maryland
North Carolina	Louisiana — NOCC	
Tennessee	Kansas	
Wisconsin	Maine	
	Missouri	
	Montana	
	Oklahoma	
	South Carolina	
	Texas — PUC	
	Vermont	
	Washington	

Data compiled July 31, 2024.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission.
* Within a given subcategory, states are listed in alphabetical order, not by relative ranking.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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As implied by the above discussion, the rankings reflect the state regulatory commission's decisions and the impact of the actions taken by the governor, the legislature, the courts and consumer advocacy groups. The policies examined pertain largely to rate cases and the ratemaking process, but RRA also consider issues such as industry restructuring, corporate governance, treatment of proposed mergers and those related to the ongoing energy transition.

In the charts within this report that depict the rankings by category, the jurisdictions within each category are listed in alphabetical order rather than by relative position within the category.

State regulatory rankings distribution — energy



Data compiled July 31, 2024.
AA = Above Average; A = Average; BA = Below Average.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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RRA endeavors to maintain an approximately normal distribution, with most rankings in the three average categories and the remainder split almost evenly between the Above Average and Below Average categories.

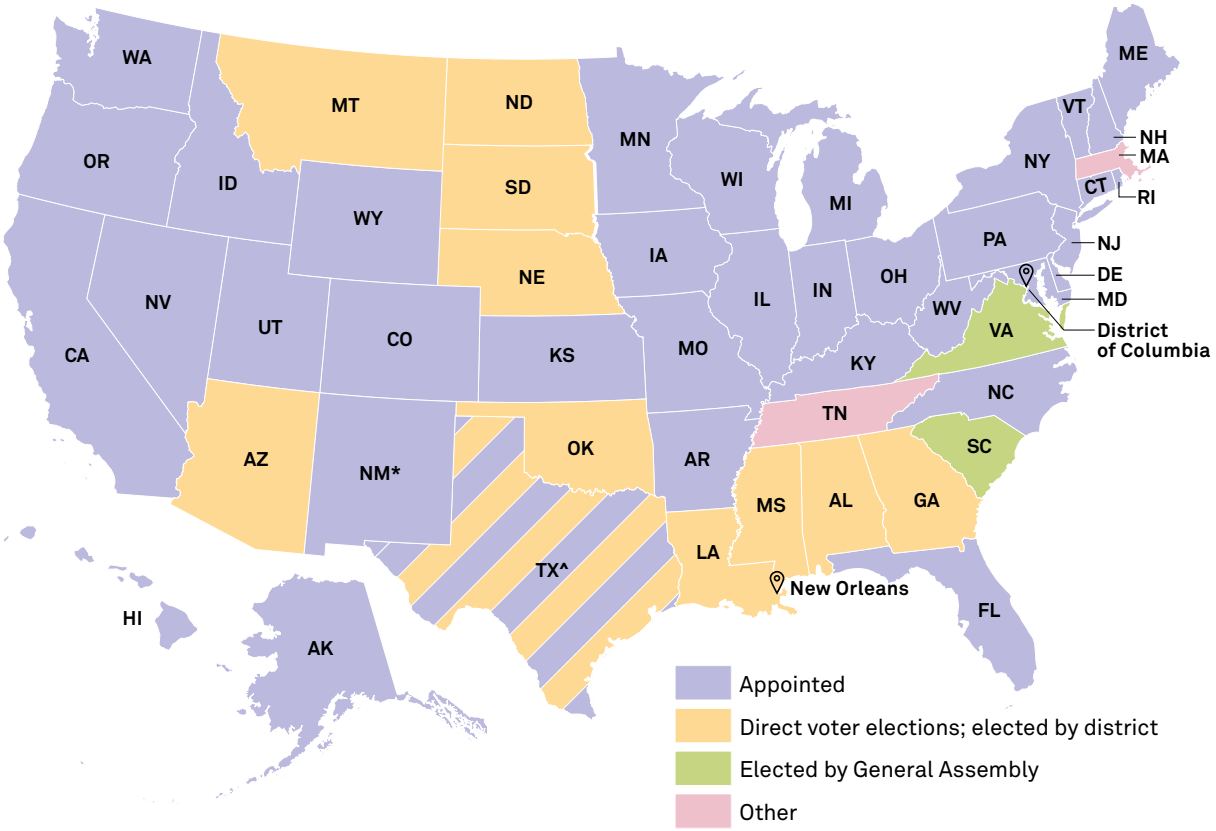
Overview of issues considered in the ranking process

The summaries below provide an overview of the variables RRA looks at, including a brief discussion of how each can impact the ranking of a given regulatory environment.

Governor/Mayor — Actions of the governor (or the mayor in the District of Columbia/City of New Orleans) may impact a jurisdiction's ranking. RRA takes no view on which political party is the more constructive option but does consider to what extent energy issues were of focus of recent elections, whether the governor seeks to become involved in the regulatory process and the type of influence the governor seeks to exert.

Commissioner selection process/membership — RRA examines how commissioners are selected in each state. All else being equal, RRA attributes a greater level of investor risk to states where commissioners are elected rather than appointed. Generally, energy regulatory issues are less politicized when they are not subject to debate in the context of an election.

Commissioner selection methods in US



Data compiled July 31, 2024.
* Prior to Jan. 1, 2023, commissioners were chosen through general elections.
^ The Public Utility Commission of Texas members are appointed by the governor, while members of the Railroad Commission of Texas are elected in statewide elections.
Source: Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Realistically, a commissioner candidate who indicates support for the utilities and their shareholders or appears amenable to rate increases is unlikely to be popular with voters. In addition, there might not be specific experience requirements to run for commissioner, so a newly elected candidate may have a steeper learning curve with respect to utility regulatory and financial issues, which could make discerning the decisions that an individual might make more difficult and could increase regulatory uncertainty.

There have been some notable instances, however, in which energy issues played a key role in gubernatorial/senatorial elections in states where commissioners are appointed, with detrimental consequences for the utilities.

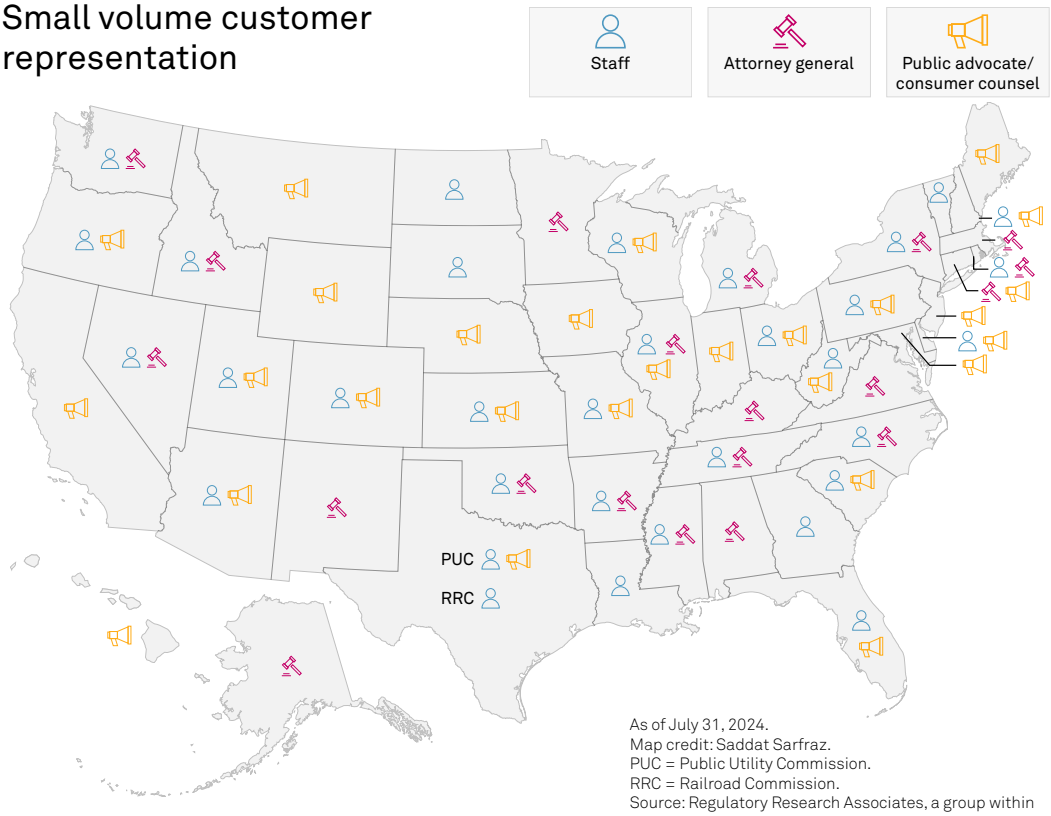
In addition, RRA looks at the commissioners themselves and their backgrounds. Experience in economics and finance and/or energy issues is generally seen as a positive sign. Previous employment by the commission or a consumer advocacy group is sometimes viewed as a negative indicator.

New commissioners with little experience or exposure to utility issues represent the highest level of risk simply because there is no way to foresee their actions or the time they will take to “get up to speed.” Controversy or “scandal” surrounding an individual and/or the potential for a conflict of interest are also crucial factors to consider.

Similarly, a high rate of turnover, extended vacancies, and leaving commissioners serving for a long period of time beyond the end of their terms all add to the level of regulatory risk in RRA's view.

Commission staff/consumer interest — Most commissions have a staff that participates in rate proceedings. The staff may represent the consumer interest, act as advisors to the commissioners or play a less defined role. In addition, there may or may not be additional state-level organizations that are charged with representing the interests of a certain class or classes of customers, such as the attorney general or a consumer advocate, coalitions of cities in which the utility operates, private consortia or lobbying groups that represent certain stakeholder groups and/or large-volume commercial and industrial customers that intervene directly in rate cases.

Small volume customer representation



As of July 31, 2024.
Map credit: Saddat Sarfraz.
PUC = Public Utility Commission.
RRC = Railroad Commission.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Generally, the greater the number of consumer intervenors, the greater the level of uncertainty for investors, as in most instances, the only party representing investors' interests is the company. The level of risk for investors also depends on the caliber and influence of the intervening parties and the level of contentiousness in the rate case process. Even though a commission may not adopt an extreme position taken by an intervenor, the inclusion of an extreme position in the record for the case widens the range of possible outcomes, increasing the risk of a negative outcome for investors. RRA's opinion on these issues is largely based on experience and observations.

Settlements — An increasing number of cases in recent years have been resolved by settlements rather than through a fully litigated process. There are often clear incentives for utilities and entities with vested interests in the sector to compromise. Utilities often obtain settlement benefits in the form of key utility policy objectives and more timely and favorable rate case outcomes than would otherwise be achievable. In some instances, however, settlement negotiations can be protracted and extend the duration of a rate case.

A settlement may set out all of the typical rate case parameters, such as rate of return and rate base, but many are "black box" settlements. These black box settlements are filed when the parties settle all, or nearly all, of their differences in the proceeding, but none of the parties want to disclose the final outcome on a given issue to avoid establishing a precedent.

Or, during settlement discussions, each party may have contemplated a certain revenue change amount as acceptable and may have performed calculations regarding the rate base and rate-of-return parameters behind their revenue requirement positions. Different values for these inputs, however, could be used in varying combinations to determine the same revenue requirement.

All else being equal, the ability of the parties to reach an agreement without having to go through a fully litigated proceeding is considered constructive, particularly since it reduces the likelihood of an after-the-fact court review. However, the agreements are generally less detailed than a fully litigated decision; so, there is a lack of clarity regarding how certain key issues were resolved.

In some instances, the parties may agree on only certain issues and will execute a partial settlement on those issues, while the remaining issues in the case will be litigated.

Rate case timing — For each state commission, RRA considers whether there is a set time frame within which a rate case must be decided, the length of any such statutory time frame and the degree to which the commission adheres to that time frame.

About two-thirds of state commissions nationwide have a rule or statute that requires a rate case to be decided within seven to 12 months of filing; very few have requirements that a case be completed in less than seven months.

Shorter time frames may apply for limited-issue proceedings or if the parties reach an agreement.

RRA generally views a set time frame as preferable, as it provides a degree of certainty as to when any new revenue may begin to be collected. In some states, however, the time frame may be extended with the company's agreement.

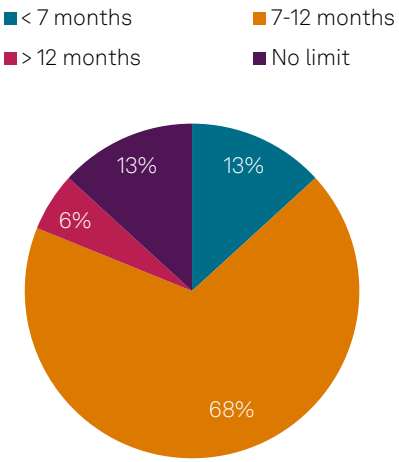
In addition, a shorter time frame for a decision generally reduces the likelihood that the actual conditions, during the first year the new rates will be in effect, will vary markedly from the test period utilized to set new rates, thus keeping regulatory lag to a minimum.

Interim procedures — RRA views the ability to implement all or a portion of a proposed rate increase on an interim basis prior to a final decision as constructive.

In jurisdictions that allow interim rate increases, the utility is required to refund any related over-collections, generally with interest, if the commission approves a rate change that is below the interim rates.

Implementation of an interim increase may be permitted by state law or may require prior approval by the commission, which may not be easy to obtain. Certain states allow a commission to establish an effective date for new rates prior to the final order in the case. The company would then be permitted to recoup any revenue not collected between the effective date and the decision date.

Rate case time frame



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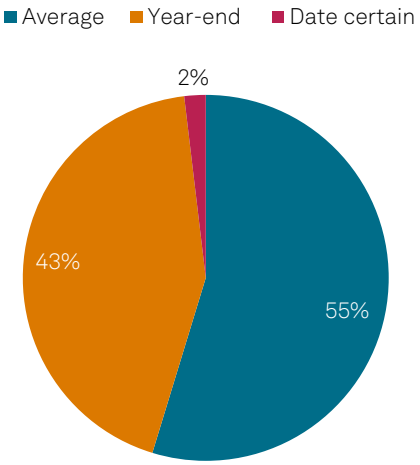
Rate base — A utility's rate base is essentially the company's "prudent" capital investment as determined by the applicable regulatory authorities, net of accumulated depreciation and other adjustments. Rate base is the net asset base of an electric, gas or water utility upon which an allowed rate of return — usually the company's weighted average cost of capital — is applied. The rate base value is a key variable that regulatory bodies use in a rate case to determine a utility's revenue requirement.

A commission's rate base policies can impact a utility's ability to earn its authorized ROE. State statutes often outline these policies, and the commission usually does not have much latitude with respect to these overall policies.

A key factor in assessing whether the company has been accorded a reasonable opportunity to earn the authorized return is the methodology the commission uses to determine rate base.

Commissions are nearly evenly split between those that employ a year-end, or terminal, valuation and those that utilize an average approach, with one using a "date certain" methodology. In some instances, the commission may employ a different rate base valuation method, depending on the utility type or case type or based on the test year selected by the company. For example, a forward-looking test year may be used in a limited-issue rider proceeding or a multiyear rate plan, even though a historical test year is used in traditional single-step base rate cases. Some states allow the utility to choose between a forecast or historical test year but require that an average rate base be used if a forecast test year is requested, while a year-end rate base must be used if a historical test period is selected.

Rate base valuation method



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In general, assuming that rate bases are rising, i.e., new investment is outpacing depreciation, a year-end valuation is preferable from an investor viewpoint.

This again relates to how well the parameters used to set rates reflect actual conditions that will exist during the rate-effective period; hence, the more recent the valuation, the more likely it is to approximate the actual level of rate base being employed to serve customers once the new rates are placed into effect.

Some commissions permit post-test-year adjustments to rate base for 'known and measurable' items. Generally, this practice benefits the utilities when operating costs are rising and/or the company is making significant investments in infrastructure and other capital items.

The rules with respect to what constitutes a known and measurable adjustment, however, are not always specific, and there can be a good deal of controversy about what is and is not acceptable under state law or commission rules.

Another key consideration is whether state law and/or the commission generally permits the inclusion in rate base of construction work in progress (CWIP) for a cash return. CWIP represents assets that are not yet operational but ultimately will serve customers. Some states prohibit the inclusion in rate base of items that are not currently, i.e., during the test year or within a reasonably short period of time following the end of the test year, 'used and useful' in providing service to customers. Thus, CWIP must be excluded.

In these instances, the companies are permitted to accrue allowance for funds used during construction (AFUDC), which is essentially booking a return on the construction investment as a regulatory asset that is recoverable from ratepayers once the project in question becomes operational. While this method bolsters earnings, it does not augment cash flow and does not support credit metrics.

Investors generally view the inclusion of CWIP in rate base for a cash return as constructive since it helps to maintain cash flow metrics during a large construction cycle. In addition, if the company is not able to time its next rate case to coincide with the in-service date of a project, there may be a time period where the plant is operating and, therefore, the company can no longer accrue AFUDC but the utility is incurring operations and maintenance costs and booking depreciation expense, none of which are yet reflected in rates.

This becomes particularly challenging when the utility's construction program consists of several smaller projects with short ramp-up times, making it more difficult for the company to file a case quickly enough to reflect each new project.

Test year — The rate case test year is simply the 12-month period used as a baseline in examining the utility's actual revenues, expenses and rate base. In assessing the level of regulatory risk, RRA examines whether a historical test year is chosen or a future 12-month period with a forecast of the utility's revenues, expenses and rate base.

Almost two-thirds of the 53 jurisdictions covered by RRA utilize a test year that is historical at the time of filing, which increases regulatory lag and uncertainty for investors.

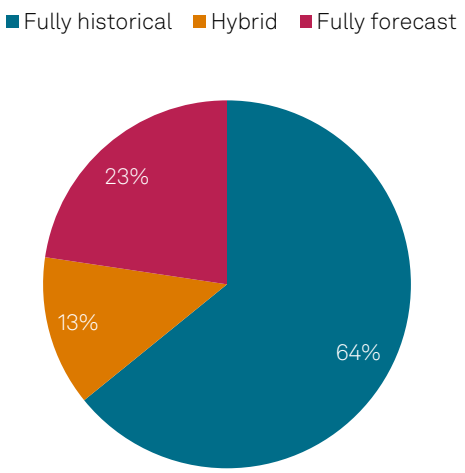
A fully forecast test year is generally considered to be most constructive, particularly in periods of robust capital spending, high inflation and rising interest rates.

Under a hybrid approach, the test year is partially forecast at the time the case is filed but is fully historical by the time the case is decided. The company generally files updates during the proceeding to reflect actual results as they become available.

Some jurisdictions use different test period types for different kinds of proceedings or utilities. For example, the commission may use a historical test year for single-year base rate cases but the use forward-looking test years for multiyear rate cases, alternative regulation plans and/or adjustment clauses.

Many jurisdictions allow for known and measurable adjustments to the test year, but there is considerable variability regarding how far beyond the end of the test year these adjustments may go, and statutes governing the definition of known and measurable can be ambiguous. Consequently, there can be wide disagreement among the rate case parties as to which adjustments qualify.

Rate case test year



Data compiled July 31, 2024.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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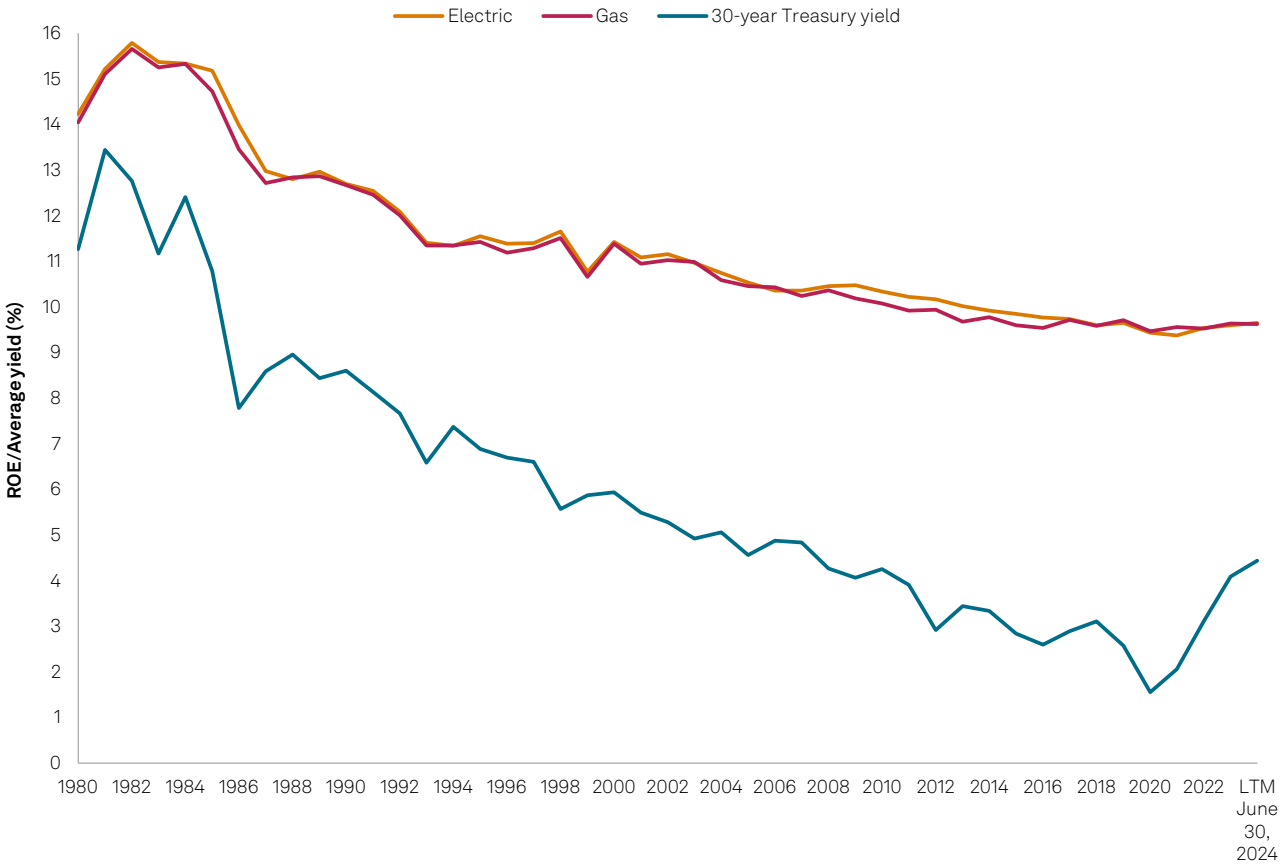
Conversely, in periods where there is only a modest amount of capital spending, i.e., depreciation is outpacing new spending, low inflation and falling interest rates, the use of a historical test year and the associated regulatory lag would work in the utility's favor, as rates would likely reflect higher costs than the utility incurs.

Rate of return — The capital structure, debt cost rates and authorized equity return combine to determine the company's weighted average cost of capital, which is known as the return on rate base in the context of a rate case.

Return on equity (ROE) — The authorized ROE is perhaps the single-most litigated issue in any rate case. Commissions generally rely on financial formulas, such as the discounted cash flow, capital asset pricing model and risk premium approaches, as applied to a proxy group of companies with similar risk characteristics.

Average authorized ROE for US utilities, 30-year Treasury bond yields

Calendar years 1980 - 2023. LTM June 30, 2024



Data compiled July 24, 2024
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
LTE = Last 12 months.
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While these financial models appear objective, there are subjective judgments that go into many aspects of the analysis: the appropriate peer group, the level of risk in the subject company's operations and how it may differ from that of the proxy group and whether there are any other factors that warrant an adjustment to the base calculations.

In establishing rankings, RRA looks at the ROEs historically authorized utilities in a given state and compares them to nationwide industry averages, as calculated in RRA's Major Rate Case Decisions Quarterly Update reports. When referring to these "averages," RRA means the simple average of the ROEs approved in cases decided in a particular period; returns carried over from prior years are not included in the averages.

How the authorized ROEs in a given state compare to prevailing nationwide industry averages is only one aspect of RRA's analysis. Any given utility may be authorized a relatively high ROE, but factors such as the age or "staleness" of the test period, rate base valuation method, adjustments to the company-proposed rate base and expenses, and the way the commission chooses to calculate test year revenue and other adjustments may render it unlikely that the company will earn the authorized return.

Hence, a given rate case decision may be restrictive from an investor viewpoint, even though the authorized ROE is equal to or above the average.

Capital structure — The equity layer in the authorized capital structure is another aspect of a commission rate case decision that may impact the utility's ability to earn the authorized ROE. Most commissions utilize the company's actual capital structure at a given point in time, but in some instances, the commission may rely on an imputed capital structure that represents a mix of debt and equity that the commission views as more reasonable or economically efficient. These are known as hypothetical capital structures.

The commission may include short-term debt and/or other items not generally considered to be part of the utility's cost of capital for financial reporting purposes, such as job development investment tax credits, customer deposits or accumulated deferred taxes (as an alternative to reflecting accumulated deferred tax balances as an offset to rate base). These are generally considered "ratepayer supplied capital" and are accorded a blended cost based on the company's financial weighted average cost of capital or may be assigned a cost rate of zero. Such capital structures are known as regulatory capital structures.

If a commission uses a capital structure that is more highly leveraged than the company's actual structure, this will lower the authorized overall return and the revenue requirement ultimately approved and render it more difficult for the company to earn the authorized return on its actual equity, all else being equal.

Senior capital cost rates — The costs of long- and short-term debt are generally set at the weighted average interest rate on the outstanding issuances. While it is rare, a commission may choose to exclude a recent debt refinancing that alters the company's debt cost rate or may determine that the company was slow to take advantage of opportunities to refinance debt at a lower cost rate. If this occurs, and the senior capital cost rates used to set rates are lower than those that the company will experience while rates are in effect, then the utility will have a more difficult time earning its authorized ROE.

The cost of preferred stock, where there is any, is set based on the guaranteed dividend rate on the outstanding shares.

Accounting — RRA looks at whether a state commission has permitted unique or innovative accounting practices designed to bolster earnings. Such treatment may be approved in response to extraordinary events, such as severe weather events or the COVID-19 pandemic, and changes in federal tax laws, or for volatile expenses, such as fuel and pension costs. Generally, such treatment involves deferral of expenditures that exceed the level of such costs reflected in base rates. In some instances, the commission may approve an accounting adjustment, such as a change in depreciation rates, to temporarily bolster certain financial metrics or to eliminate over-earnings without requiring a full-blown rate case.

Actions taken to address emerging issues and their impact on the utilities are also key. For example, in the wake of the energy transition movement, an increasing number of fossil generation facilities and legacy meters are being retired early. Other types of utility assets are also at risk of becoming "stranded" costs as the transition progresses. In some states, companies have been permitted to accelerate depreciation of certain facilities to complete recovery of the investment prior to an accelerated shutdown of the asset. In others, the utilities are permitted to defer the remaining book value at closure as a regulatory asset that is to be recovered over a period of years; the unamortized balance may or may not be accorded a return.

Alternative regulation — RRA generally views as constructive the adoption of alternative regulation plans that are designed to streamline the regulatory process and accelerate cost recovery or allow utilities to augment earnings in some way. These plans can be broadly or narrowly focused.

Narrowly focused plans may allow the company to retain a portion of cost savings relative to a base level of some expense type (e.g., fuel, purchased power, pension cost, etc.), permit a company to retain a portion of off-system sales revenues for shareholders or provide a company an enhanced ROE for achieving operational performance and/or customer service metrics or for investing in certain types of projects (e.g., demand-side management programs, renewable resources, new traditional plant investment, etc.).

Broad-based plans include ROE-based sharing mechanisms, formula-based rates and MRPs that apply to all cost-of-service issues rather than specific investments or expenses. These types of plans may also include performance-based incentives.

The use of plans with somewhat broader scopes, such as ROE-based earnings-sharing plans, is, for the most part, considered to be constructive, but it depends upon the level of the ROE benchmarks specified in the plan — if any deadband that applies is symmetrical around the ROE target, and whether variations from the benchmark or outside the deadband are shared symmetrically.

Formula-based ratemaking plans generally refer to frameworks where the commission establishes a revenue requirement, including a target ROE, capital structure and rate of return for an initial rate base as part of a traditional cost-of-service base rate proceeding. Once the initial parameters are set, rates may adjust periodically to reflect changes in expenses, revenue and capital investment. These changes generally occur on an annual basis, and there may be limitations on the percentage change that can be implemented in a given year or a period of years.

Others use multiyear rate plans, under which the commission approves a succession of rate changes that are designed to consider anticipated changes in revenues, expenses and rate base. The commission may approve a static authorized ROE, or the plan may provide for adjustments to the ROE during the plan's term. These plans often include true-up mechanisms to ensure that the company makes the investments it committed to at the time the plan was approved. The plans often include earnings-sharing mechanisms and may also include PBR provisions or stay-out provisions, preventing a company from filing a successive rate case until a future point in time.

Court actions — This aspect of state regulation is particularly difficult to evaluate. Common sense would dictate that a court action that overturns restrictive commission rulings is a positive. However, the tendency for commission rulings to come before the courts and for extensive and sometimes protracted litigation as appeals go through several layers of court review may add an untenable degree of uncertainty to the regulatory process. Also, as is the case with commissioners, RRA looks at whether judges are appointed or elected, as political considerations are more likely to influence elected jurists.

Legislation — While RRA's commission profiles provide statistics regarding the makeup of each state legislature, RRA has not found a specific correlation between the quality of energy legislation enacted and the political party controlling the legislature.

If the governor and legislature are of the same political party, it is less likely that controversy will arise around key policy initiatives, which may directly or indirectly impact the energy regulatory framework. In instances where energy issues are a main focus, a lack of consensus between the legislative and executive branches of the state government can create uncertainty and increase risk for utility investors and other industry stakeholders.

Key considerations with respect to legislation include how prescriptive newly enacted laws are; whether the bill is clear or ambiguous and open to varied interpretations; whether it balances ratepayer and shareholder interests rather than only "protecting" the consumer; whether the legislation takes a long-term view or is a "knee-jerk" reaction to a specific set of circumstances; and whether it could constrict the utilities' opportunities to achieve their business objectives.

Legislative activity impacting utility regulatory issues has been robust in recent years as state policymakers, utilities and industry stakeholders seek to address 'disruptors' that challenge the traditional regulatory framework.

RRA follows these developments closely to assess whether the states take a balanced, sustainable approach and how the adopted policies will affect legacy utility providers.

Corporate governance — The term corporate governance generally refers to a commission's ability to intervene in a utility's financial decision-making process through required preapproval of all securities issuances, limitations on leverage in utility capital structures, dividend payout limitations, ring-fencing protocols and authority over mergers. Corporate governance may also include oversight of affiliate transactions.

RRA views a modest level of corporate governance provisions to be the norm, and in some circumstances, these provisions, such as ring fencing, have protected utility investors as well as ratepayers. However, a degree of oversight that would allow the commission to "micromanage" the utility's operations, limit the company's financial flexibility or significantly reduce the company's ability to pursue strategic mergers would be viewed as restrictive.

In recent years, RRA has observed an increasing emphasis on environmental, social and governance issues, and supplier and workforce diversity and social justice issues. In many instances, these policies are part of the ongoing energy transition. At this time, RRA takes no view on whether policymakers/regulators should adopt these practices, but when specific policies or targets are implemented, RRA evaluates how compliance costs are addressed.

M&A activity — The pace of merger activity fluctuates over time and consequently, so does the importance of a commission's merger policies.

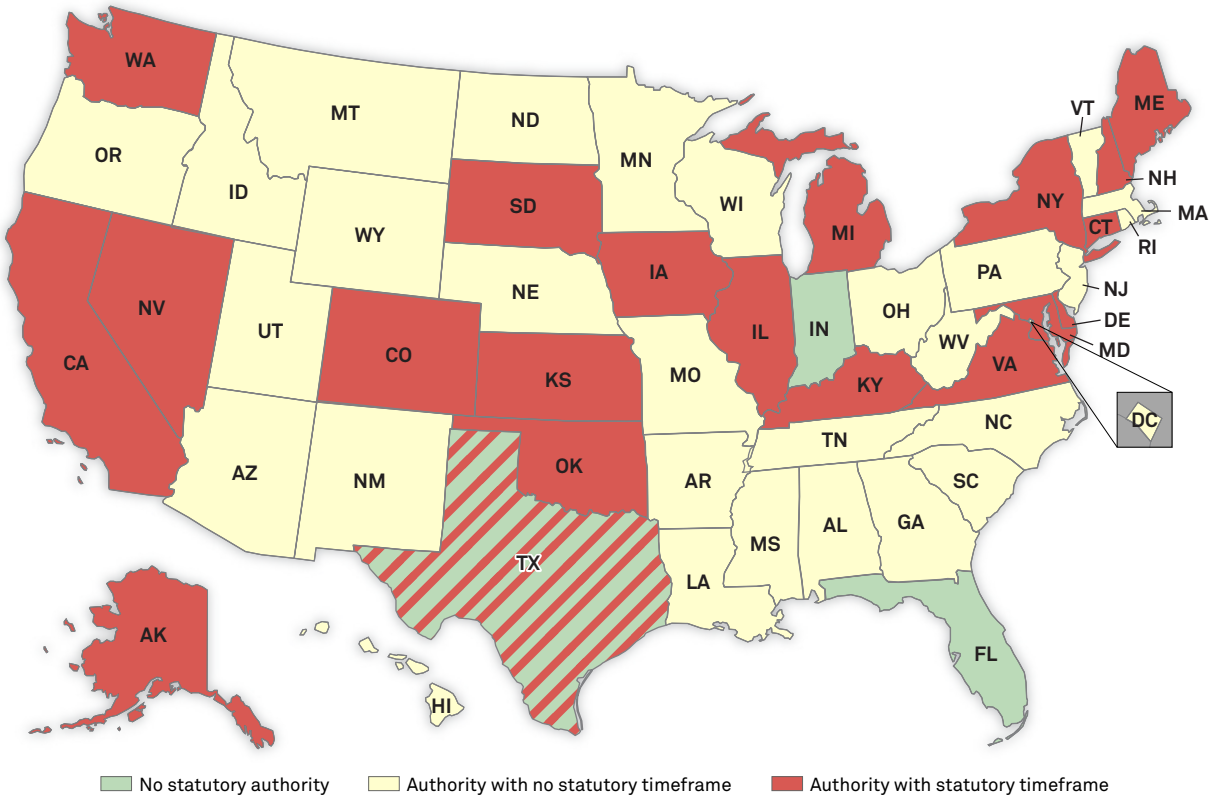
Deals involving regulated utilities are subject to review by all but three of the 53 state-level jurisdictions followed RRA follows.

The review process and standards vary widely for the 50 jurisdictions where commission preapproval is required. In 20 of the jurisdictions, the commission must complete a merger review within a prescribed period, but the remaining jurisdictions have no timeline for their merger reviews, which means a commission could effectively "pocket veto" a transaction by delaying a decision until either the merger agreement between the applicants expires or pursuing the transaction is no longer feasible.

The definition of what constitutes a transaction that is subject to review can vary widely and may include sales of individual assets or a marginal minority interest, as well as larger transactions where a controlling interest or the whole company is changing hands. State law often lacks specificity with respect to what constitutes a transaction that is subject to regulatory review.

In cases where the state commission has authority over mergers, RRA reviews the type of approval standard that is contained in state law and/or has been applied in specific situations.

Utility mergers — statutory authority



As of July 31, 2024.
In Texas, mergers involving electric utilities are subject to commission review; mergers involving local gas distribution companies are not.
Map credit: Arleigh Andes.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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For discussion purposes, RRA groups the statutory standards into three general buckets: public interest, which is generally thought to be the least restrictive; no net ratepayer harm, which is somewhat more restrictive; and net ratepayer benefit, which is the most restrictive.

In many instances, regulators have broad discretion to interpret what the statutes mean by these terms. So, the standard of review is often more readily apparent by looking at how prior transactions were addressed than by reading the statutory language — one commission's public interest might be another's net ratepayer benefit.

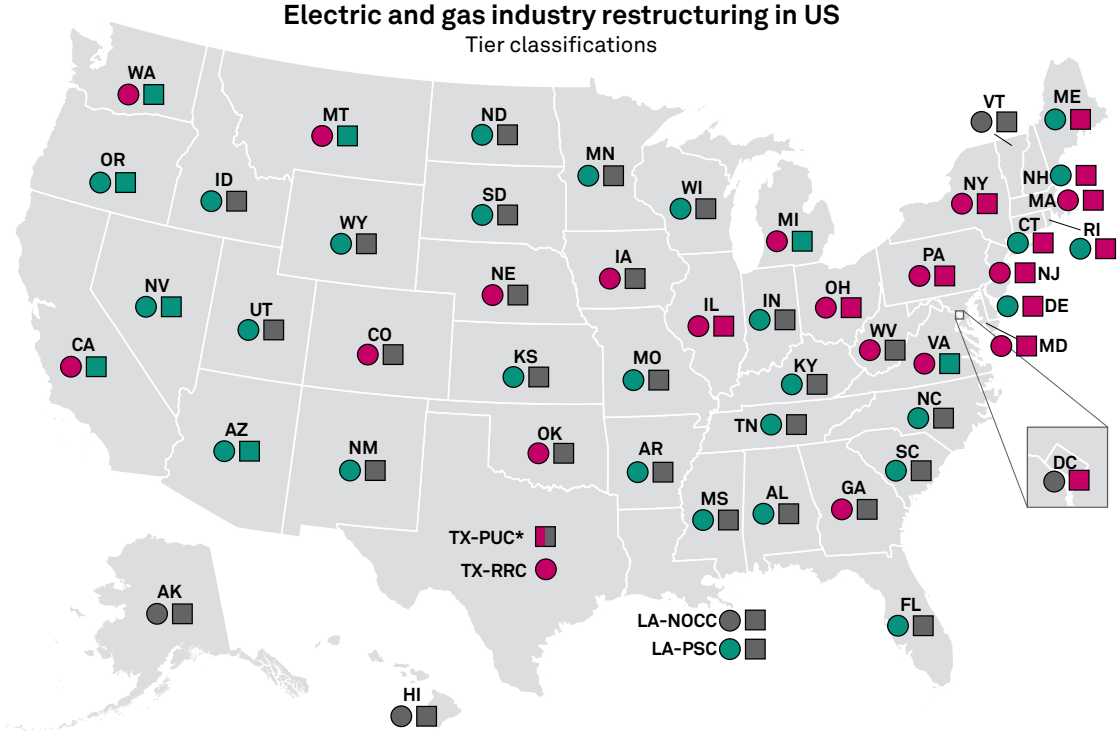
In addition, RRA considers whether the parties reached a settlement and, if so, whether the commission honored that settlement or required additional commitments. RRA also examines how politicized the process was: Did the governor (or the mayor in the District of Columbia and the City of New Orleans) play a role? Did the transaction garner much local media attention in the affected jurisdiction?

More narrowly, RRA reviews the conditions placed on the commission's approval of these transactions, including whether the company will be permitted to retain a portion of any merger-related cost savings, if guaranteed rate reductions or credits are required that are or are not directly related to merger savings, whether certain assets were required to be divested, the type of local control and workforce commitments required, whether there are requirements for certain types of investment to further the state's public policy goals that may or may not be consistent with the companies' business models and if the related costs will be recoverable from ratepayers and whether the commission placed stringent limitations on capital structure and/or dividend policy or composition of the board of directors.

Electric regulatory reform/industry restructuring — Electric industry restructuring refers to the implementation of a framework under which some or all retail customers can obtain their generation service from a competitive supplier of their choice. In a movement that began in the mid-1990s, about 20 jurisdictions implemented retail competition for all or a portion of the customers in the utilities' service territories. The last of the transition periods ended as recently as 2011, when restructuring-related rate freezes concluded for certain Pennsylvania utilities.

Electric and gas industry restructuring in US

Tier classifications



Gas tiers

Tier 1 — All customers are permitted to competitively procure their gas supply, irrespective of volumes.

Tier 2 — Select customers are permitted to competitively procure their gas supply, usually based on volume.

Tier 3 — All customers procure their gas supply from the utility under bundled rates.

Power tiers

Tier 1 — Power prices are competitively determined for all retail customers within the jurisdiction; both standard-offer-service and retail-access customers. Retail access is permitted for all customers.

Tier 2 — Retail access is permitted to at least some customers/customer classes. Competitively priced power is limited to retail access customers. Power prices for standard-offer-service customers remain regulated. For the most part, utilities remain vertically integrated.

Tier 3 — Power prices are fully regulated for all retail customers. All retail customers must purchase their power from the franchised utility. Utiities are vertically integrated.

As of July 31, 2024.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission.
* One in the Electric Reliability Council of Texas territory; three outside of it.
Map credit: Joe Felizadio.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Once the transition periods were completed, RRA focused more on how standard-offer or default service is procured for customers who do not select an alternative provider and how much, if any, market-price risk the utility must absorb. RRA classifies each of the regulatory jurisdictions into one of three tiers based on their relative electric industry restructuring status.

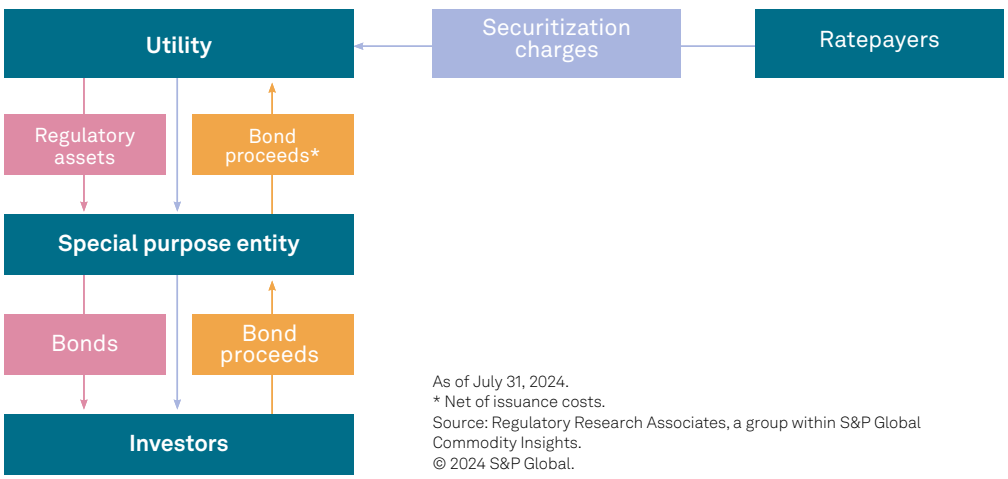
Gas regulatory reform/industry restructuring — Retail competition for gas supply is more widespread than electric retail competition, and the transition was far less contentious, as the magnitude of stranded asset costs was much smaller due to the more disaggregated structure of the industry.

Large-volume customers in most states can select their gas supply provider; the availability of gas customer choice is much more limited for small-volume customers. Like electric retail competition, RRA generally does not view a state's decision to implement retail competition for gas service as either positive or negative from an investor viewpoint. RRA primarily considers how stranded costs are addressed and how default-service, obligation-related costs are recovered.

Securitization — As it pertains to utilities, securitization refers to the issuance of bonds backed by a specific existing revenue stream that regulators and/or state legislators have 'guaranteed.' This does not mean that the securities are backed by the 'full faith and credit' of the jurisdiction but instead provides certainty that the revenue collections and/or underlying assets cannot be deemed imprudent and disallowed in the future.

Securitization generally requires a utility to assign an eligible regulatory asset and a designated revenue stream for that asset to a 'bankruptcy remote' special-purpose entity or trust; in some instances, a state financing authority fulfills this role. The trust or financing authority, in turn, issues bonds that the transferred revenue stream will service. The proceeds from the bond issuance flow to the utility and, in many cases, are used to retire outstanding higher-cost debt and/or buy back common equity, thus lowering the company's weighted average cost of capital.

Securitization flow chart



As of July 31, 2024.
* Net of issuance costs.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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While it is unclear if securitization requires legislation, a specific legislative mandate generally improves the rating accorded securitization bonds and lowers the associated cost of capital, given that a legislatively supported revenue stream may be more difficult to rescind than a stand-alone order of a state commission. In RRA's experience, no state commission has authorized securitization in the absence of enabling legislation.

Securitization is viewed as an attractive option because it allows regulators to minimize the customer rate impacts related to the recovery of a particular utility asset. The carrying charge on the asset would be the lower interest rate applied to a highly rated, usually AAA, corporate bond rather than the utility's weighted average cost of capital or even the interest rate on typical utility bonds, which are generally rated BBB and carry higher interest rates.

At the same time, securitization reduces the investment risk for the utility by providing the utility with up-front recovery of its investment in what are usually non-revenue-producing assets. The company can then redeploy those investment dollars elsewhere.

Securitization has been used for various purposes to finance energy efficiency and conservation investment, address stranded costs associated with the implementation of retail competition or the extension of energy transition policies, reduce the impact on ratepayers of recovery of extraordinary storm costs or unusually high deferred balances or to finance bankruptcy reorganization plans.

Adjustment clauses — Adjustment clauses have been widely utilized to allow utilities to recover fuel and purchased power costs outside of base rate cases, as these costs are generally subject to a high degree of variability. In some instances, a baseline level is reflected in base rates, with only deviations from that amount addressed in the adjustment clause, whereas in others, the entire annual fuel/purchased power cost amount is reflected in the clause.

Over time, the types of costs recovered through these mechanisms were expanded in some jurisdictions to include items such as pension and healthcare costs, demand-side management program costs, Federal Energy Regulatory Commission-approved regional transmission organization costs, new generation plant investment, and transmission and distribution infrastructure spending.

RRA generally views the use of these types of mechanisms as constructive but also looks at the frequency with which the adjustments occur and whether: there is a true-up mechanism; adjustments are forward-looking or based on a historical period; a cash return on CWIP is permitted for mechanisms involving new investments; the mechanism includes an earnings-sharing mechanism that offers the utility upside earnings potential; or incentive(s) for making certain types of investment or for achieving benchmark performance that provide the opportunity to increase earnings.

Another class of adjustment clauses, known as revenue decoupling mechanisms, allows utilities to adjust rates between rate cases to reflect fluctuations in revenues versus the level approved in the most recent base rate case due to various factors.

Some of these factors, such as weather, are beyond a utility's control, and the mechanism can work both ways — it can allow the company to raise rates to recoup revenue losses associated with weather trends that reduce customer usage, and conversely, it can also require the company to reduce rates when weather trends cause usage to be higher than normal.

As energy efficiency initiatives have expanded, decoupling mechanisms have also been implemented to reduce the disincentive for utilities to pursue these types of programs by making the utilities whole for reductions in sales volumes and revenues associated with customer participation.

Some of these mechanisms also allow the utility to adjust rates to reflect fluctuations in customer usage that are brought about by broader economic issues, such as demographic shifts, large commercial/industrial customers migrating to other service areas, businesses shutting down due to changes in their respective industries, recessions and, theoretically, broad-based crises like the COVID-19 pandemic.

RRA considers a decoupling mechanism that adjusts for all three of these factors to be a "full" decoupling mechanism and designates those that address only one or two of these factors as "partial" decoupling mechanisms.

Generally, an adjustment mechanism would be viewed as less constructive if there are provisions that limit the utility's ability to fully implement revenue requirement changes under certain circumstances, e.g., if the utility is earning more than its authorized return or if the adjustment exceeds a certain threshold.

Integrated resource planning — RRA generally considers the existence of a resource-planning process to be constructive from an investor viewpoint, as it may provide the utility at least some measure of protection from hindsight prudence reviews of its resource acquisition decisions. In some cases, the process may also provide for preapproval of the ratemaking parameters and/or a specific cost for a new facility. RRA views these types of provisions as constructive, as the utility can make more informed decisions as to whether it will proceed with a proposed project based on the expected level of support a utility proposal receives from regulators.

Renewable energy/emissions requirements — Goals for renewable energy deployment and emissions reductions have become increasingly intertwined in recent years and often need to be viewed in tandem.

As with retail competition, RRA does not take a stand as to whether the implementation of renewable portfolio standards or an emissions reduction mandate is positive or negative from an investor viewpoint. However, RRA considers whether there is a defined preapproval and/or cost-recovery mechanism for investments in projects designed to comply with these standards.

RRA also reviews if there is a mechanism, such as a rate increase cap, that limits the impact of the related public policy goals on customers. Such a mechanism could impede the utility's ability to recover program-related costs, pursue additional investments and/or recover increased costs related to other facets of its business. RRA also looks at whether incentives, such as an enhanced ROE, are available for these types of projects.

The proliferation of renewables, particularly those that are customer-sited or distributed resources, and the related rise of battery storage and electric vehicles have raised questions regarding the traditional centralized industry framework and whether that framework needs to change, ushering in a second phase of electric industry restructuring. How these changes are implemented is something RRA considers in its rankings.

With respect to emissions, the threat of a federal carbon emissions standard for utilities and the spread of state-level initiatives have caused many companies to rethink legacy coal-fired generation, causing plants to be shut down sooner than anticipated. The way the commissions address these potential stranded costs also poses a risk for investors and is factored into the rankings.

The zero-carbon movement has also caused utilities/states to reexamine investments in nuclear facilities and, in some cases, to develop programs designed to support the continued operation of those facilities, even though they may not be economic from a competitive-market standpoint. RRA also considers the way these issues are addressed.

Rate structure — RRA looks for existing rate structures related to economic development or load retention. If such structures are in place, RRA examines whether and how any associated revenue shortfall is addressed. More broadly, RRA looks at any steps taken in rate cases to reduce/eliminate interclass rate subsidies, i.e., to equalize rates of return across customer classes.

In addition, RRA considers whether the commission has adopted or moved toward a straight-fixed-variable rate design, under which a greater portion of a company's fixed costs are recovered through the fixed monthly customer charge, thus providing the utility greater certainty of recovering its fixed costs.

This is increasingly important in an environment where weather patterns are more volatile, energy efficiency/conservation programs proliferate and large amounts of nonrevenue-producing capital spending are required to upgrade and harden the grid.

In conjunction with the influx of renewables and distributed generation, issues surrounding the level of compensation owed to customer-owners for excess power they put back into the grid have become increasingly important and, in some instances, controversial. The way these pricing arrangements, known as net metering, are structured can impact the ability of the utilities to recover their fixed distribution system costs and, by extension, their ability to earn their authorized returns.

RRA also looks at whether the state has implemented policies to address electric vehicle charging and time-of-use rates, as well as tariffs for renewable natural gas.

Fixed vs. variable costs

Fixed	Variable
Depreciation	Gas commodity
Delivery O&M	Electric commodity
Property taxes	Generation O&M
Return on investment	
Customer service	

Data compiled as of July 31, 2024
O&M=operations and maintenance.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Further Reading

Jurisdictions with ranking changes

New investment rider among key aspects of case ruling for Arizona Public Service

Evergy-backed cost recovery bill approved by Kan. state House

ONE Gas Kan. utility backs condensed performance-based approach to ratemaking

NorthWestern files Mont. rate cases to address $1B of capital expenditures

Parties recommend significant disallowances in Chesapeake's Md. rate case

Md. regulators reject Exelon multiyear plan, opt for one-time rate increase

Md. governor to consider handful of energy bills as legislative session ends

Mich. commission staff supports smaller electric rate increase for DTE Energy

Mich. regulators adopt settlement, pare back rate increase for Consumers Energy

Mich. regulators halve electric rate request by Indiana Michigan Power

Recent developments signal shifts in energy regulatory climate in 2 states

Jurisdictions to watch

Ariz. regulators focus on renewables, test years, other varied issues

Decision on tap in Avangrid's Conn. gas rate cases

Iberdrola deal to buy rest of Avangrid to face some regulatory scrutiny

United Illuminating files brief urging court to reverse negative rate decision

Conn. lawmakers look to update state climate goals, study gas phaseout options

Commonwealth Edison seeks to address regulatory uncertainty with new grid plan

With new grid plan filing, Ameren seeks to assuage commission's prior concerns

Commission to resolve post-hearing issues in Alliant's Iowa base rate case

Alliant's Iowa settlement includes 5-year electric rate increase moratorium

Black Hills Iowa Gas requests $20.7M rate hike for capex, higher operating costs

Rider risk profile a prominent focus in Columbia Gas' Ky. rate change request

Elizabethtown Gas files 1st rate case since acquisition by infrastructure fund

Okla. commission staff concerned with AEP utility's rider, tree trimming plans

Okla. commission staff criticizes vegetation management practices at OGE utility

Parties reach unopposed settlement in AEP Texas rate case

Settlement talks begin in CenterPoint's Texas rate case amid storm controversy

Texas governor appoints consumer advocate to PUC

Wyo. consumer advocate seeks additional conditions in Enbridge-Dominion deal

Low-carbon standard, rates, reliability top list for Wyo. lawmakers

Industry trends

Energy authorized returns edge higher in H1 2024

First-half 2024 utility rate requests above average but trail 2023's record

Flurry of energy rate case activity underway in US

Utility capex primed for profusion in 2024 and beyond

RRA reference reports

Demystifying rate base mechanics can be instructive for industry practitioners

Understanding main aspects of case process empowers utility sector participants

For detailed information about each jurisdiction's policies and regulatory ranking, visit the Commissions page on S&P Capital IQ Pro.

For a full listing of past and pending rate cases, rate case statistics and upcoming events, visit the Energy Research Home Page on S&P Capital IQ Pro.

For a complete, searchable listing of RRA's in-depth research and analysis, please go to the Energy Research Library S&P Capital IQ Pro.

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About Regulatory Research Associates

Regulatory Research Associates, a group within S&P Global Commodity Insights, is the leading authority on utility securities and regulation. Understanding the financial and strategic impact of federal and state regulation is a key to success in the energy business. For more than 40 years, Regulatory Research Associates has been the leading provider of independent research, expert analysis, proprietary data and consultation on utility securities and regulation. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

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UBS

Global Research and Evidence Lab
10 May 2023

US Utilities

Pricing Power Analysis and Regulatory Rankings

Equities

Americas

Utilities

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Updated Regulatory Rankings

We have updated the regulatory rankings of the 58 jurisdictions in North America across five Tiers (Tier 1 is most constructive, Tier 5 is least constructive). See Figure 3. We rate the jurisdictions using seven criteria. We believe constructive regulation provides a positive feedback loop of consistent and fair outcomes for investors, that also results in better customer service and satisfaction, which is what regulators want to see to constructively regulate. Jurisdictions that moved up are AL, ID, and PA (to Tier 1 from Tier 2), CA, MO, and ND (to Tier 2 from Tier 3), and NY (to Tier 4 from Tier 5). We would also note that while LA remained in Tier 3 it moved up significantly from the bottom to the top of that Tier. Jurisdictions that moved down are IN and MI (to Tier 2 from Tier 1), AK (to Tier 4 from Tier 3), and DC, MS, and NM (to Tier 5 from Tier 4).

Lower Relative Pricing Power a Risk to Regulation and Growth

Our pricing power analysis tends to point to where regulatory strain or growth pressures may develop. We saw this last year when our metric showed lower relative pricing power for EXC, PEG, NI, EMA, D, PCG, WEC, and NEE. Most either lowered or rebased their growth - EXC, PEG, and NI; or, faced material regulatory headwinds - EMA and the rate cap legislation in NS, and D with the overall strategic review and legislation in VA reworking the regulatory construct. For WEC, although the rate case outcome was constructive in WI, the rhetoric during the hearing was not encouraging. Where pricing power did not pressure regulation or earnings growth was for NEE and PCG. We rank FL as the most constructive regulatory jurisdiction in North America and NEE's rates at FPL are set through 2025. We also believe CA regulation is increasingly constructive around wildfire and clean energy policy goals, as evidenced by the move to Tier 2 in this year's jurisdiction rankings. Companies that show lower relative pricing power in our updated analysis that did not in May 2022 are AES, CMS, CNP, DTE, ED, ES, and EVRG. Of these names we are Buy rated on AES mainly for the unregulated story, and CNP, where we think significant customer growth in TX can help alleviate pricing pressures. We are Neutral on the remaining names with lower pricing power in '23 vs. '22 and remain diligent in watching regulatory processes in MI for CMS and DTE, in CT for ES, and in KS for EVRG as well as policy in NY for ED. Names that showed continued lower relative pricing power in '23 vs. '22 are D, EXC, NI, PEG, and WEC where D, EXC, NI, and PEG have either gone into or completed a strategic review and/or lowered/rebased their growth rates. WEC remains in a Tier 1 regulatory jurisdiction in WI, but the LNT rate case in that state, as well as WEC's gas case in IL are worth watching.

Updated Pricing Power Analysis - Affordability Inflation vs. Growth

Our analysis places the group across one of four quadrants, although a little more than half of companies are clustered around the combined medians (see Figure 1). We have overlayed the weighted average regulatory ranking quartile of each company on this matrix indicated by color as noted. Those companies outside the median zone in one of the four quadrants are: (I) Pricing power with lower costs or higher weighted average disposable income growth: PCG, PPL, and SO; (II) Lower pricing power, requiring constructive regulation to maintain growth: AES, CMS, CNP, EXC, ES and NI; (III) Lower pricing power that would require constructive regulation or policy support to accelerate growth: D, DTE, ED, EVRG, PEG, and WEC; (IV) Pricing power and opportunity to accelerate growth if regulation is constructive: EIX, OGE, and PNW.

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ANALYSIS OF PRICING POWER IN REGULATED UTILITIES

Given investor focus on inflation and its potential impacts, and the potential for accelerating capital expenditures and rate base growth into the clean energy transition (Cap-Ex Update: Breakthroughs in Spending, 30 March 2023) we analyzed the "pricing power" of regulated utilities. Instead of just a straight analysis of annual increases in bills, we took the estimated bill increase divided by the weighted average personal income by jurisdiction for each company. We then estimated the total increase in that metric through 2029 and annualized that number. We believe this is a more accurate representation of "pricing power" for a utility as it takes into account the relative affordability of the projected bill increases across the relative incomes of the customer base across a company's jurisdictions.

To calculate bill inflation, we used each company's projected capital plan and extended that at flat capex to 2029 from the end of each company's forecast to determine rate base growth. For fuel expenses, we used forward curves and retired all coal generation by 2028 and replaced it with a third each of solar, wind, and natural gas. We incorporated non-fuel O&M increases of 2%/year, held interest expense at 5.5%, used 30-year depreciation, and an allowed return of 10.2% and a 48% equity ratio. While individual companies may achieve better or worse metrics, we tried to create an average metric across companies over the eight-year time frame. Retail sales growth averaged approximately 1% per year.

To calculate disposable income, we took each state or province's disposable income in 2021 and grew it by forecast gross state or provincial product through 2025 and then held annual gross state or provincial product growth constant through 2029. For each company we weighted this by earnings power by jurisdiction to estimate the weighted average disposable income.

Dividing annual bills by weighted average disposable income projected into 2029 and seeing how much that grew versus the same metric in 2021, and annualizing that growth provides a measure of bill affordability inflation. When we graph this against annualized projected utility and parent only EPS growth, the results are shown in Figure 1 below. We have also overlayed the weighted average regulatory ranking quartile onto this graph through the color of the dots: 1st quartile is green, 2nd quartile is blue, 3rd quartile is yellow, and 4th quartile is red. This relative regulatory quartile is important, as more constructive regulation will likely allow for more EPS growth with more affordability inflation, all else equal.

In Figure 1, about half of the companies end up around the median level of growth and affordability inflation of ~6.3% and just under 1%, respectively. Those outside of the median grouping end up in one of four quadrants: (I) high growth and low affordability inflation - where there is clear pricing power due to lower cost structures or higher disposable income growth; (II) high growth and higher affordability inflation, where pricing power needs to be maintained by constructive regulation or policy support to maintain growth; (III) lower growth and higher affordability inflation - where there is lower relative pricing power and it would require constructive regulation or, more likely a state or provincial energy policy initiative to accelerate growth above the median, and (IV) low growth and low affordability inflation - where there is an opportunity to accelerate growth if regulation is constructive or where a company might get stuck at lower than median growth if regulation is more challenging.

Our pricing power analysis tends to point to where regulatory strain or growth pressures may develop as we saw last year when our metric showed lower relative pricing power for EXC, PEG, NI, EMA, D, PCG, WEC, and NEE. Most either lowered or rebased their growth - EXC, PEG, and NI or faced material regulatory headwinds - EMA and the rate cap legislation in NS; D with the overall strategic review and legislation in VA reworking the regulatory construct. For WEC although the rate case outcome was constructive in WI the rhetoric during the hearing was not encouraging. Where pricing power did not pressure regulation or earnings growth was for NEE and PCG. We rank FL as the most constructive regulatory jurisdiction in North America and NEE's rates at FPL are set through 2025. We also believe CA regulation is increasingly supportive around wildfire and clean energy policy goals, as evidenced by the move to Tier 2 in this year's jurisdiction rankings. Companies that show lower relative pricing power in our updated

analysis that did not in May 2022 are AES, CMS, CNP, DTE, ED, ES, and EVRG. Of these names we are Buy rated on AES mainly for the unregulated story, and CNP, where we think significant customer growth in TX can help alleviate pricing pressures. We are Neutral on the remaining names with lower pricing power in '23 vs. '22 and remain diligent in watching regulatory processes in MI for CMS and DTE, in CT for ES, and in KS for EVRG as well as policy in NY for ED. Names that showed continued lower relative pricing power in '23 vs. '22 are D, EXC, NI, PEG, and WEC where D, EXC, NI, and PEG have either gone into or completed a strategic review and/or lowered/rebased their growth rates. WEC remains in a Tier 1 regulatory jurisdiction in WI, but the LNT rate case in that state, as well as WEC's gas case in IL are worth watching.

Figure 1: EPS Growth vs. Affordability Inflation May 2023



Source: Company filings, FactSet, S&P Global Market Intelligence, UBS Equity Research estimates

NOTES:

Wtd. Avg. Regulatory Rank in indicated by color. Green is 1st quartile, Blue is 2nd quartile, Yellow is 3rd quartile, and Red is 4th quartile.

Bill inflation is calculated as the increase in annual bills/disposable income, annualized. Disposable income is grown at state forecast GDP, and a weighted average is taken by company.

Figure 2: EPS Growth vs. Affordability Inflation May 2022



Source: Company filings, FactSet, S&P Global Market Intelligence, UBS Equity Research estimates

NOTES:

Wtd. Avg. Regulatory Rank in indicated by color. Green is 1st quartile, Blue is 2nd quartile, Yellow is 3rd quartile, and Red is 4th quartile.

Bill inflation is calculated as the increase in annual bills/disposable income, annualized. Disposable income is grown at state forecast GDP, and a weighted average is taken by company.

UPDATED REGULATORY RANKINGS

We are updating our jurisdictional regulatory rankings which we do approximately every 6 months. Our last update was in November 2022 Shifting Reguatory and Growth Quartiles.

We rate the jurisdictions using seven criteria. We believe that constructive regulation provides a positive feedback loop of consistent and fair outcomes for investors, that also results in better customer service and satisfaction, which is what regulators want to see to constructively regulate. At the bottom of Figure 3 we show the average JD Power Customer Service scores, which are mostly consistent with our tiered rankings. Those jurisdictions highlighted in green moved up, and those highlighted in red moved down versus our previous rankings. As a reminder the table reads as an ranking histogram so Florida in Tier 1 is more constructive than British Columbia in Tier 1, and so on.

Figure 3: UBS North America Jurisdictional Regulatory Rankings

UBS REGULATORY JURISDICTION RANKINGS - May 2023 Update

TIER 1	TIER 2	TIER 3	TIER 4	TIER 5
		New Jersey		
		Louisiana		
		Massachusetts		
		Oregon		
		South Carolina		
		Tennessee		
	Arkansas	Washington		
Florida	Indiana	Newfoundland & Labrador	Rhode Island	Alberta
British Columbia	Kentucky	Ontario	Nova Scotia	District of Columbia
North Carolina	Michigan	Virginia	West Virginia	Mississippi
Utah	California	Wyoming	Alaska	New Mexico
Wisconsin	FERC	Ohio	Kansas	Connecticut
Iowa	Missouri	Oklahoma	Minnesota	Maine
Alabama	North Dakota	Texas	Nevada	Montana
Georgia	Colorado	Maryland	New Hampshire	South Dakota
Idaho	Delaware	Prince Edward Island	Nebraska	Vermont
Pennsylvania	Illinois	Hawaii	New York	Arizona
JD Power Average Customer Service Scores				
751	718	727	717	719

Source: S&P Capital IQ Pro, FactSet, JD Power, UBS Equity Research

NOTES: Green indicates moved up a Tier since last rankings, Red indicates moved down a Tier. LA is highlighted given it moved significantly within Tier 3 since the last rankings

The ranking criteria are as follows:

1) Elected vs. Appointed Commissions: Elected commissioners tend to focus more closely on managing customer affordability which can dampen investment vs. appointed commissions that tend to be more policy driven, all else equal.

2) Tendency to Settle vs. Litigate Rate Cases: Settlements have the advantage of being quicker, less risky and less prone to legal appeal than fully litigated rate proceedings. States that regularly settle are preferred by investors.

3) Regulatory Lag: Regulatory lag is the difference between authorized returns on equity and earned returns resulting from time lag between dollars invested in rate base and authorized revenues reflecting that spending. We rank regulatory lag based on the time it takes to reach a decision in rate cases.

4) Rate and Customer Bill Levels: Utilities' prices are often a material factor in state economic development. States with high prices versus their surroundings tend to scrutinize utility investment more closely than states with low bills. We look at the average rate and the average residential bill.

5) Allowed Return Spread: We measure the return spread over 10-year Treasury note of the ordered rate cases since 2010 by jurisdiction. As rate of return setting policies and practices are grounded in decades of case law, jurisdictions that allow high and low return spreads tend to continue with that practice.

6) Regulatory Mechanisms: We include an average of eight mechanisms. These include things like tracking mechanisms, forward test years, formula rate plans, and performance based regulation.

7) UBS Subjective Investor Friendliness Factor: Based on our knowledge of current commission actions.

Biggest Changes to the State Rankings

With this review we highlight the largest positive and negative ranking votes out of 58 total jurisdictions we are covering in the United States and Canada:

Positive Changes

- Alabama. Constructive tracking mechanisms, high ROE spreads, and lower relative rates moved the state into Tier 1 relative to other jurisdictions.
- Idaho. Continued low rates moved the jurisdiction into Tier 1 relative to other jurisdictions.
- Pennsylvania. Relative improvement given other states fell to Tier 2.
- California. Regulatory lag improved from 5th quintile to 4th which moved the state from the top of Tier 3 in our May 2022 analysis into Tier 2.
- Missouri. Regulatory lag improved from 3rd quintile to 2nd, moving the state to Tier 2 from near the top of Tier 3 in our prior analysis.
- North Dakota. Settlements became more common, and historical ROE spread improved to 2nd quintile from 3rd quintile, offset slightly by regulatory lag increasing, moving to the 4th quintile from the 3rd.
- Louisiana. Did not move out of Tier 3, however did have a significant move worth highlighting from the bottom to the top of that Tier. ROE spread to the 10 year improved and it moved to 2nd quintile from 4th in that category.
- New York. Settle vs. Litigate improved to 1st quintile from the 2nd.

Negative Changes

- Indiana. Cost to customers got a bit worse with a move to the 3rd quintile from the 2nd which was enough to move the state to Tier 2 from the bottom of Tier 1 in May 2022.
- Michigan. ROE spread to the 10 year came in to 3rd quintile from 2nd, and we moved our subjectiveness ranking to 2nd quintile vs. 1st quintile.
- Alaska. Moved lower as other states moved higher so lost relative positioning into Tier 3
- District of Columbia. Lower rate of settlements, 5th quintile ROE spreads, and 4th quintile regulatory lag pushed this jurisdiction to the top of Tier 5 relative to other jurisdictions from the bottom of Tier 4 in May 2022.
- Mississippi. Elected commission with higher relative costs to customers average regulatory lag, and 5th quintile ROE spreads versus risk free rates, pushed this state into Tier 5 relative to other jurisdictions.
- New Mexico. Was at the bottom of Tier 4 in our May 2022 analysis and was a relative mover to Tier 5 as New York improved into Tier 4.

Valuation Method and Risk Statement

North America Utilities: Our valuation methodology for the group is price to earnings based. The adjustments applied fall into 7 categories. These are as follows: 1) Group Valuation Bias: Flowing from our valuation work comparing Baa corporate yields to group dividend yields and RU price to earnings ratios to those for the S&P 500, we incorporate a positive or negative adjustment to our group multiple representing the gap we calculate to the nearest 5%; 2) Growth Adjustment: We adjust our valuations based on the growth quartile each utility occupies. First quartile receives a 4% premium, second quartile a 2% premium, third quartile a 2% discount and fourth quartile a 4% discount; 3) Regulatory Adjustment: Our valuation adjustments for regulation are based on our proprietary Regulatory Rankings. First quartile jurisdictions receive 10%, second quartile 5%, third quartile -5% and fourth quartile -10%; 4) Clean Energy Transition: A potential 5% premium for a risk adjusted clean energy transition growth opportunity; 5) Earnings Consistency Adjustment: For companies that fall in the top quartile of % Time Beat/Meet, we include +4%; 6) Multi Utility Diversified Valuation: For multi utilities (those with more than 15% of unregulated earnings), we perform a sum-of-the-parts analysis applying business/region appropriate valuations to those diversified businesses; 7) One-off Adjustments: In special situations, we value risk on an issue-specific basis. Common areas where we apply such an adjustment include: large project construction risk, legal risk, and announced M&A completion risk. We identify the following risk factors: rising interest rates; regulatory and policy risks; operational risks; construction risks; cybersecurity risk to the transmission grid and/or customer data, and extreme weather events.

IPPs: Our valuation methodology is based on mid-cycle EV/EBITDA multiples of 7.1x.

CEG: Our valuation methodology is based on an infrastructure comp on EV/EBITDA.

Water Utilities: Our valuation methodology for the group is price-to-earnings based. Our methodology includes: 1) Growth Adjustment: We adjust our valuations based on the growth quartile each utility occupies. First quartile receives a 4% premium, second quartile a 2% premium, third quartile a 2% discount and fourth quartile a 4% discount; and 2) Regulatory Adjustment: Our valuation adjustments for regulation are based on our proprietary Regulatory Rankings. First quartile jurisdictions receive 10%, second quartile 5%, third quartile -5% and fourth quartile -10%.

North American utilities: We identify the following risk factors for the sector overall: rising interest rates; regulatory and policy risks; operational risks; construction risks; cybersecurity risk to the transmission grid and/or customer data, and extreme weather events.

IPPs: We identify the following risks for the sector: Power prices, fuel prices, capacity prices, supply and demand for electricity, extreme weather, economic conditions, and cost of financing and collateral hedging.

CEG: We identify the following risks for CEG: Power price volatility above the nuclear PTC price, uranium fuel prices, supply and demand for electricity, cost of financing and nuclear operational risk.

Water Utilities: We identify the following risks: rising interest rate; regulatory and policy risks; operational risks; construction risks; water quality, safety and contamination risk; physical risk to the water sources, treatment or delivery systems; cybersecurity risk; drought and extreme weather events.

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12-Month Rating	Definition	Coverage[1]	IB Services[2]
Buy	FSR is > 6% above the MRA.	54%	22%
Neutral	FSR is between -6% and 6% of the MRA.	36%	21%
Sell	FSR is > 6% below the MRA.	10%	18%
Short-Term Rating	**Definition**	**Coverage[3]**	**IB Services[4]**
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 31 March 2023.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

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UBS Securities LLC: Gregg Orrill, Ross Fowler, CFA, William Appicelli, CFA.

Company Disclosures

Company Name	Reuters	12-month rating	Price	Price date
AES Corp[16]	AES.N	Buy	US$21.71	08 May 2023
Alliant Energy Corp[16]	LNT.O	Neutral	US$54.76	08 May 2023
Ameren Corp[16]	AEE.N	Neutral	US$89.14	08 May 2023
American Electric Power Inc[16,7,6b]	AEP.O	Buy	US$92.14	08 May 2023
CMS Energy Corp[16]	CMS.N	Neutral	US$61.19	08 May 2023
CenterPoint Energy Inc[16]	CNP.N	Buy	US$30.25	08 May 2023
Consolidated Edison Inc[16]	ED.N	Neutral	US$99.01	08 May 2023
DTE Energy Co[16]	DTE.N	Neutral	US$113.00	08 May 2023
Dominion Energy Inc[16,7,6b]	D.N	Neutral	US$56.50	08 May 2023
Duke Energy Corp[16,7,6b,6c]	DUK.N	Neutral	US$98.90	08 May 2023
Edison International[16]	EIX.N	Buy	US$73.39	08 May 2023
Emera Inc	EMA.TO	Buy	C$58.95	08 May 2023
Entergy Corp[16,7,6b,6c]	ETR.N	Neutral	US$106.91	08 May 2023
Evergy, Inc[16]	EVRG.O	Neutral	US$62.05	08 May 2023
Eversource Energy[16,7,6b]	ES.N	Neutral	US$76.75	08 May 2023
Exelon Corp[16,7,6b,6c]	EXC.O	Buy	US$42.77	08 May 2023
FirstEnergy Corp[16]	FE.N	Buy	US$39.09	08 May 2023
Fortis Inc[16]	FTS.TO	Sell	C$61.27	08 May 2023
NextEra Energy Inc[2,4,5,16,7,6a]	NEE.N	Buy	US$76.06	08 May 2023
NiSource Inc.[16]	NI.N	Neutral	US$28.45	08 May 2023
OGE Energy Corp[16]	OGE.N	Neutral	US$37.55	08 May 2023
PG&E Corp[16,7,6b,6c]	PCG.N	Neutral	US$17.41	08 May 2023
PPL Corp[16]	PPL.N	Buy	US$28.59	08 May 2023
Pinnacle West Capital Corp[16,7,6b]	PNW.N	Sell	US$79.82	08 May 2023
Public Service Enterprise Group[16,7,6b]	PEG.N	Buy	US$63.49	08 May 2023
Sempra[16]	SRE.N	Buy	US$154.93	08 May 2023
Southern Co[13,16]	SO.N	Buy	US$74.57	08 May 2023

Company Name	Reuters	12-month rating	Price	Price date
WEC Energy Group Inc[16]	WEC.N	Neutral	US$95.03	08 May 2023
Xcel Energy Inc[16]	XEL.O	Neutral	US$69.32	08 May 2023

Source: UBS. All prices as of local market close. Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date.

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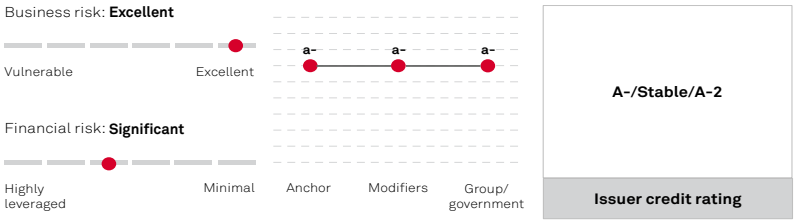
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Consumers Energy Co.

September 15, 2025202x

This report does not constitute a rating action.

Ratings Score Snapshot



Credit Highlights

Overview

Key strengths	Key risks
Monopolistic vertically integrated electric utility and gas distribution utility operations.	Lack of operating diversity that makes the company largely depend on Michigan regulators to sustain its credit quality.
Favorable regulatory construct in Michigan.	A 2024 third-party audit that indicated below-average system reliability as measured by system and customer average interruption indices.
Large customer base of 1.9 million electric and 1.8 million gas customers.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.
Insulated subsidiary of its parent, CMS Energy Corp., allowing us to rate it one notch above the parent.	Susceptibility to adverse weather events, including winter and convective storms.
	Exposure to cyclical commercial and industrial customers, which account for 45%-50% of electric utility revenues and 20%-25% of gas utility revenues.

We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk. We believe Michigan's regulatory construct is above average compared with peers because of the benefit of a streamlined 10-month rate case process. Other constructive rate mechanisms

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include the use of forward test-years, power supply cost rider adjustments, and natural gas cost rider adjustments. These mechanisms help the company earn its allowed return on equity (ROE) and minimize regulatory lag.

CE is currently seeking rate increases in both electric and gas businesses. In June 2025 CE filed for a $460 million electric rate increase, based on a 10.25% ROE (previously approved 9.9%) and an equity layer of 42.94% (previously approved 41.73%). Separately, CE is seeking a $217 million rate increase in its gas business. This is premised on a ROE of 10.25% (previously approved 9.9%) and an equity layer of 42.58% (previously approved 41.48%).

We continue to monitor related developments. We will also continue to monitor the company's performance in light of a 2024 third-party audit which indicated a below-average system reliability assessment for CE as measured by system and customer average interruption indices.

Table 1

Consumers Energy Co. rate-case details

	Electric rate case		Gas rate case	
	Present case: Requested by CE 6/2/2025	Previous case: Authorized by MPSC 3/21/2025	Present case: CE revised request 6/25/2025	Previous case: Authorized by MPSC 7/23/2024
Rate change amount (mil. $; excluding deferrals)	438.8	153.8	217.1	35.0
Return on equity (%)	10.25	9.90	10.25	9.90
Common equity to total capital (%)	42.94	41.73	42.58	41.48

MPSC--Michigan Public Service Commission. N.A.--Not available. Sources: Company, S&P Capital IQ Pro.

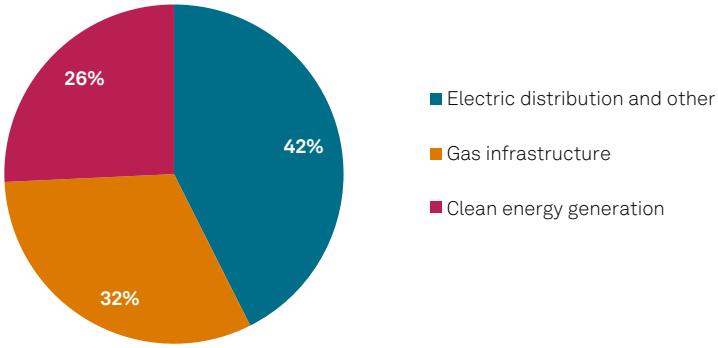
The company's elevated capital spending plan prioritizes infrastructure upgrades and its energy transition plans. Over the next five years, CE plans to invest $20 billion to maintain and upgrade its electric distribution systems and gas infrastructure, as well as reduce its carbon emissions. This includes $8.5 billion for electric distribution upgrades--such as strengthening circuits, replacing poles, and connecting clean energy sources--and $6.3 billion for gas infrastructure improvements to enhance safety, sustain deliverability, and cut methane emissions. Additionally, $5.2 billion will fund clean generation investments in wind, solar, and hydroelectric resources.

The company also intends to reduce its carbon exposure in line with its Integrated Resource Plan (IRP), which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 and a goal to retire CE's owned coal-fired generation plants in 2025. However, on June 1, 2025, the US Department of Energy (DOE) ordered CE to extend the retirement of its coal fired J.H. Campbell power plant by 90 days. Furthermore, the company's IRP targets a gradual reduction in its gas-fired generation dependence after 2025. The company has also announced a net-zero greenhouse gas emissions target by 2050 and a zero-methane emissions target by 2030 for its gas distribution system.

Consumers Energy Co.

Chart 1

CE's five-year investment plan (2025-2029)



Source: Company fillings.

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A portion of CE's service territory has a relatively high wildfire risk classification from the Federal Emergency Management Agency (FEMA). This area is contiguous and has a population of 10,000-15,000 people, 7,000-9,000 housing units (about 40%-60% occupied), and median home values of $100,000-$150,000, according to 2024 U.S. census data. Part of the company's capital spending plan is focused on smart electric systems and anticipates pursuing further undergrounding pilots, with the potential to underground up to 400 miles of electric lines per year, starting in 2027, to address some of its climate-related risks.

While CE has not been found culpable for any wildfires in its service territory and is not currently party to any material litigation, we will continue to monitor the company's ability to effectively manage its risks associated with adverse weather events.

We expect CE's credit measures to remain within the significant financial risk profile category. Throughout our base-case scenario, we expect funds from operations (FFO) to debt of 17%-20%.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of 17%-20%.

Downside scenario

We could lower our rating on CE if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or
- We lower our rating on parent CMS Energy.

Upside scenario

Although less likely, we could raise our rating on CE if:

- We raise our rating on CMS Energy; and
- CE's stand-alone financial measures improve, reflecting FFO to debt consistently above 20%.

Our Base-Case Scenario

Assumptions

- Consistent rate case filings and use of existing regulatory mechanisms;
- Elevated capital spending over the forecast period averaging $4 billion annually;
- Annual dividends averaging $1 billion-$1.2 billion annually;
- Equity infusion by the parent to maintain the company's capital structure;
- All debt maturities refinanced; and
- Continued negative discretionary cash flow financed in a balanced manner to support the regulated capital structure.

Key metrics

Period ending	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. $)	2022a	2023a	2024a	2025e	2026f	2027f
Adjusted ratios						
Debt/EBITDA (x)	4.6	4.6	4.6	4-5	4-5	4-5
FFO/debt (%)	18.7	17.6	17.9	17-19	18-20	18-20
FFO cash interest coverage (x)	7.0	5.4	5.5	5-6	5-6	5-6

a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas customers in Michigan. CE's electric business operates as a vertically integrated utility that generates, distributes, and sells electricity. The electric utility sources 25%-30% of its generation from purchased power, rather than from its own plants. The company also sells, stores, and transports natural gas. It is based in Jackson, Mich. CE contributes to about 95% of CMS' EBITDA.

Consumers Energy Co.

Peer Comparison

Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Wisconsin Power & Light Co.	Wisconsin Electric Power Co.	Consolidated Edison Co. of New York Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2024-12-31	2024-12-31	2024-12-31	2024-12-31	2024-12-31
Mil.	$	$	$	$	$
Revenue	7,076	6,166	1,845	3,980	14,129
EBITDA	2,692	3,078	870	1,859	4,748
Funds from operations (FFO)	2,218	2,840	712	1,219	3,564
Interest	551	696	176	275	1,207
Cash interest paid	493	469	172	576	1,121
Operating cash flow (OCF)	2,365	2,725	752	1,369	3,304
Capital expenditure	2,854	3,604	819	1,546	4,398
Free operating cash flow (FOCF)	(489)	(879)	(67)	(177)	(1,094)
Discretionary cash flow (DCF)	(1,605)	(1,655)	(263)	(417)	(2,167)
Cash and short-term investments	44	11	51	0	1,254
Gross available cash	44	11	51	0	1,254
Debt	12,403	13,266	4,025	6,163	25,253
Equity	11,413	11,154	4,101	5,492	19,971
EBITDA margin (%)	38.0	49.9	47.2	46.7	33.6
Return on capital (%)	6.9	7.3	6.8	11.7	6.2
EBITDA interest coverage (x)	4.9	4.4	4.9	6.8	3.9
FFO cash interest coverage (x)	5.5	7.1	5.1	3.1	4.2
Debt/EBITDA (x)	4.6	4.3	4.6	3.3	5.3
FFO/debt (%)	17.9	21.4	17.7	19.8	14.1
OCF/debt (%)	19.1	20.5	18.7	22.2	13.1
FOCF/debt (%)	(3.9)	(6.6)	(1.7)	(2.9)	(4.3)
DCF/debt (%)	(12.9)	(12.5)	(6.5)	(6.8)	(8.6)

Business Risk

Our assessment of CE's business risk profile reflects the company's monopolistic electric and natural gas utility operations and effective management of regulatory risk. The MPSC regulates

CE, and we view the regulatory environment in Michigan as above average compared with peers. This is demonstrated through the company's use of forward-looking test years and a streamlined 10-month rate case process. Furthermore, CE benefits from other constructive rate mechanisms, such as the power supply cost recovery adjustment rider, and the gas cost recovery adjustment rider.

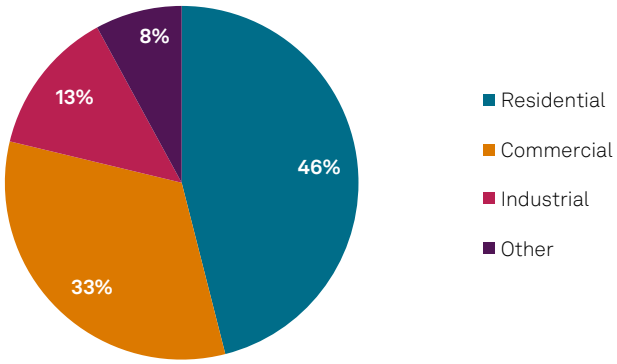
In 2023, the state passed a law that allows electric utilities in the state to earn a return equal to their pre-tax weighted average cost of capital on payments made under new purchased-power agreements. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag.

The company actively manages its gas supply to reduce price volatility and support its gas system operations by injecting natural gas into storage during the summer months for use during the winter months. During 2024, 47% of the natural gas supplied to all customers during the winter months came from storage. Additionally, CE's large customer base of about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan bolsters the company's business risk profile.

That said, the company’s service territory is susceptible to localized storms and adverse weather conditions. It is also exposed to cyclical commercial and industrial customers for its electric operations, which contribute about 45%-50% of the company’s electric revenues. Furthermore a 2024 third-party audit indicated below-average system reliability assessment for CE as measured by system and customer average interruption indices, which we will continue to monitor.

Chart 2

CE's 2024 electrical revenue by customer class



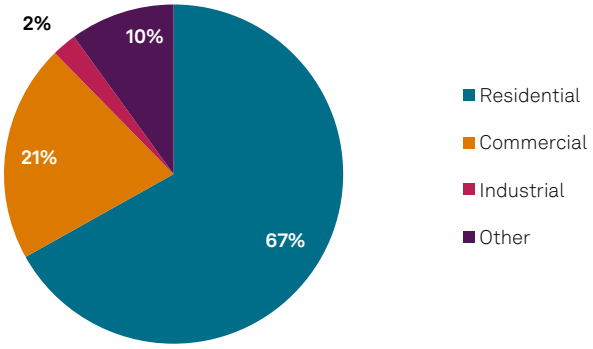
Source: Company fillings.

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Consumers Energy Co.

Chart 3

CE's 2024 gas revenue by customer class



Source: Company fillings.

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Financial Risk

We assess CE's financial measures using our medial volatility table, reflecting the company's lower risk regulated electric and gas utility operations and its effective management of regulatory risk. Under our base-case scenario, we expect:

- Elevated capital spending averaging about $4.0 billion annually over the forecast period;
- Dividends averaging $1.0 billion-$1.2 billion annually;
- Equity infusion by the parent to maintain the company's capital structure;
- Continued use of existing regulatory mechanisms;
- Negative discretionary cash flow; and
- The refinancing of all debt maturities.

As such, we anticipate financial measures to be consistent with the middle of the range for the significant financial risk category. Specifically, we forecast FFO to debt of 17%-20%.

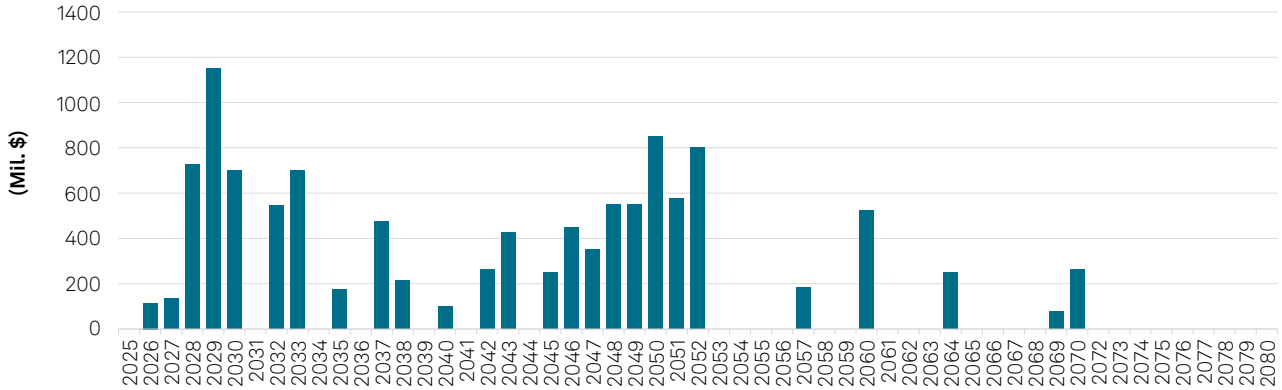
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Debt maturities

Chart 4

CE's debt maturities

First mortgage bonds as of December 2024



Source: Company fillings.

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Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024
Reporting period	2019a	2020a	2021a	2022a	2023a	2024a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,341	6,155	6,987	8,117	7,129	7,076
EBITDA	2,252	2,392	2,406	2,397	2,485	2,692
Funds from operations (FFO)	1,823	1,968	2,040	2,057	2,000	2,218
Interest expense	335	393	381	375	496	551
Cash interest paid	296	373	376	343	454	493
Operating cash flow (OCF)	1,688	1,265	2,013	984	2,415	2,365
Capital expenditure	2,191	2,254	2,136	2,275	2,279	2,854
Free operating cash flow (FOCF)	(502)	(989)	(124)	(1,291)	136	(489)
Discretionary cash flow (DCF)	(1,094)	(1,628)	(847)	(2,061)	(560)	(1,605)
Cash and short-term investments	11	20	22	43	35	44
Gross available cash	11	20	22	43	35	44
Debt	8,238	9,113	9,415	11,024	11,371	12,403

Consumers Energy Co.

Consumers Energy Co.--Financial Summary

Common equity	7,737	8,556	9,261	10,137	10,782	11,413
Adjusted ratios						
EBITDA margin (%)	35.5	38.9	34.4	29.5	34.9	38.0
Return on capital (%)	7.7	7.5	6.9	6.3	6.2	6.9
EBITDA interest coverage (x)	6.7	6.1	6.3	6.4	5.0	4.9
FFO cash interest coverage (x)	7.2	6.3	6.4	7.0	5.4	5.5
Debt/EBITDA (x)	3.7	3.8	3.9	4.6	4.6	4.6
FFO/debt (%)	22.1	21.6	21.7	18.7	17.6	17.9
OCF/debt (%)	20.5	13.9	21.4	8.9	21.2	19.1
FOCF/debt (%)	(6.1)	(10.9)	(1.3)	(11.7)	1.2	(3.9)
DCF/debt (%)	(13.3)	(17.9)	(9.0)	(18.7)	(4.9)	(12.9)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2024									
Company reported amounts	12,162	11,431	7,200	2,706	1,515	518	2,692	2,446	797	2,842
Cash taxes paid	-	-	-	-	-	-	19	-	-	-
Cash interest paid	-	-	-	-	-	-	(493)	-	-	-
Lease liabilities	69	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	5	1	1	(1)	4	-	-
Intermediate hybrids (equity)	19	(19)	-	-	-	1	(1)	(1)	(1)	-
Accessible cash and liquid investments	(44)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	13	(13)	(13)	-	(13)
Share-based compensation expense	-	-	-	25	-	-	-	-	-	-

Consumers Energy Co.

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Securitized stranded costs	(700)	-	(124)	(124)	(37)	(37)	37	(87)	-	-
Power purchase agreements	415	-	-	47	22	22	(22)	25	-	25
Asset-retirement obligations	548	-	-	33	33	33	-	-	-	-
Nonoperating income (expense)	-	-	-	-	55	-	-	-	-	-
Reclassification of interest and dividend cash flows	-	-	-	-	-	-	-	(9)	-	-
Debt: other	(65)	-	-	-	-	-	-	-	-	-
Total adjustments	241	(19)	(124)	(14)	74	33	(474)	(81)	(1)	12
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	12,403	11,413	7,076	2,692	1,589	551	2,218	2,365	796	2,854

Liquidity

We assess CE's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecast consolidated EBITDA declines 10%. We believe the supportive regulatory framework provides manageable cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity.

In addition, CE can absorb high-impact, low-probability events, in our view, as the company maintains about $1.1 billion in committed credit facilities through 2027, and can likely lower its capital spending (averaging $2.8 billion-$3.0 billion annually) during stressful periods, indicating a limited need for refinancing under such conditions. CE can borrow $500 million from parent CMS Energy as per its renewed credit agreement in December 2024.

Furthermore, our assessment reflects the company's prudent risk management and sound relationships with its banking group. Overall, we believe that the company can withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. As on June 30, 2025, CE had about $570 million of debt maturities in the next 12 months, and we

expect the company to proactively address these maturities well in advance of their scheduled due dates.

Principal liquidity sources

- Estimated cash FFO of about $2.8 billion;
- Credit facilities of about $1.1 billion; and
- Available cash of about $600 million as on June 30, 2025.

Principal liquidity uses

- Debt maturities of about $570 million over the next 12 months as on June 30, 2025;
- Working capital outflows of about $170 million; and
- Estimated maintenance capital spending of about $3.1 billion; and
- Dividends of about $1 billion.

Covenant Analysis

Requirements

CE's credit agreements contain a covenant for CE to maintain debt to capitalization below 65%.

Compliance expectations

In our base-case scenario, we expect CE to remain compliant with this covenant and have sufficient headroom.

Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of CE. The company's use of fossil fuel generation sources exposes it to heightened energy transition risks. The capacity of its generation portfolio comprises about 35% natural gas, 19% coal, 17% hydroelectric, 17% oil and gas, and 12% wind and solar as of Dec. 31, 2024. The company's accelerated coal retirement plan for its utility partially mitigates this risk. It includes a goal to be coal-free in owned generation in 2025 and have 60% of its utility's capacity portfolio sourced from clean energy resources by 2030 and 100% by 2040.

Furthermore, the company experienced heightened winter and convective storm activity in recent years.

While CE has not been found culpable for any wildfires in its service territory and is not currently party to litigation concerning these matters, a portion of its service territory has a relatively high wildfire risk classification from FEMA. This area is contiguous and has a population of about 10,000-15,000 inhabitants, 7,000-9,000 housing units, of which about 40%-60% are occupied, and median home values of $100,000-$150,000 according to 2024 U.S. Census data. Part of the company's capital spending plan is focused on smart electric systems and anticipates pursuing further undergrounding pilots, with the potential to underground up to 400 miles of electric lines per year starting in 2027. We will continue to monitor the company's ability to effectively manage its risks associated with adverse weather events.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy largely because we view the utility as integral to the group's identity, highly unlikely to be sold and having a strong commitment from management, given the company's emphasis on maintaining the size of the regulated utility operations relative to the nonutility businesses.

Given CE's stand-alone credit profile, and because CE is operationally separate and maintains sufficient insulating measures, we rate the utility one notch above the GCP. Some of the key insulating measures are:

- CE is a separate and stand-alone legal entity that functions independently (both financially and operationally), files its own rate cases, and is independently regulated by MPSC;
- CE has its own records and books, including stand-alone audited financial statements;
- The utility has its own funding arrangements, including issuing its own long-term debt, and it has a separate committed credit facility to cover its short-term funding needs;
- CE does not comingle funds, assets, or cash flow with parent CMS Energy or its other subsidiaries, and it does not participate in a money pool;
- We believe there is a strong economic basis for CMS Energy to preserve CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE is also a significant portion of CMS Energy, accounting for about 95% of the consolidated company; and
- There are no cross-default provisions between parent CMS Energy and CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

- As on Dec. 31, 2024, CE's capital structure comprised about $12.2 billion of long-term debt, including about $11.4 billion in first-mortgage bonds (FMBs), $700 million of securitized debt (all of which is deconsolidated from our credit metrics), and about $110 million of tax-exempt revenue bonds.

Analytical conclusions

- We rate the company's senior unsecured debt 'A-', in-line with the long-term issuer credit rating on CE as the rated issuances are senior unsecured debt issued by a qualifying investment grade utility as per our criteria.
- We base our 'A-2' short-term rating on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- We assign recovery ratings to FMBs issued by U.S. utilities, which can result in issue ratings being notched above an issuer credit rating on a utility, depending on the rating category and

the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of secured utility bonds that qualify for a recovery rating as defined in our criteria.

- CE's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Rating Component Scores	
Foreign currency issuer credit rating	**A-/Stable/A-2**
Local currency issuer credit rating	**A-/Stable/A-2**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Excellent
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**a-**
Modifiers	
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a-**
Group credit profile	**BBB+**
Entity status within group	**Core, Insulated (no change to SACP)**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, July 7, 2025
- General Criteria: Hybrid Capital: Methodology And Assumptions, Feb. 10, 2025
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017

Consumers Energy Co.

- Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of September 15, 2025)*

Consumers Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Issuer Credit Ratings History	
30-Oct-2019	A-/Stable/A-2
03-Dec-2014	BBB+/Stable/A-2
11-Sep-2014	BBB/Positive/A-2
Related Entities	
CMS Energy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Junior Subordinated	BBB-
Preferred Stock	BBB-
Senior Unsecured	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

Consumers Energy Co.

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FitchRatings

Corporates
Electric-Corporate
United States

Consumers Energy Company

Consumers Energy Company (Consumers Energy; A–/Stable) ratings derive support from its regulated utility operations under continued regulatory support in Michigan. Sizeable capital expenditure (capex) plans focused on reliability, decarbonization and evolving load demand in the state are expected to pressure Consumers Energy's funds from operations (FFO) leverage to its 4.5x rating threshold in the near term before improving to 4.4x in 2028 and 4.2x in 2029.

Key Rating Drivers

Decarbonization and Reliability Drive Capex: Consumers Energy's capex plan increased to $20 billion for 2025-2029, from $17 billion for 2024-2028. The increase is partly driven by the 9 GW solar and 4 GW wind pipeline filed as part of Consumer Energy's November 2024 Renewable Energy Plan, aligning with Michigan's target of 60% renewable energy by 2035. The increase also pertains to reliability spend on the electric distribution side. Consumers Energy is also on track to eliminate coal from its generation mix by mid-2025.

Fitch anticipates further capex for system resource adequacy and potential load growth in the state as Consumers Energy plans an Integrated Resource Plan in 2H26. Michigan's recent energy legislation include expanded incentives and improved economics for PPAs, which provide some investment flexibility in Fitch's view. Fitch believes concerns on the capex are largely mitigated by the Michigan Public Service Commission's (MPSC) constructive ratemaking policies and alignment with state policy, which is key to maintaining credit metrics. Monetization of tax credits on renewable projects and parent equity should provide further support.

Near-Term Leverage Pressured: Fitch expects Consumers Energy's FFO leverage to be weaker than previously forecasted in the near term, with no headroom, but then improve to 4.4x in 2028 and 4.2x in 2029. This is due to higher capex, though partially offset by rate base growth and load growth. Subsequent leverage improvement is expected from increasing tax credit monetizations on completed projects and continued regulatory support.

Fitch estimates Consumers Energy will sell about $600 million of tax credits over the forecast period. Fitch assumes any changes in the ability to monetize tax credits will result in adjustments to Consumers Energy's financial plan, supporting current credit metrics.

Retails Sales Growth Expected: Fitch expects Consumers Energy to benefit from increasing energy demand from manufacturing activity and data center demand in Michigan. Fitch now estimates previously flat retail sales to grow by 1% to 3% annually through 2029. A further uptick is likely in the outer years given the evolving data center activity in the state, especially after the recent sales and use tax exemption on data center equipment. While load growth is cash flow accretive, the continued ability to recover capital investments in a credit-supportive manner will remain key to the ratings.

Rate Case Activity: In December 2024, Consumers Energy filed a gas rate case requesting a $248 million increase, with a 10.25% return on equity (ROE) and a test year ending in October 2026. A decision is expected in 4Q25. An electric rate case requesting a $277 million increase, based on a 10.25% ROE and a test year ending February 2026, was also filed in May 2024. The MPSC recently delivered a largely constructive decision authorizing a $154 million revenue increase, with a 9.9% allowed ROE, and recovery of $22 million through a separate surcharge for distribution deferral.

Ratings

Long-Term IDR	A–
Short-Term IDR	F2
Senior Unsecured Debt - Long-Term Rating	A
Senior Secured Debt - Long-Term Rating	A+
Senior Unsecured Debt - Short-Term Rating	F2
Outlook	
Long-Term Foreign-Currency IDR	Stable

Click here for the full list of ratings

ESG and Climate

Highest ESG Relevance Scores	
Environmental	3
Social	3
Governance	3
2035 Climate Vulnerability Signal:	39

Applicable Criteria

Sector Navigators – Addendum to the Corporate Rating Criteria (December 2024)

Corporates Recovery Ratings and Instrument Ratings Criteria (August 2024)

Corporate Hybrids Treatment and Notching Criteria (November 2020)

Parent and Subsidiary Linkage Rating Criteria (June 2023)

Corporate Rating Criteria (December 2024)

Related Research

Global Corporates Macro and Sector Forecasts — March 2025 (March 2025)

North American Utilities Outlook 2025 (December 2024)

North American Utilities, Power & Gas Dashboard: 4Q24 (January 2025)

North American Utilities Monitor: 2Q24 (August 2024)

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Michigan Regulation Remains Supportive: Fitch notes that the regulatory environment under the MPSC has been characterized by some recent lighter-than-expected rate outcomes and increased scrutiny on storm responses. Nevertheless, Fitch believes the framework remains constructive from a credit perspective, allowing for full pass-through of fuel costs and purchased power, forward-looking test years and a timely 10-month rate case resolution. Furthermore, Consumers Energy's authorized ROE of 9.9% compares favorably with industry averages. Fitch expects continued annual rate case filings.

Storm Audit Concluded: An MPSC-ordered audit of utility compliance with storm outages and safety regulations was concluded in late 2024. The audit findings cited the need to address aging infrastructure, improve maintenance practices and manage outages more effectively to enhance service reliability. While Fitch does not expect an immediate material negative outcome, the audit could highlight higher reliability investment needs and higher regulatory scrutiny in subsequent rate cases. Fitch continues to believe that the risk of performance-based penalties is manageable within Consumers Energy's current credit profile.

Parent/Subsidiary Linkage: There is parent-subsidiary rating linkage between CMS Energy Corporation (CMS Energy; BBB/Stable) and Consumers Energy. Fitch considers CMS Energy's standalone credit profile (SCP), based upon consolidated metrics, to be weaker than Consumer Energy's SCP. Emphasis is placed on the latter's status as a regulated entity. Legal ring-fencing is considered porous, given the general protections afforded by economic regulation. Access and control are also evaluated as porous. CMS Energy centrally manages the treasury function; however, both entities issue their own long-term debt. Fitch will limit the difference between the Long-Term IDRs of CMS Energy and Consumers Energy to two notches.

Financial Summary

(USD Mil.)	2021	2022	2023	2024
Gross revenue	6,987	8,116	7,127	7,050
EBITDA	2,195	2,260	2,345	2,538
CFO (Fitch-defined)	1,948	954	2,387	2,328
FFO	1,974	2,052	2,144	2,223
Debt	8,727	10,230	10,613	11,589
FFO leverage (x)	3.9	4.4	4.2	4.4
FFO interest coverage (x)	8.0	8.1	6.2	5.9
EBITDA leverage (x)	4.0	4.5	4.5	4.6

F – Forecast
Source: Fitch Ratings, Fitch Solutions

Peer Analysis

The credit profile of Consumers Energy is comparable to peers like DTE Electric Company (DTEE; A-/Stable), Northern States Power Company-Minnesota (NSP-Minnesota; A-/Stable) and Northern States Power Company-Wisconsin (NSP-Wisconsin; A-/Stable), and Public Service Company of Colorado (A-/Stable). All four are regulated utilities with single state operations albeit in generally constructive environments.

Fitch forecasts Consumer Energy's FFO leverage to average at its 4.5x threshold in the near term and then improve to 4.2x through 2029. This is better than the 4.5x to 4.8x projected in 2025-2027 for the pure gas utility, DTE Gas Company (BBB+/Stable). Financial metrics at other electric peers are marginally stronger, with leverage forecasted to average 3.8x through 2027 at DTEE, 3.8x-4.2x for NSP-Wisconsin and 3.6x for NSP-Minnesota, making them well-positioned for their ratings.

Rating Sensitivities

Factors that Could, Individually or Collectively, Lead to Negative Rating Action/Downgrade

- FFO leverage expected to exceed 4.5x on a sustained basis;
- A material deterioration of the Michigan regulatory environment;
- A downgrade to CMS Energy's Long-Term IDR.

Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade

- A positive rating action on Consumers Energy would also require an equally positive rating action on its parent, CMS Energy, under Fitch's Parent and Subsidiary Linkage Criteria;
- FFO leverage expected to be less than 3.5x on a sustained basis.

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Liquidity and Debt Structure

Fitch considers liquidity for Consumers Energy to be adequate.

Consumers Energy's $500 million CP program is supported by its $1.1 billion revolving credit facility (RCF) maturing in December 2027, with $1 billion available as of Dec. 31, 2024. It also has a separate $250 million RCF with $192 million available.

Consumers Energy had $44 million in unrestricted cash as of Dec. 31, 2024. Consumers Energy has bond maturities of $115 million in 2026, $135 million in 2027 and $725 million in 2028. Fitch views these maturities as manageable given the history of successful refinancing and expected continued access to capital markets. As of Dec. 31, 2024, Consumers Energy was compliant with its consolidated debt to capitalization covenants of 65%.

ESG Considerations

The highest level of ESG credit relevance is a score of '3', unless otherwise disclosed in this section. A score of '3' means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. Fitch's ESG Relevance Scores are not inputs in the rating process; they are an observation on the relevance and materiality of ESG factors in the rating decision. For more information on Fitch's ESG Relevance Scores, visit https://www.fitchratings.com/topics/esg/products#esg-relevance-scores.

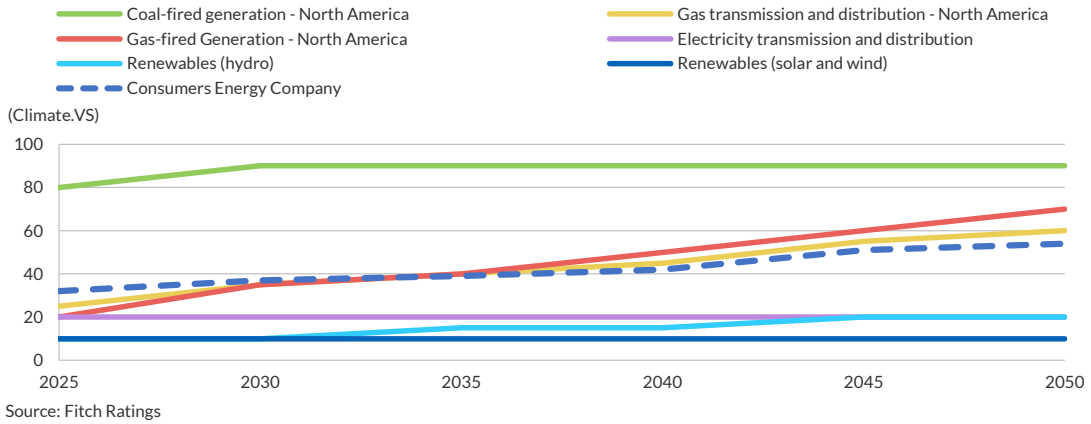
Climate Vulnerability Considerations

Fitch uses Climate Vulnerability Signals (Climate.VS) as a screening tool to identify sectors and Fitch-rated issuers that are potentially most exposed to credit-relevant climate transition risks and, therefore, require additional consideration of these risks in rating reviews. Climate.VS range from 0 (lowest risk) to 100 (highest risk). For more information on Climate.VS, see Fitch's Corporate Rating Criteria. For more detailed, sector-specific information on how Fitch perceives climate-related transition risks, see Climate Vulnerability Signals for Non-Financial Corporate Sectors.

The 2024 asset-weighted Climate.VS for Consumers Energy is 39 for 2035 out of 100. The Climate.VS is a function of ownership of around 1.3 GW of coal-fired generating capacity and 2.5 GW of gas-fired capacity. The score also reflects growing opposition to methane and other greenhouse gas (GHG) emissions in recent years, driven by growing concern about the impact of global climate change and evolving state and federal policies to reduce GHG emissions.

Consumers Energy remains on track to phase out coal generation by 2025. Consumers Energy projects to be net zero in terms of CO2 emissions by 2040 in its electric system and net zero menthane by 2030 in its natural gas distribution system and net zero GHG by 2050 in its overall system. By 2035, Consumers Energy expects to move towards a portfolio supported by around 60% renewable energy generation as it adds solar, wind and storage resources.

Climate.VS Evolution
As of Dec 31, 2024



Source: Fitch Ratings

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Liquidity and Debt Maturities

Cash and Maturities Report

(USD Mil.)	December 31, 2023	December 31, 2024
Total cash and cash equivalents	56	119
Short-term investments	—	—
Less not readily available cash and cash equivalents	21	75
Fitch-defined readily available cash and cash equivalents	**35**	**44**
Availability under committed lines of credit	1,182	1,199
Total liquidity	1,217	1,243
LTM EBITDA after associates and minorities	2,345	2,538
LTM FCF	-1,368	-1,309

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Scheduled Debt Maturities

(USD Mil.)	December 31, 2024
2025	-
2026	115
2027	135
2028	725
2029	-
Thereafter	10,614
Total	**11,589**

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Key Assumptions

- Constructive regulatory environment in Michigan with continuance of authorized ROEs for both electric and gas utility operations;
- Gas rate case decision in 4Q25;
- Annual rate case filings;
- Largely flat annual natural gas sales growth;
- Electric sales growth ranging from 1% to 3% over 2025-2029;
- Total utility capex in line with management's assumptions;
- Dividend growth of 5% per year;
- Normal weather;
- Annual equity issuances of around $500 million near term, and lower subsequently;
- Tax credit transfers of $600 million over 2025-2029.

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Financial Data

(USD Mil.)	2021	2022	2023	2024
Summary income statement				
Gross revenue	6,987	8,116	7,127	7,050
Revenue growth (%)	13.5	16.2	-12.2	-1.1
EBITDA before income from associates	2,195	2,260	2,345	2,538
EBITDA margin (%)	31.4	27.9	32.9	36.0
EBITDA after associates and minorities	2,195	2,260	2,345	2,538
EBIT	1,152	1,212	1,249	1,463
EBIT margin (%)	16.5	14.9	17.5	20.8
Gross interest expense	-291	-316	-416	-467
Pretax income including associate income/loss	1,024	1,085	1,028	1,209
Summary balance sheet				
Readily available cash and equivalents	22	43	35	44
Debt	8,727	10,230	10,613	11,589
Net debt	8,705	10,187	10,578	11,545
Summary cash flow statement				
EBITDA	2,195	2,260	2,345	2,538
Cash interest paid	-277	-290	-401	-445
Cash tax	10	2	-31	19
Dividends received less dividends paid to minorities (inflow/outflow)	—	—	—	—
Other items before FFO	40	73	203	66
FFO	1,974	2,052	2,144	2,223
FFO margin (%)	28.3	25.3	30.1	31.5
Change in working capital	-26	-1,098	243	105
CFO (Fitch-defined)	1,948	954	2,387	2,328
Total non-operating/nonrecurring cash flow	—	—	—	—
Capex	-2,052	-2,239	-3,060	-2,842
Capital intensity (capex/revenue) (%)	29.4	27.6	42.9	40.3
Common dividends	-724	-771	-695	-795
FCF	-828	-2,056	-1,368	-1,309
FCF margin (%)	-11.9	-25.3	-19.2	-18.6
Net acquisitions and divestitures	—	—	—	124
Other investing and financing cash flow items	-131	-87	-121	-367
Net debt proceeds	393	1,474	1,010	880
Net equity proceeds	575	685	475	735
Total change in cash	9	16	-4	63
Calculations for forecast publication				
Capex, dividends, acquisitions and other items before FCF	-2,776	-3,010	-3,755	-3,513
FCF after acquisitions and divestitures	-828	-2,056	-1,368	-1,185
FCF margin after net acquisitions (%)	-11.9	-25.3	-19.2	-16.8
Gross Leverage ratios (x)				
EBITDA leverage	4.0	4.5	4.5	4.6
FFO leverage	3.9	4.4	4.2	4.4
(CFO-capex)/debt	-1.2	-12.6	-6.3	-4.4
Net Leverage ratios (x)				
EBITDA net leverage	4.0	4.5	4.5	4.6
FFO net leverage	3.9	4.4	4.2	4.4
(CFO-capex)/net debt	-1.2	-12.6	-6.4	-4.5
Coverage ratios (x)				
EBITDA interest coverage	7.9	7.8	5.8	5.7

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FFO interest coverage	8.0	8.1	6.2	5.9
FFO fixed-charge coverage	8.0	8.1	6.2	5.9

CFO – Cash flow from operations
Source: Fitch Ratings, Fitch Solutions

How to Interpret the Forecast Presented

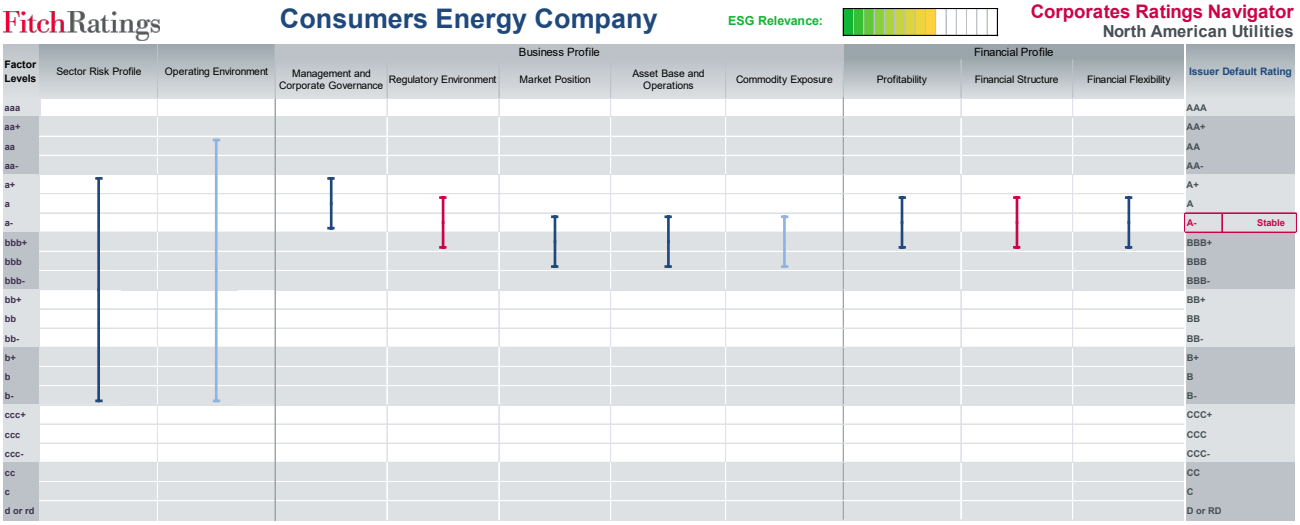
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Ratings Navigator



Bar Chart Legend:	
Vertical Bars = Range of Rating Factor	Bar Arrows = Rating Factor Outlook
Bar Colors = Relative Importance	⇧ Positive
Higher Importance	⇩ Negative
Average Importance	⇳ Evolving
Lower Importance	▭ Stable

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Consumers Energy Company

Corporates Ratings Navigator
North American Utilities

Operating Environment

aa+		Economic Environment	aa	Very strong combination of countries where economic value is created and where assets are located.
aa		Financial Access	aa	Very strong combination of issuer specific funding characteristics and of the strength of the relevant local financial market.
		Systemic Governance	aa	Systemic governance (eg rule of law, corruption; government effectiveness) of the issuer's country of incorporation consistent with 'aa'.
b-				
ccc+				

Management and Corporate Governance

aa-		Management Strategy	a	Coherent strategy and good track record in implementation.
a+		Governance Structure	aa	No record of governance failing. Experienced board exercising effective check and balance to management. No ownership concentration.
a		Group Structure	a	Group structure shows some complexity but mitigated by transparent reporting.
a-		Financial Transparency	a	High quality and timely financial reporting.
bbb+				

Regulatory Environment

a+		Degree of Transparency and Predictability	a	Track record of transparent and predictable regulation.
a		Timeliness of Cost Recovery	a	Minimal lag to recover capital and operating costs.
a-		Trend in Authorized ROEs	a	Above-average authorized ROE.
bbb+		Mechanisms Available to Stabilize Cash Flows	bbb	Revenues partially insulated from variability in consumption.
bbb		Mechanisms Supportive of Creditworthiness	bbb	Effective regulatory ring-fencing or minimum creditworthiness requirements.

Market Position

a		Market Structure	a	Well-established market structure with complete transparency in price-setting mechanisms.
a-		Consumption Growth Trend	bbb	Customer and usage growth in line with industry averages.
bbb+		Customer Mix	a	Favorable customer mix.
bbb		Geographic Location	bbb	Beneficial location or reasonable locational diversity.
bbb-		Supply Demand Dynamics	bbb	Moderately favorable outlook for prices/rates.

Asset Base and Operations

a		Diversity of Assets	bbb	Good quality and/or reasonable scale diversified assets.
a-		Operations Reliability and Cost Competitiveness	a	Track record of reliable, low-cost operations.
bbb+		Exposure to Environmental Regulations	bbb	Limited or manageable exposure to environmental regulations.
bbb		Capital and Technological Intensity of Capex	bbb	Moderate reinvestments requirements in established technologies.
bbb-				

Commodity Exposure

a		Ability to Pass Through Changes in Fuel	bbb	Limited exposure to changes in commodity costs.
a-		Underlying Supply Mix	bbb	Low variable costs and moderate flexibility of supply.
bbb+		Hedging Strategy	a	Highly captive supply and customer base.
bbb				
bbb-				

Profitability

a+		Free Cash Flow	bbb	Structurally neutral to negative FCF across the investment cycle.
a		Volatility of Profitability	a	Higher stability and predictability of profits relative to utility peers.
a-				
bbb+				
bbb				

Financial Structure

a+		EBITDA Leverage	a	3.25x
a		FFO Leverage	a	3.5x
a-				
bbb+				
bbb				

Financial Flexibility

a+		Financial Discipline	a	Clear commitment to maintain a conservative policy with only modest deviations allowed.
a		Liquidity	bbb	One-year liquidity ratio above 1.25x. Well-spread maturity schedule of debt but funding may be less diversified.
a-		FFO Interest Coverage	bbb	4.5x
bbb+				
bbb				

How to Read This Page: The left column shows the three-notch band assessment for the overall Factor, illustrated by a bar. The right column breaks down the Factor into Sub-Factors, with a description appropriate for each Sub-Factor and its corresponding category.

Credit-Relevant ESG Derivation

Overall ESG

Consumers Energy Company has 12 ESG potential rating drivers	key driver	0	issues	5
Emissions from operations	driver	0	issues	4
Fuel use to generate energy and serve load	potential driver	12	issues	3
Impact of waste from operations	not a rating driver	2	issues	2
Plants' and networks' exposure to extreme weather		0	issues	1
Product affordability and access				
Quality and safety of products and services; data security				

Showing top 6 issues

For further details on Credit-Relevant ESG scoring, see page 3.

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North American Utilities

Credit-Relevant ESG Derivation

Consumers Energy Company has 12 ESG potential rating drivers

- Consumers Energy Company has exposure to emissions regulatory risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to energy productivity risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to waste & impact management risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to extreme weather events but this has very low impact on the rating.
- Consumers Energy Company has exposure to access/affordability risk but this has very low impact on the rating.
- Consumers Energy Company has exposure to customer accountability risk but this has very low impact on the rating.

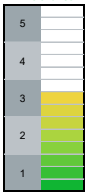
Showing top 6 issues

				ESG Relevance to Credit Rating
key driver	0	issues	5	
driver	0	issues	4	
potential driver	12	issues	3	
not a rating driver	2	issues	2	
	0	issues	1	

Environmental (E) Relevance Scores

General Issues	E Score	Sector-Specific Issues	Reference
GHG Emissions & Air Quality	3	Emissions from operations	Asset Base and Operations; Commodity Exposure; Regulation; Profitability
Energy Management	3	Fuel use to generate energy and serve load	Asset Base and Operations; Commodity Exposure; Profitability
Water & Wastewater Management	2	Water used by hydro plants or by other generation plants, also effluent management	Asset Base and Operations; Regulation; Profitability
Waste & Hazardous Materials Management; Ecological Impacts	3	Impact of waste from operations	Asset Base and Operations; Regulation; Profitability
Exposure to Environmental Impacts	3	Plants' and networks' exposure to extreme weather	Asset Base and Operations; Regulation; Profitability

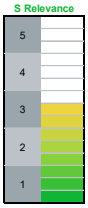
E Relevance



Social (S) Relevance Scores

General Issues	S Score	Sector-Specific Issues	Reference
Human Rights, Community Relations, Access & Affordability	3	Product affordability and access	Asset Base and Operations; Regulation; Profitability; Financial Structure
Customer Welfare - Fair Messaging, Privacy & Data Security	3	Quality and safety of products and services; data security	Regulation; Profitability
Labor Relations & Practices	3	Impact of labor negotiations and employee (dis)satisfaction	Asset Base and Operations; Profitability
Employee Wellbeing	2	Worker safety and accident prevention	Profitability; Asset Base and Operations
Exposure to Social Impacts	3	Social resistance to major projects that leads to delays and cost increases	Asset Base and Operations; Profitability

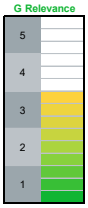
S Relevance



Governance (G) Relevance Scores

General Issues	G Score	Sector-Specific Issues	Reference
Management Strategy	3	Strategy development and implementation	Management and Corporate Governance
Governance Structure	3	Board independence and effectiveness; ownership concentration	Management and Corporate Governance
Group Structure	3	Complexity, transparency and related-party transactions	Management and Corporate Governance
Financial Transparency	3	Quality and timing of financial disclosure	Management and Corporate Governance

G Relevance



How to Read This Page
ESG relevance scores range from 1 to 5 based on a 15-level color gradation. Red (5) is most relevant to the credit rating and green (1) is least relevant.
The Environmental (E), Social (S) and Governance (G) tables break out the ESG general issues and the sector-specific issues that are most relevant to each industry group. Relevance scores are assigned to each sector-specific issue, signaling the credit-relevance of the sector-specific issues to the issuer's overall credit rating. The Criteria Reference column highlights the factor(s) within which the corresponding ESG issues are captured in Fitch's credit analysis. The vertical color bars are visualizations of the frequency of occurrence of the highest constituent relevance scores. They do not represent an aggregate of the relevance scores or aggregate ESG credit relevance.
The Credit-Relevant ESG Derivation table's far right column is a visualization of the frequency of occurrence of the highest ESG relevance scores across the combined E, S and G categories. The three columns to the left of ESG Relevance to Credit Rating summarize rating relevance and impact to credit from ESG issues. The box on the far left identifies any ESG Relevance Sub-factor issues that are drivers or potential drivers of the issuer's credit rating (corresponding with scores of 3, 4 or 5) and provides a brief explanation for the relevance score. All scores of '4' and '5' are assumed to reflect a negative impact unless indicated with a '+' sign for positive impact.
Classification of ESG issues has been developed from Fitch's sector ratings criteria. The General Issues and Sector-Specific Issues draw on the classification standards published by the United Nations Principles for Responsible Investing (PRI), the Sustainability Accounting Standards Board (SASB), and the World Bank.

CREDIT-RELEVANT ESG SCALE
How relevant are E, S and G issues to the overall credit rating?

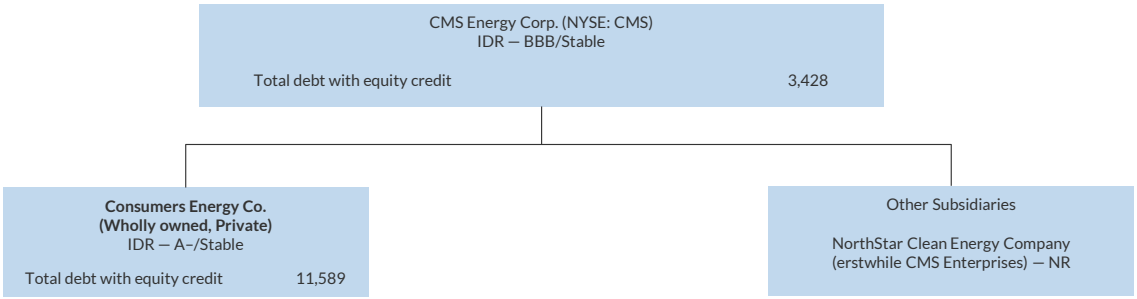
5	Highly relevant, a key rating driver that has a significant impact on the rating on an individual basis. Equivalent to "higher" relative importance within Navigator.
4	Relevant to rating, not a key rating driver but has an impact on the rating in combination with other factors. Equivalent to "moderate" relative importance within Navigator.
3	Minimally relevant to rating, either very low impact or actively managed in a way that results in no impact on the entity rating. Equivalent to "lower" relative importance within Navigator.
2	Irrelevant to the entity rating but relevant to the sector.
1	Irrelevant to the entity rating and irrelevant to the sector.

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Simplified Group Structure Diagram

CMS Energy is a holding company that owns Consumers Energy (a regulated electric and natural gas utility) and NorthStar Clean Energy Company (NorthStar; an independent power producer and marketer). Consumers Energy issues its own debt through the public debt market, and NorthStar obtains its own financing.

Organizational and Debt Structure — Consumers Energy Company
(USD Mil., as of December 31, 2024)



IDR – Issuer Default Rating. NR – Not rated.
Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

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Peer Financial Summary

Company	Issuer Default Rating	Financial statement date	Gross revenue (USD mil.)	FFO (USD mil.)	FFO leverage (x)	FFO interest coverage (x)	EBITDA leverage (x)
Consumers Energy Company	A-						
	A-	2024	7,050	2,223	4.4	5.9	4.6
	A-	2023	7,127	2,144	4.2	6.2	4.5
	A-	2022	8,116	2,052	4.4	8.1	4.5
DTE Electric Company	A-						
	A-	2024	6,277	2,537	3.9	6.1	4.2
	A-	2023	5,804	1,968	4.5	5.6	4.1
	A-	2022	6,397	2,463	3.6	7.8	4.0
DTE Gas Company	BBB+						
	BBB+	2024	1,783	507	4.7	5.5	4.4
	BBB+	2023	1,726	560	4.0	6.7	3.9
	BBB+	2022	1,894	695	3.3	9.0	4.1
Northern States Power Company-Minnesota	A-						
	A-	2023	6,043	1,985	3.3	7.3	3.9
	A-	2022	6,684	1,587	3.9	6.7	3.7
	A-	2021	5,756	1,519	3.9	6.9	3.7
Northern States Power Company-Wisconsin	A-						
	A-	2023	1,177	295	3.7	6.8	3.3
	A-	2022	1,201	270	3.7	7.4	3.2
	A-	2021	1,105	254	3.7	7.4	3.4
Public Service Company of Colorado	A-						
	A-	2023	5,519	1,650	4.1	6.4	4.2
	A-	2022	5,708	1,448	4.2	6.2	4.0
	A-	2021	4,815	1,354	4.2	6.3	4.1
Southwestern Public Service Company	BBB						
	BBB	2023	2,152	613	4.6	5.6	4.1
	BBB	2022	2,426	759	3.7	6.5	4.0
	BBB	2021	2,465	554	4.9	6.0	4.9

Source: Fitch Ratings, Fitch Solutions

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Fitch Adjusted Financials

(USD mil., as of December 31, 2024)	Notes and formulas	Standardized values	Fair value and other debt adjustments	Lease treatment	Other adjustments	Adjusted values
Income statement summary						
Revenue		7,200	—	—	-150	7,050
EBITDA	(a)	2,706	—	-18	-150	2,538
Depreciation and amortization		-1,191	—	5	111	-1,075
EBIT		1,515	—	-13	-39	1,463
Balance sheet summary						
Debt	(b)	12,177	112	—	-700	11,589
Of which other off-balance-sheet debt		—	—	—	—	—
Lease-equivalent debt		—	—	—	—	—
Lease-adjusted debt		12,177	112	—	-700	11,589
Readily available cash and equivalents	(c)	44	—	—	—	44
Not readily available cash and equivalents		75	—	—	—	75
Cash flow summary						
EBITDA	(a)	2,706	—	-18	-150	2,538
Dividends received from associates less dividends paid to minorities	(d)	—	—	—	—	—
Interest paid	(e)	-484	—	13	26	-445
Interest received	(f)	47	—	—	—	47
Preferred dividends paid	(g)	-2	—	—	—	-2
Cash tax paid		19	—	—	—	19
Other items before FFO		53	—	—	13	66
FFO	(h)	2,339	—	-5	-111	2,223
Change in working capital		105	—	—	—	105
CFO	(i)	2,444	—	-5	-111	2,328
Non-operating/nonrecurring cash flow		—	—	—	—	—
Capex	(j)	-2,842	—	—	—	-2,842
Common dividends paid		-795	—	—	—	-795
FCF		-1,193	—	-5	-111	-1,309
Gross leverage (x)						
EBITDA leverage	b/(a+d)	4.5	—	—	—	4.6
FFO leverage	b/(h-e-f-g)	4.4	—	—	—	4.4
(CFO-capex)/debt (%)	(i+j)/b	-3.2	—	—	—	-4.4
Net leverage (x)						
EBITDA net leverage	(b-c)/(a+d)	4.5	—	—	—	4.6
FFO net leverage	(b-c)/(h-e-f-g)	4.4	—	—	—	4.4
(CFO-capex)/net debt (%)	(i+j)/(b-c)	-3.3	—	—	—	-4.5
Coverage (x)						
EBITDA interest coverage	(a+d)/(-e)	5.6	—	—	—	5.7
FFO interest coverage	(h-e-f-g)/(-e-g)	5.7	—	—	—	5.9

CFO – Cash flow from operations
Notes: The standardized items presented above are based on Fitch's taxonomy for the given sector and region.
Reported items may not match the Fitch taxonomy, but they are captured into corresponding lines accordingly.
Debt includes other off-balance-sheet debt.
Debt in the standardized values column excludes lease liabilities of USD93 million.
Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

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Parent Subsidiary Linkage Analysis

Key Risk Factors and Notching Approach

Parent	CMS Energy Corporation
Parent LT IDR	BBB
Subsidiary	Consumers Energy Company
Subsidiary LT IDR	A–
Path	Stronger Subsidiary
Legal ring-fencing	Porous
Access and control	Porous
Notching matrix outcome	Consolidated+2
Override applied	No
Notching approach	Consolidated +2

LT IDR – Long-Term Issuer Default Rating
Source: Fitch Ratings

Stronger Subsidiary Notching Matrix

Access and control	Open	Porous	Insulated
With open ring-fencing	Consolidated	Consolidated+1	Consolidated+2[b]
With porous ring-fencing	Consolidated+1	Consolidated+2[b]	Consolidated+2[b]
With insulated ring-fencing	[a]	Standalone	Standalone

[a] It is unlikely that considerations for "insulated" legal ring-fencing would coexist with the conditions outlined under "open" for access and control. It is more likely that other factors relevant to legal ring-fencing or access and control, but not within this table, would move either one, or both, of the individual Linkage Factor Assessments (LFAs) to a "porous" level that would lead to a consolidated+1, consolidated+2 or standalone outcome.
[b] Notching is capped at the subsidiary's Standalone Credit Profile.
Source: Fitch Ratings

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For information on the participation status in the rating process of an issuer listed in this report, please refer to the most recent rating action commentary for the relevant issuer, available on the Fitch Ratings website.

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Industry Credit Outlook 2026

S&P Global Ratings

North America Regulated Utilities

Data center growth will support credit quality in 2026

January 14, 2026

This report does not constitute a rating action.



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What's changed?

Electricity sales growth. After nearly two decades of stagnant growth, sales growth has returned, powered by data center expansion.

Rising capital spending. Capital spending broke a new record in 2025 for the fourth consecutive year, reflecting about $250 billion.

Hybrid issuance. Hybrid security issuance also exceeded prior levels at about $30 billion.

What are the key assumptions for 2026?

Credit-supportive funding of cash flow deficits. The industry's cash flow deficits at about $100 billion requires balanced equity and debt funding to maintain credit quality.

Managing regulatory risk. The industry's rate case filing revenue requirements are materially increasing, requiring consistently fair rate case orders to maintain credit quality.

Managing the customer bill. The electric bill represents about 2% of household income, and significant bill increases could challenge a utility's ability to manage regulatory risk.

What are the key risks around the baseline?

Physical risks. Climate change is increasing the frequency of extreme and devastating hurricanes, storms, and wildfires, which is heightening credit risks for North America's investor-owned utilities (IOUs).

Common equity issuance. Common equity issuance at about $16 billion in 2025, or 40% higher than 2024, must be sustained given the industry's robust cash flow deficits.

Minimal financial cushion from downgrade threshold. About 40% of the industry is operating with limited ability to absorb unexpected events beyond their base case.

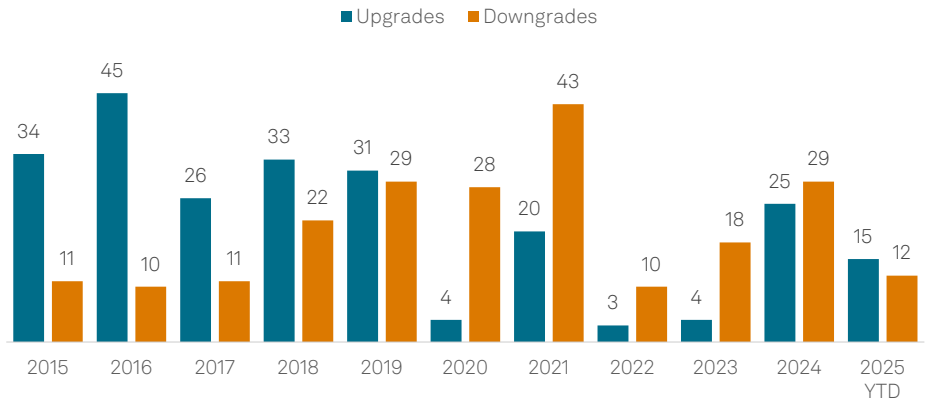
Industry Outlook

Ratings trends and outlook

After five years of downgrades consistently outpacing upgrades, 2025 upgrades have finally outpaced downgrades. Furthermore, the percentage of companies with a negative outlook has decreased to about 10% compared to the more recent historical average of about 20%. This all points to a potentially more stable environment for credit quality in 2026.

Chart 1

Upgrades and downgrades



Source: YTD—Year to date as of Nov. 30, 2025. Source: S&P Global Ratings.

Main assumptions about 2026 and beyond

1. Electricity sales growth

For nearly the past two decades electricity sales have been flat, reflecting conservation efforts that have offset new customer growth. However, with data center growth, we expect the industry's electricity sales will increase by 1%-2%. This transformation represents an opportunity but still brings considerable risks to credit quality.

2. Phase out of tax credits

Under the 2025 U.S. budget bill, solar or wind projects started by June 2026 should qualify for tax credits. As such, the industry should benefit from tax credit transferability through 2030, which we assess as supportive of credit quality. Furthermore, we believe the transition period allows for ample adjustment time.

3. Legislative enactments to reduce regulatory lag and wildfire risks

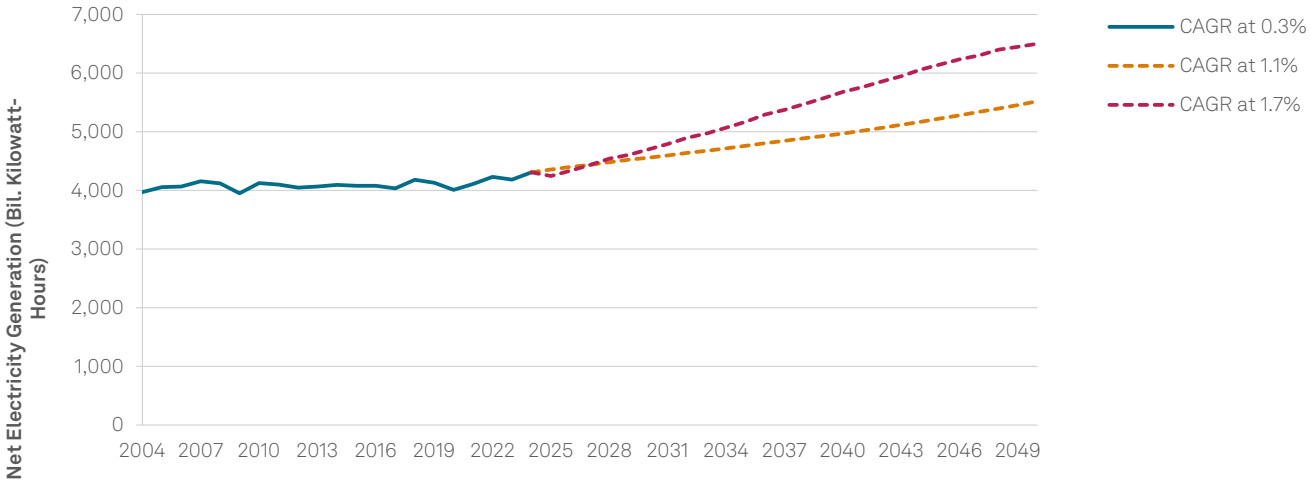
Given the increasing opportunities for the utility industry, no less than 14 states enacted legislation in 2025 that either reduces regulatory lag (the timing difference between when a utility incurs costs and when it's recovered from ratepayers) or reduces wildfire risks. We assess these developments as supportive of credit quality and expect this trend will persist, reducing the industry's risks and improving the industry's profitability.

A transformative industry shift. During the past two decades of stagnant electricity sales growth, the industry concentrated on managing regulatory risk and reducing regulatory lag, as there was no sales growth that could offset regulatory delays. This was a particularly challenging period for the industry, especially considering it also had to manage other concurrent risks, including declining interest rates, inflation, supply-chain issues, and commodity price spikes.

Given our expectations for rising electricity sales from data center growth at 1%-2% annually, the new growth should bolster the industry's financial measures, even given some regulatory lag.

Chart 2

U.S. electricity demand



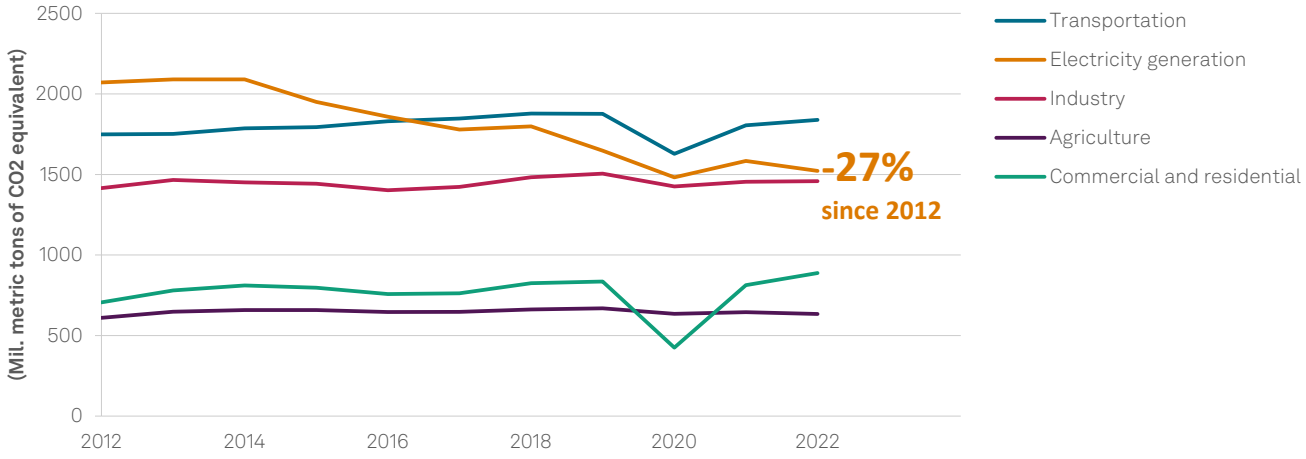
Source: CAGR--Compound annual growth rate. Data as of Nov. 30, 2025. Sources: U.S. Energy Information Administration (historical and 1.1% CAGR) and S&P Global Commodity Insights (1.7% CAGR).

In addition, customer bills are likely to benefit from this data center expansion, as the industry can distribute its fixed costs over a larger customer base. We view these developments as positive for the industry's credit quality but sustaining credit quality hinges on effectively managing the risks associated with this growth. These risks include: construction risks, data center service agreement risks, the expiration of the data center service agreements, the risk of bill increases for existing customers, and concentration risk. Managing these risks is central for the industry to maintain credit quality.

Capital spending is exploding. The industry's capital spending over the past decade has been growing at a compound annual growth rate at about 6%. The industry's spending was mostly focused on safety, reliability, and energy transition, successfully reducing its greenhouse gas emissions by about 27%.

Chart 3

GHG emission | Economic sector (2010-2022)

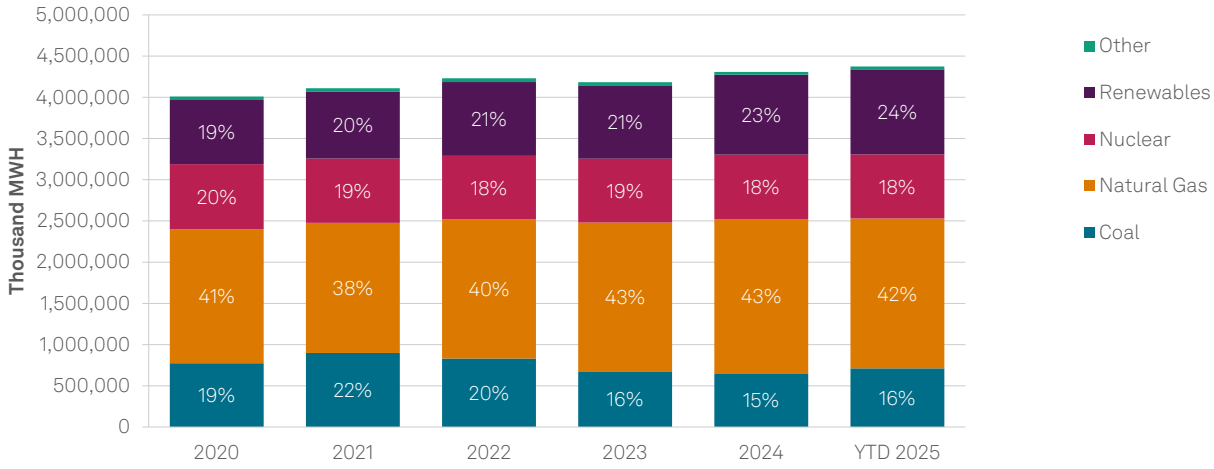


Data as of Oct. 31, 2025. Source: U.S. Environmental Protection Agency.

To accomplish its goals, the industry has transformed its generation, increasing its reliance on renewables (about 25% of total generation) and decreasing its reliance on coal fired generation (about 15% of total generation).

Chart 4

U.S. generation mix

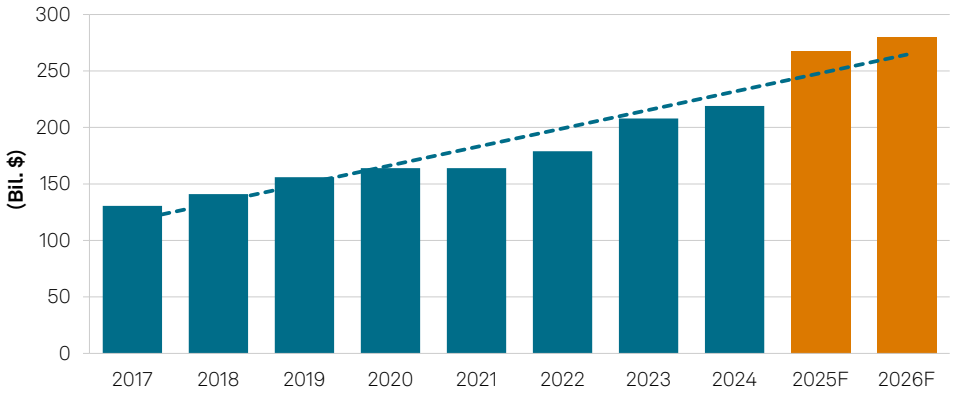


Data as of Oct. 31, 2025. Source: U.S. Energy Information Administration.

However, because of data center growth, we expect IOU capital spending will grow at unprecedented levels during the next decade. To maintain credit quality over this timeframe, the industry must fund these projects in a credit-supportive manner.

Chart 5

Rising capital spending

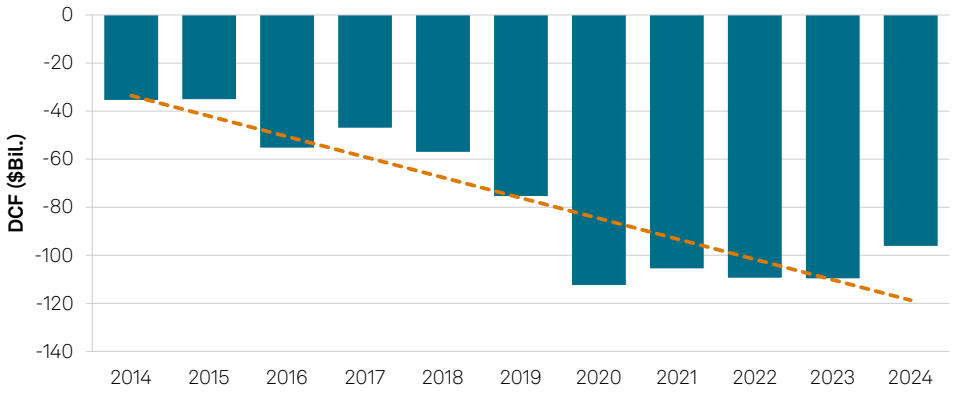


F--Forecast. Data as of Oct. 31, 2025. Sources: S&P Global Ratings and S&P Market Intelligence.

Robust cash flow deficits. The IOU industry consistently operates with high cash flow deficits at about $100 billion annually. The modest improvement is 2024 is mostly attributable to the transferability of tax credit that we expect will continue to increase through 2030.

Chart 6

High cash flow deficits

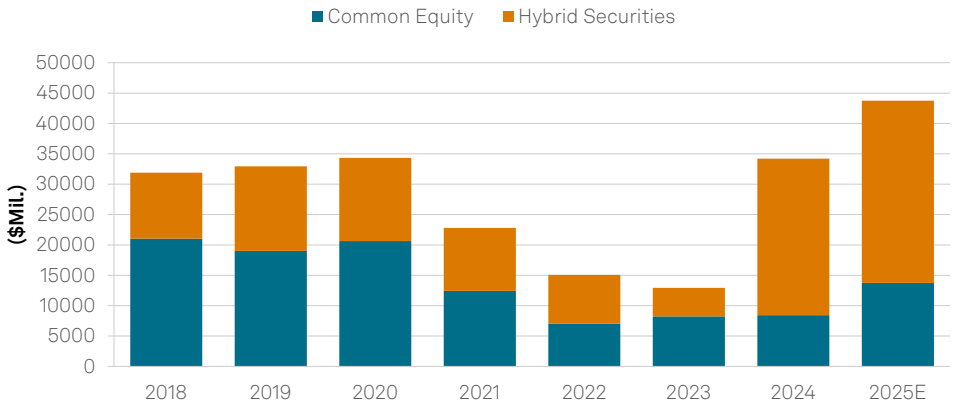


DCF – Discretionary cash flows. Data as of Oct. 31, 2025. Sources: S&P Global Ratings and S&P Market Intelligence.

Since 2020, the industry's funds from operations to debt has weakened by more than 150 basis points primarily because the industry's robust cash flow deficits that were not sufficiently funded in a credit-supportive manner. However, the industry's financial performance began stabilizing in 2024, reflecting record level of hybrid security issuance. In 2025 both the issuance of hybrid securities and common equity were materially higher than in 2024, increasing by about 16% and 90%, respectively.

Chart 7

Hybrids and common equity issuance

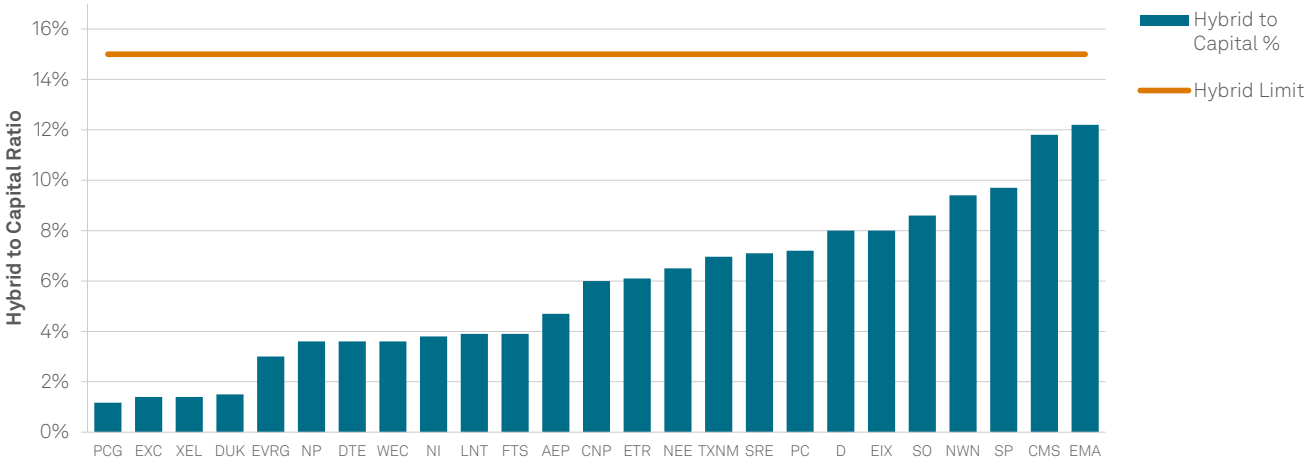


Data as of November 30, 2025. Source: S&P Market Intelligence.

Under our base case, we expect hybrid securities will remain key component for funding the industry's cash flow deficits over the next three years. S&P Global Ratings assesses equity content for hybrid securities so far as the securities account for less than 15% of total capitalization. Currently, most of the industry has considerable capacity, and as such we expect hybrid securities will continue to be heavily used over the near-term

Chart 8

Hybrid to total capital



Data as of Oct. 31, 2025. Source: S&P Global Ratings.
PCG—PG&E Corp. EXC—Exelon Corp. XEL—Xcel Energy Inc. DUK—Duke Energy Corp. EVRG—Evergy Inc. NP—Nevada Power Co. DTE—DTE Energy Co. WEC—WEC Energy Group Inc. LNT—Alliant Energy Corp. FTS—Fortis Inc. NI—NiSource Inc. AEP—American Electric Power Co. Inc. CNP—CenterPoint Energy. ETR—Entergy Corp. Inc. NEE—NextEra Energy Capital Holdings Inc. TXNM—TXNM Energy Inc. SRE—Sempra. PC—PacifiCorp. D—Dominion Energy Inc. EIX—Edison International. SO—The Southern Co. NWN—Northwest Natural Holding Co. SP—Sierra Pacific Power Co. CMS—CMS Energy Corp. EMA—EUSHI Finance Inc.

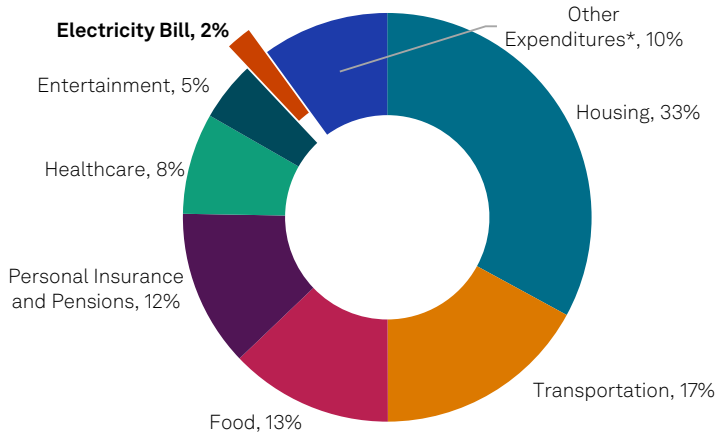
Managing the customer bill. One of the key credit risks for the IOU industry is to ensure that data centers are responsible for their share of electricity consumption. If existing customers subsidize the new data center customers, the existing customer bill will increase, which could strain a

utility's ability to manage regulatory risk. While the electricity bill for existing customers will nevertheless rise because of rising costs, the bill must not rise solely due to data center growth.

We assess the customer electric bill based on its relative size compared to total household income and based on the annual increase of the electric bill. Currently, on average, the U.S. electric bill only represents about 2% of household income.

Chart 9

2023 U.S. customer expenditures

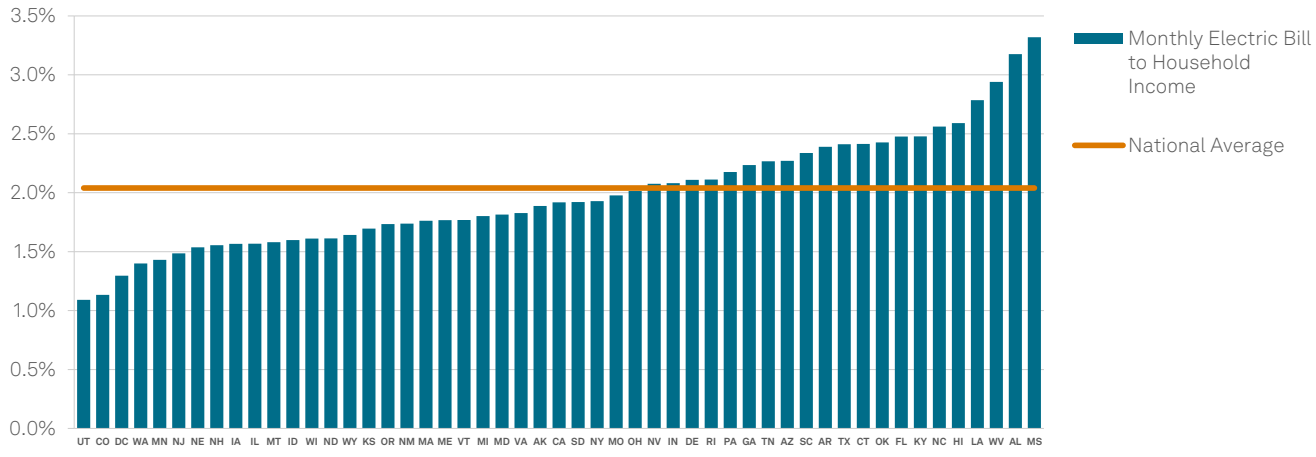


Sources: U.S. Energy Information Administration and U.S. Bureau of Labor Statistics.
*Other expenditures include alcoholic beverages, apparel and services, personal care products and services, reading, education, tobacco products and smoking supplies, cash contributions, and miscellaneous.

While the U.S. average is an important indicator, we assess each individual utility on a more granular basis, such as the electric bill's percentage of household income in each city, state, or regulatory jurisdiction.

Chart 10

Electric customer bill affordability by state



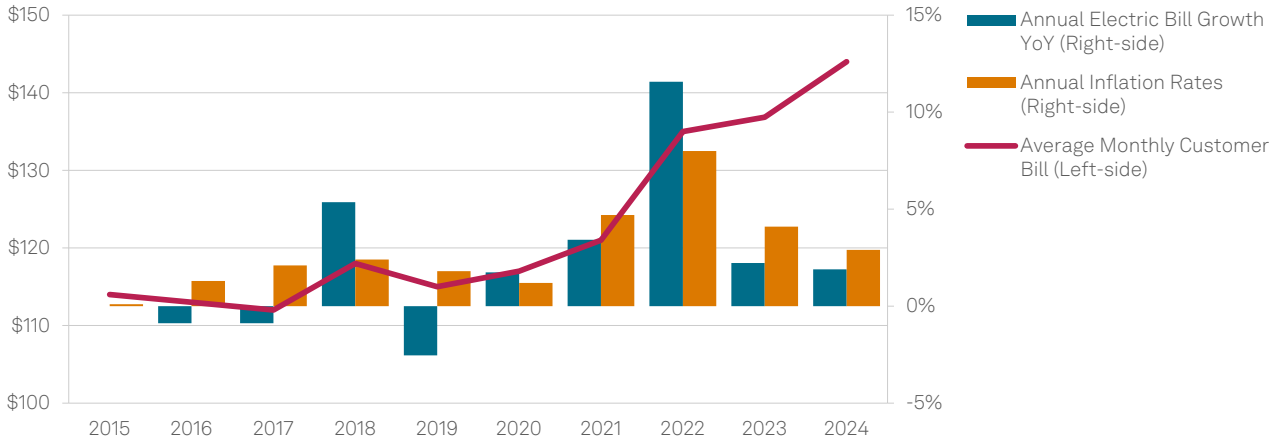
Data as of Oct. 31, 2025. Sources: Federal Reserve Bank of St. Louis and Energy Information Administration.

While states such as Utah, Colorado, Washington, Minnesota, and New Jersey, may have a relative lower electric bill, it is equally important for utilities, even in these states, to manage the

annual electric bill increases at or below inflation. For example, in 2022 electric bills increased by nearly 12%, driven by high commodity costs. Had these higher costs persisted, it likely would have resulted in higher risk for the entire IOU industry.

Chart 11

Inflation outpaces electric bill growth

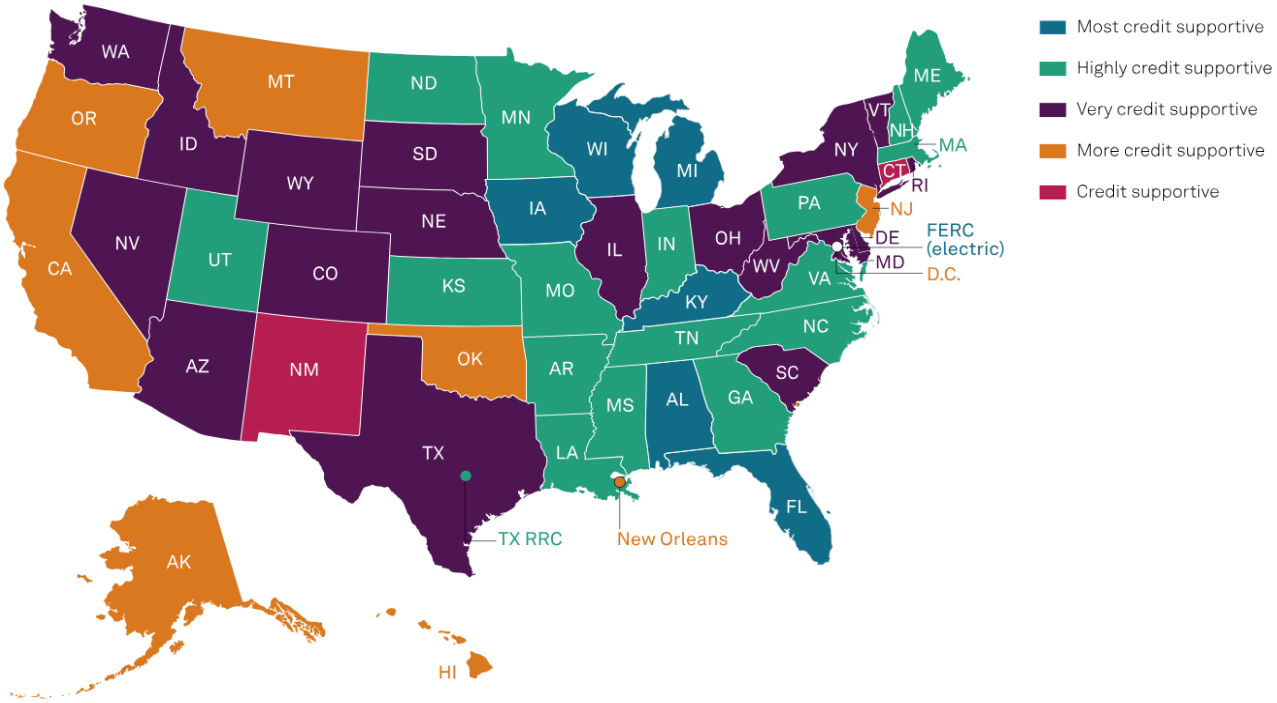


Data as of Oct. 31, 2025. Sources: U.S. Energy Information Administration and U.S. Bureau of Labor Statistics.
For 2015 to 2024, annual residential electric bills have increased at a 2.5% CAGR compared to a 2.8% CAGR for inflation.

Effective management of regulatory risk is critical for maintaining credit quality. We assess all of North America's regulatory jurisdictions as credit supportive or better, reflecting the industry's generally stable and predictable cash flows. Over the past decade much of the industry has implemented regulatory mechanisms such as decoupling, interim rates, capital trackers, formula rate plans, forward test years, muti-year rate case filings, and regulatory riders to significantly improve cash flow stability while minimizing regulatory lag.

Chart 12

U.S. regulatory jurisdiction assessments



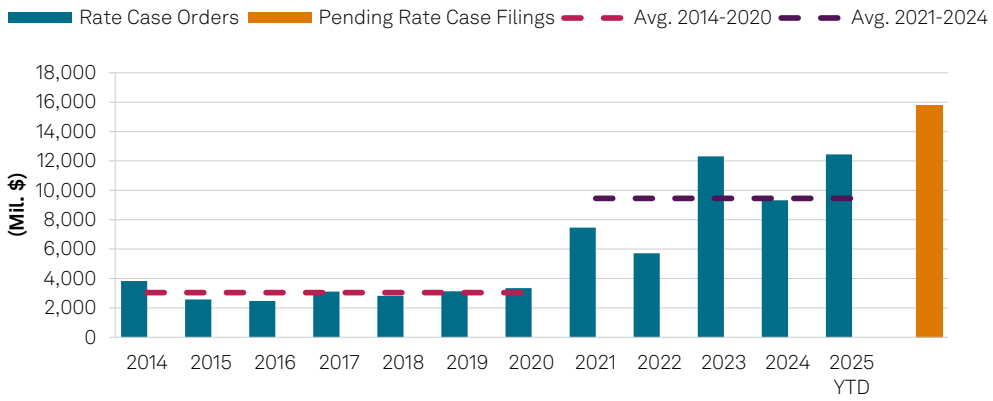
Data as of Nov. 4, 2025. Source: S&P Global Ratings.

Recently we revised upward our assessments for South Carolina, Missouri, and Arizona. Our improved assessment of South Carolina reflects the May 2025 House Bill 3309 that was signed into law, allowing electric utilities to request annual rate adjustments. In Missouri, the improvement reflected the April 2025 Senate Bill 4 that was signed into law, allowing natural gas, water, and sewer utilities to file rate cases using a future test period, which we expect will reduce regulatory lag. In Arizona, the improvement reflected constructive rate case orders and the approval of alternative regulation that may lead to formula rate plans that we believe would meaningfully reduce the regulatory lag.

Because of the industry's robust capital spending, its revenue requirement authorized in its rate case orders have more than doubled over the past decade, increasing the importance for the IOU industry to maintain and effectively manage regulatory risk.

Chart 13

Rate case orders reflect higher ROEs, inflation, and robust capital spending



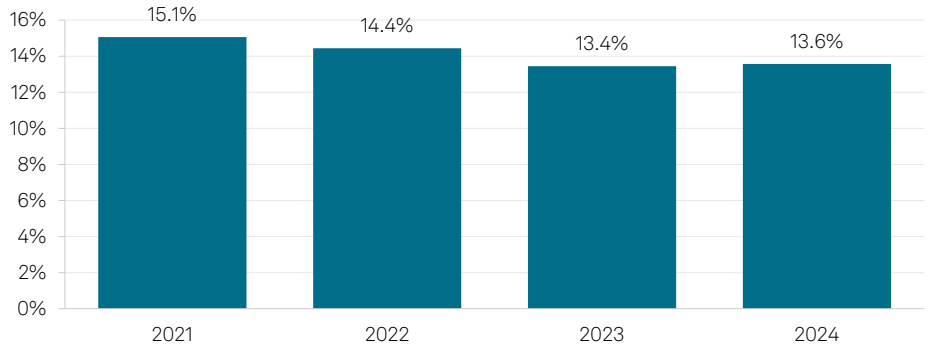
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights. YTD – Year to date and as of Nov. 30, 2025.

Credit metrics and financial policy

The industry's funds from operations (FFO) to debt was about 15% in 2021 and has gradually fallen to about 13.5%, primarily reflecting rising leverage. However, given the robust hybrid securities issued in 2024 and 2025 and the rising common equity issued in 2025, we believe financial measures have stabilized, despite the industry's year-over-year record capital spending.

Chart 14

Industry average FFO to debt

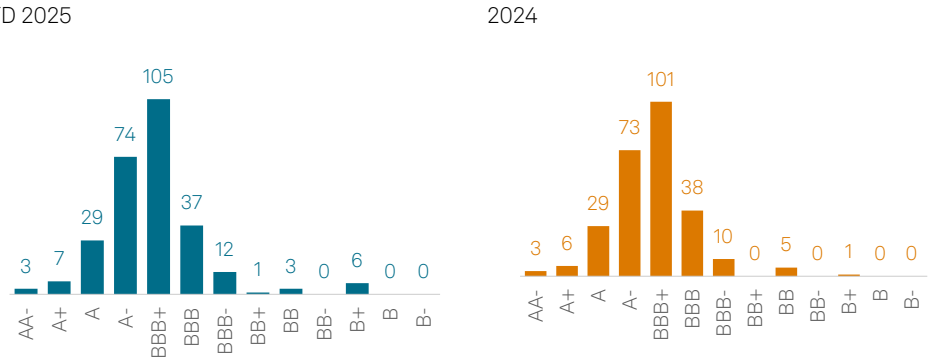


FFO– Funds from operations. Data as of Oct. 31, 2025. Sources: S&P Global Ratings and S&P Market Intelligence.

We also expect that the industry will continue to rely heavily on the transferability of tax credits and receive credit-supportive rate case orders that will allow the industry to generally maintain its credit quality despite rising capital spending. The industry's median rating is at 'BBB+' and we expect it will be maintained over the next several years.

Chart 15

Ratings distribution



Data as of November 30, 2025. Source: S&P Global Ratings.

Key risks or opportunities around the baseline

1. Wildfire risk.

Climate change is contributing to more frequent and severe weather events, including making conditions drier for longer periods. When high winds bring dry trees and other combustible materials into contact with power lines it raises the probability of a wildfire, raising the IOUs' wildfire risks and putting downward pressure on credit quality. Just in 2025 we downgraded four IOUs because of insufficient action to address wildfire risks.

2. Managing transmission and distribution (T&D)-only utilities could become more challenging.

Rising capacity costs are increasing the customer bill, raising the number of customer complaints, and potentially increasing the difficulties for T&D utilities to manage regulatory risk. We see this issue as a growing risk for the T&D utilities over the next several years.

3. Work order stoppages.

We assess the recent offshore wind work stoppages as negative for credit quality. In general, businesses expect consistent practices and steady implementation of rules. When work stoppages are suddenly announced, businesses lose confidence, putting future projects at risk. The industry is spending hundreds of billions of dollars in all type of generation including renewables, gas, and nuclear. The industry needs the confidence that regardless of the generation that is being built, after the project is fully approved, work stoppages will not be issued. These events could significantly increase a project's costs and even potentially derail the entire project.

Wildfire risks were never intended to be to be borne by the IOU industry. While the IOU industry continues to implement mitigation efforts, including system hardening and improving situational awareness, perfection is still not possible. Even if a utility proactively implements public safety power shutoff (PSPS) protocols--the deenergizing of power lines in advance of elevated wildfire conditions--a single severe wildfire could still devastate a utility's credit quality.

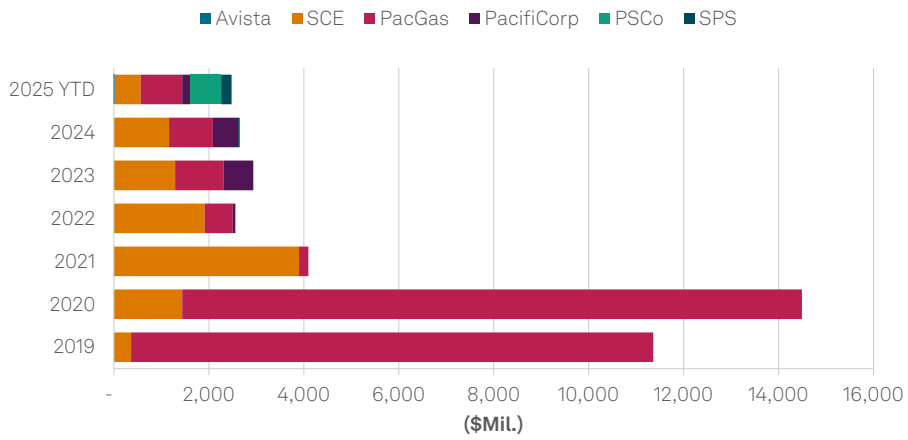
Reducing utility-related wildfire risk to zero is not feasible, due to resource constraints (both human and financial) and uncertainty associated with precisely where and when wildfire hazards may occur. Furthermore, IOUs were never designed to serve as the financial backstop for wildfire

risk. The industry was established about a century ago to ensure reliable service within a regulated monopoly construct. As such, a utility is typically authorized modest returns on equity, generally between 9% and 11%, at a leverage ratio that approximates 50%. At these levels the IOU industry lacks the financial flexibility to absorb large liabilities from increasingly frequent and severe wildfires, and was never equipped to handle such heightened risks. Other industries, such as insurance companies, which are generally characterized by lower financial leverage, are better positioned to take on these risks, having greater capacity to absorb high potential losses from extreme weather.

Wildfire risks remain high for many utilities. About 5% of the industry has already been named in wildfire lawsuits and wildfire related utility settlements continues to grow for the industry.

Chart 16

Lawsuit settlements attributable to wildfires



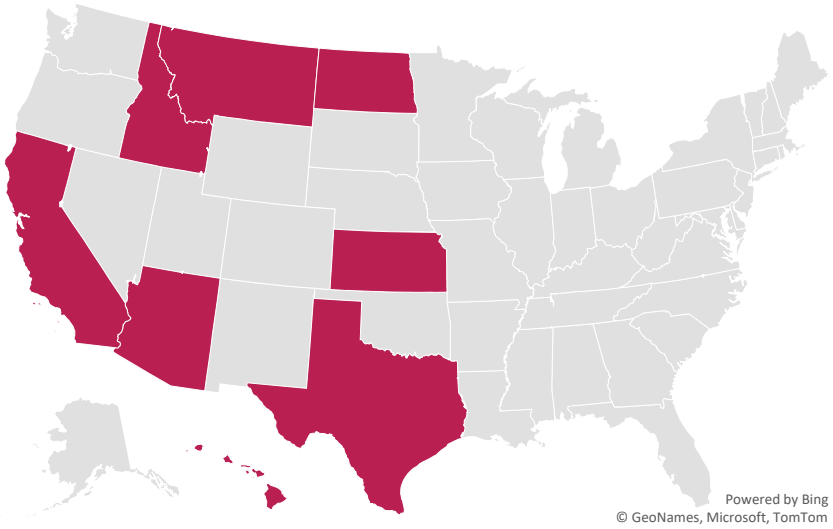
Sources: S&P Global Market Intelligence and issuer company documents, including 10-Ks and 10-Qs.

SCE—Southern California Edison Co. PacGas—Pacific Gas & Electric Co. PSCo—Public Service Co. of Colorado. Avista—Avista Utilities Inc. SPS—Southwestern Public Service Co. YTD—Year to date as of Oct. 31, 2025.

To reduce wildfire exposure many states enacted legislation in 2025. These enactments include approving and expanding a utility's wildfire mitigation plan, establishing a liability cap, authorizing securitization, increasing the funding of a wildfire fund, and allowing for self-insurance.

Chart 17

States that have recently enacted wildfire legislation to reduce risk

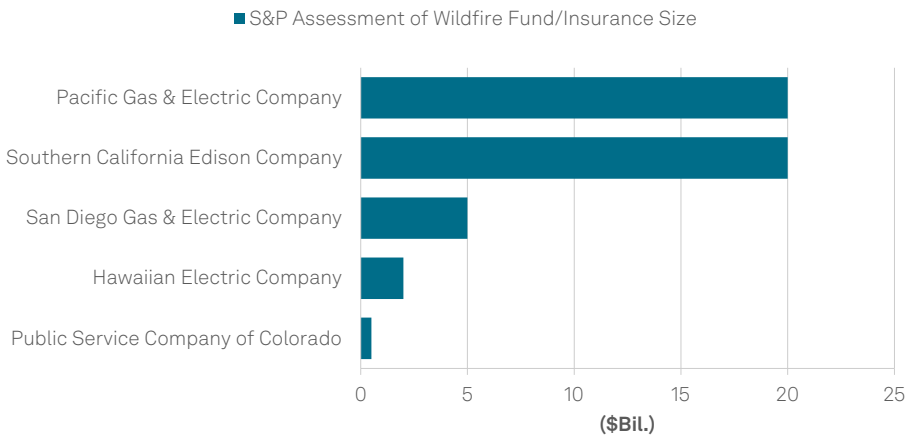


Data as of Oct. 31, 2025. Source: S&P Global Market Intelligence.

However, despite these improvements and much of industry implementing wildfire mitigation plans that include system hardening and investing in situational awareness, there are utilities with higher wildfire exposure than peers. In our view, these utilities based on their geography and topography, the effectiveness of its wildfire mitigation plan, the historical frequency and severity of wildfires within its service territory and projected future changes in wildfire conditions, the financial impact of past events, available insurance coverage, and existing legislative support require a minimum level of insurance and/or the size of a wildfire fund necessary for maintaining credit quality. Accordingly, the level of insurance or the size of a wildfire fund that is necessary for maintaining credit quality will greatly vary based on each utility's unique risk profile.

Chart 18

S&P assessment of wildfire fund/insurance size

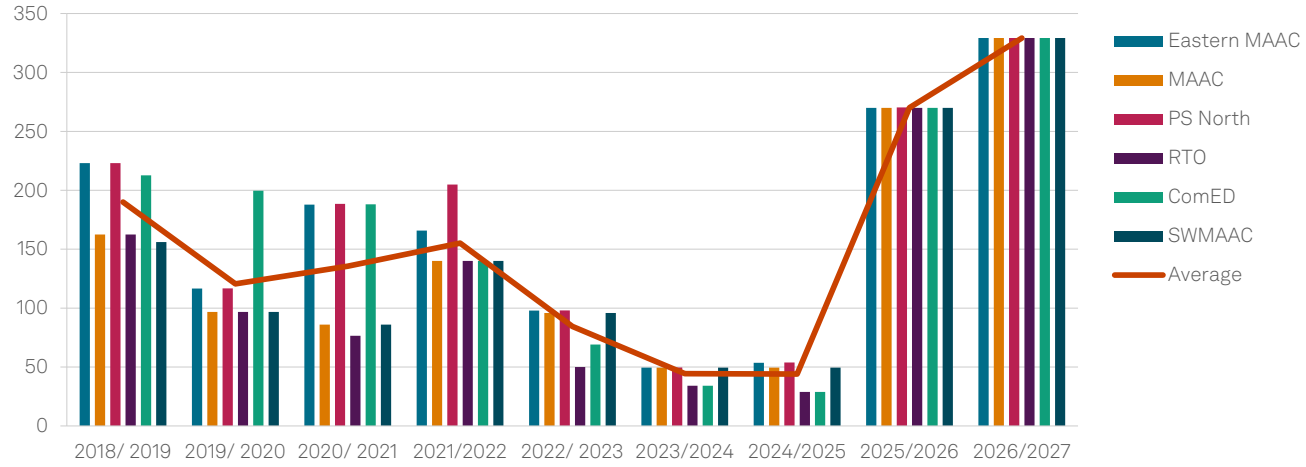


Data as of Oct. 31, 2025. Source: S&P Global Market Intelligence.

T&D rising risks. For T&D utilities, energy and capacity costs are a passed through to the customer bill. The T&D utility has no influence over these costs, but as these costs rise, customer complaints increase, usually affecting a utilities ability to effectively manage regulatory risk.

Chart 19

PJM Interconnection | Capacity Prices Higher For Longer



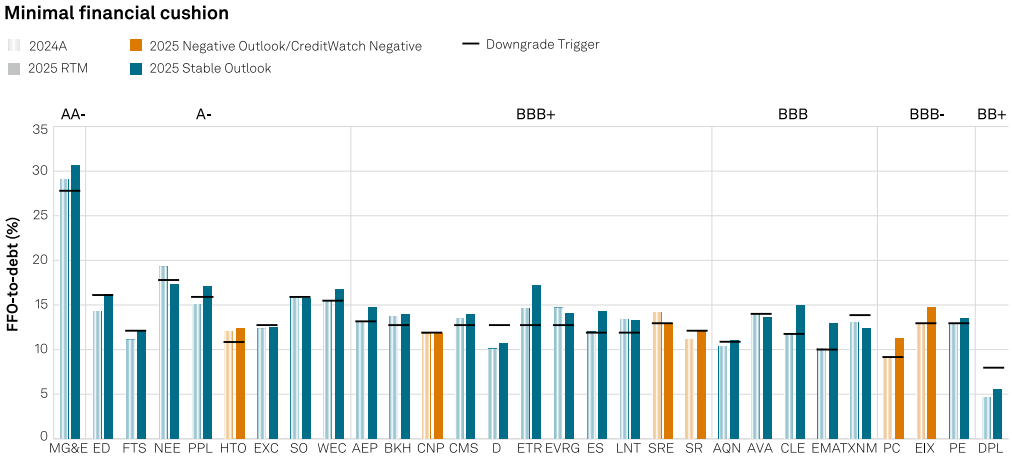
Data as of Oct. 31, 2025. Source: S&P Global Ratings.

The competitive process for electricity worked well over the past two decades when there was little growth because of conservation. However, as demand for electricity is now increasing and prices are rising, insufficient new generation is being built to lower the cost of electricity. As such, most T&D utilities are experiencing higher capacity and energy costs that are passed to their customers, increasing the overall electric bill. Unfortunately, there does not appear to be any near-term solution to this rising problem and T&D utility customers are likely to be paying an ever-increasing amount for electricity over the next several years. Some states are attempting to solve this problem by trying to pass legislation such that their utilities are allowed to build new regulated generation. However, this potential solution still has considerable challenges and even if enacted would likely take years to fully implement. As such, we expect that rising capacity costs will likely be a growing credit risk for the T&D utilities.

Minimal financial cushion from downgrade threshold. Because about 40% of the IOU industry is actively operating with minimal credit cushion, an unexpected event outside of the base case could result in a negative outlook or even a possible downgrade for many IOU utilities if financial levers are not quickly implemented to restore credit quality. While the industry's cash flows are highly predictable and stable, unexpected events beyond the base case still occur. Utilities with financial cushion from their downgrade threshold are more able to absorb these unexpected events while maintaining credit quality. However, utilities who strategically operate with minimal financial cushion must have financial levers that they can quickly implement, when necessary, to maintain credit quality.

Chart 20

Minimal financial cushion



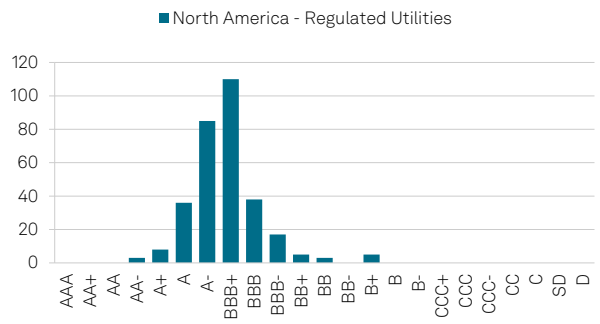
Data as of Dec. 15, 2025. FFO--Funds from operations. A – Actual. RTM – Rolling Twelve Months. MG&E—Madison Gas & Electric. LNT--Alliant Energy Corp. ED--Consolidated Edison Inc. FTS--Fortis Inc. NEE--NextEra Energy Inc. PPL--PPL Corp. HTO—H2O America. EXC – Exelon Corporation. SO—The Southern Co. SR--Spire Inc. WEC--WEC Energy Group, Inc. AEP--American Electric Power Co, Inc. BKH--Black Hills Corp. CNP--CenterPoint Energy Inc. CMS--CMS Energy Corp. D--Dominion Energy Inc. ETR--Entergy Corp. EVRG--Evergy Inc. PC — PacifiCorp. ES – Eversource Energy. SRE--Sempra. AQN--Algonquin Power & Utilities Corp. AVA--Avista Corp. CLE—Cleco Corporate Holdings LLC. EIX--Edison International. EMA--Emera Inc. TXNM—TXNM Energy Inc. PE--Puget Energy, Inc. DPL--DPL LLC. Source: S&P Global Ratings.
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Related Research

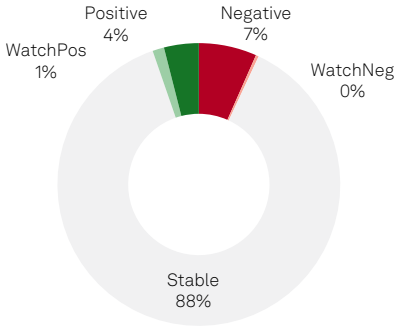
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- The Credit Impact: When North American Regulated Utilities Go Private, Nov. 06, 2025
- North American Utilities Regulatory Jurisdictions Update: South Carolina Assessment Revised; Other Notable Developments, Nov. 04, 2025
- The Burning Questions: North America's Investor-Owned Utility Wildfire Risks, Nov. 04, 2025
- The Phase-Out Of Renewable Energy Tax Credits Is Expected To Have A Neutral Impact On The Credit Quality Of Investor-Owned Utilities, Jul. 07, 2025

Ratings Trends

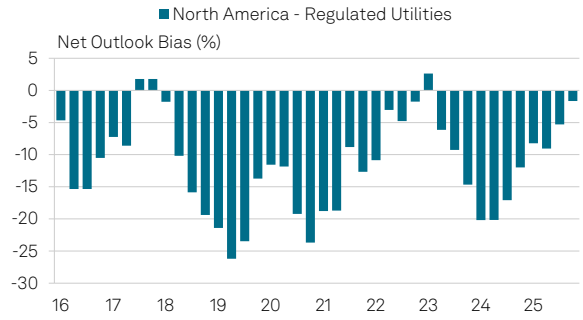
Ratings distribution



Ratings outlooks



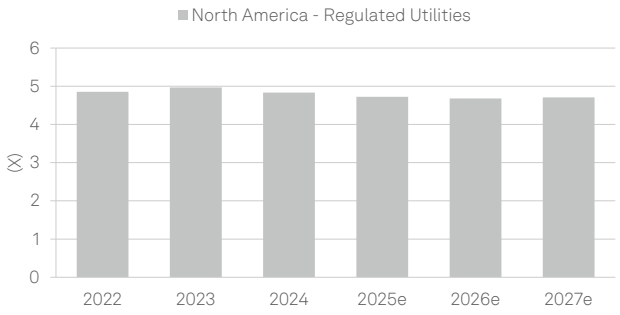
Ratings outlook net bias



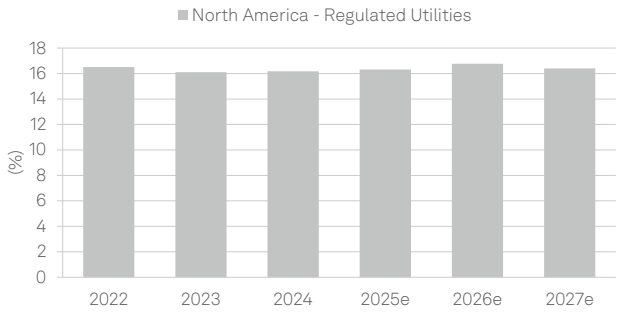
Source: S&P Global Ratings. Ratings data measured at quarter-end.

Industry Forecasts (Medians)

Debt/EBITDA (adjusted)



FFO/Debt (adjusted)



Source: S&P Global Ratings. e--estimate. FFO—Funds from operations. Data as of Dec. 31, 2025.

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FitchRatings

Corporates
Electric-Corporate
United States

Consumers Energy Company

Fitch Ratings expects Consumers Energy Company's (Consumers Energy) credit metrics to be temporarily pressured during the construction phase of new generation assets and funds from operations (FFO) leverage to average 4.7x through 2028, above Fitch's negative sensitivity. Leverage is higher than previously anticipated due to additional and expedited capital expenditures (capex) for new generation. Fitch expects FFO leverage to improve to 4.5x in 2029 once the assets are in service and included in rate base.

Key Rating Drivers

Capex Pressures Near-term Leverage: Consumers Energy's capex plans have been increased to $24 billion for 2026-2030, a 20% increase from the prior five-year plan. The increase is predominantly driven by new gas generation to replace retiring capacity and meet existing and anticipated load growth. The company expedited investment to manage global supply chain constraints, which will pressure credit metrics since these assets have later in-service dates. FFO leverage is expected to average 4.7x through 2028 before improving to 4.5x in 2029 when these assets are in rate base. Continued regulatory support is key to the company's ability to deleverage.

While not expected currently, restrictive regulatory outcomes, absent other mitigatory actions like credit supportive capital allocation, would keep leverage elevated for longer and could lead to negative rating actions.

Electric Rate Case: An electric rate case was filed in June 2025, with a revenue increase later revised to $423 millionbased on a 10.25% return on equity (ROE) filed later. Late March-2026, the MPSC approved a rate increase of $313 million, based on a 9.9% ROE, and a $24 million distribution deferral. The rate increase also includes the approved significant vegetation management and ERP related spending deferrals.

Load Growth and Potential Capex: Fitch expects Consumers Energy to benefit from increasing energy demand from manufacturing activity and data centers. Fitch estimates retail sales will grow by 2% to 3% annually through 2030. Fitch's current forecasts do not include major data center growth, beyond existing contracts. A further load increase is likely in the outer years given evolving data center activity in the state. While large load growth is cash flow accretive, the addition of large load customers would require additional capex.

Consumers Energy will file an Integrated Resource Plan in 2H26, which could highlight the need for additional investments for system resource adequacy . Continued ability to fund and recover associated investments in a credit-supportive manner would remain key to the ratings. Michigan's energy legislation allows for expanded incentives and improved economics for power purchase agreements (PPAs), providing investment flexibility. Continued ability to monetize tax credits on renewable projects and parent equity could provide further support.

Large Load Tariff: In November 2025, MPSC approved a specialized tariff for customers with new load exceeding 100 MW and set standards for contracts aimed at protecting existing customers against possible subsidization of data center costs. While individual rate design is subject to future rate case decisions, Fitch believes the order alleviates uncertainty in attracting and structuring new data center contracts and provides ratepayer protection in future rate cases. Key elements include minimum 15-year contracts and 80% minimum billing demand. To protect against stranded costs, a four-year termination notice and an exit fee with 50% default collateral, reduced over time is required.

Ratings

Long-Term IDR	A-
Short-Term IDR	F2
Senior Unsecured Debt - Long-Term Rating	A
Senior Secured Debt - Long-Term Rating	A+
Senior Unsecured Debt - Short-Term Rating	F2
Outlook	
Long-Term Foreign-Currency IDR	Stable

Click here for the full list of ratings

ESG and Climate

Highest ESG Relevance Scores	
Environmental	3
Social	3
Governance	3
2035 Climate Vulnerability Signal	42
Transition (Climate.VSt)	40
Physical (Climate.VSp)	22

Applicable Criteria

Parent and Subsidiary Linkage Rating Criteria (June 2025)
Sector Navigators – Addendum to the Corporate Rating Criteria (January 2026)
Corporate Hybrids Treatment and Notching Criteria (April 2025)
Corporate Rating Criteria (January 2026)
Corporates Recovery Ratings and Instrument Ratings Criteria (August 2024)

Related Research

Global Corporates Sector Forecasts Monitor: January 2026 (January 2026)
North American Utilities & Power Outlook 2026 (December 2025)
North American Utilities, Power & Gas 3Q25 Rating Trends Stable (October 2025)
North American Utilities Monitor: 1Q25 (June 2025)

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Michigan Regulation Remains Supportive: Fitch believes the regulatory framework remains constructive from a credit perspective, allowing for full pass-through of fuel costs and purchased power, forward-looking test years and a timely 10-month rate case resolution. Furthermore, Consumers Energy's authorized ROE of 9.8% for gas and 9.9% for electric compares favorably with industry averages. Fitch expects continued annual rate case filings. In June 2025, MPSC allowed a storm deferral account for recovery of costs incurred during the year, a positive for the storm-prone service territory.

Other Rate Case Activity: In December 2024, Consumers Energy filed a gas rate case with requested revenue increase later revised to $208 million , with a 10.25% return on equity (ROE) and a test year ending in October 2026. In September 2025, The Michigan Public Service Commission (MPSC) delivered a largely constructive decision authorizing a $158 million revenue increase, with a 9.8% allowed ROE, 10bps lower than previously authorized but still constructive and in line with a peer utility. In December 2025, Consumers Energy filed a gas rate case requesting a $240 million increase, with a 10.25% ROE. A decision is expected in 3Q26.

Coal Retirement Delayed: Consumers Energy's 1.4GW Campbell coal plants, scheduled to retire in May 2025, have been ordered to continue operations under various 90-day emergency orders by the Department of Energy. FERC's August 2025 decision is largely favorable as it allocates costs across MISO, which could alleviate increasing affordability concerns for the utility's customers in Michigan. However, while deferral has been allowed, FERC has not yet approved specific tariffs for recovery of costs. Fitch expects a constructive decision but there is no timeline for an outcome. The mechanism and timing of recovery would be key to prevent further pressure on leverage.

Parent/Subsidiary Linkage: There is parent-subsidiary rating linkage between CMS Energy and Consumers Energy. Fitch believes CMS Energy's consolidated credit profile is weaker than Consumers Energy's standalone credit profile (SCP). Emphasis is placed on the latter's status as a regulated entity. Legal ring-fencing is considered porous, given the general protections afforded by economic regulation. Access and control are also evaluated as porous. CMS Energy centrally manages the treasury function; however, both entities issue their own long-term debt. Fitch will limit the difference between the Long-Term IDRs of CMS Energy and Consumers Energy to two notches.

Rating Sensitivities

Factors that Could, Individually or Collectively, Lead to Negative Rating Action/Downgrade

- FFO leverage expected to exceed 4.5x on a sustained basis;
- A material deterioration of the Michigan regulatory environment;
- A downgrade to CMS Energy's Long-Term IDR.

Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade

- A positive rating action on Consumers Energy would also require an equally positive rating action on its parent, CMS, under Fitch's Parent and Subsidiary Linkage Criteria;
- FFO leverage expected to be less than 3.5x on a sustained basis.

Issuer Profile

CMS Energy is an energy holding company whose principal operating subsidiary is Consumers Energy Company, a regulated integrated electric and natural gas distribution utility in Michigan.

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Financial Summary

(USD Mil.)	2022	2023	2024	2025
Gross revenue	8,116	7,127	7,050	7,986
EBITDA	2,260	2,345	2,538	2,857
CFO (Fitch-defined)	954	2,387	2,328	2,115
FFO	2,052	2,144	2,223	2,083
Debt	10,230	10,613	11,589	12,975
FFO leverage (x)	4.4	4.2	4.4	5.0
FFO interest coverage (x)	8.1	6.2	5.9	5.2
EBITDA leverage (x)	4.5	4.5	4.6	4.5

Source: Fitch Ratings, Fitch Solutions

Corporate Rating Tool Inputs and Scores

Fitch Scored the Issuer as follows, Using our Corporate Rating Tool (CRT) to Produce the STANDALONE Credit Profile (SCP):

- Business and financial profile factors (assessment, relative importance): Management (bbb, Lower), Sector Characteristics (a-, Higher), Market and Competitive Positioning (a-, Moderate), Diversification and Asset Quality (a, Moderate), Company Operational Characteristics (a-, Moderate), Profitability (bbb, Lower), Financial Structure (bbb+, Higher), and Financial Flexibility (a-, Moderate).
- The quantitative financial subfactors are based on custom CRT financial period parameters: 50% weight for the forecast year 2029 and 50% for the forecast year 2030.
- The Governance assessment of 'Good' results in no adjustment.
- The Operating Environment assessment of 'aa-' results in no adjustment.
- The SCP is 'a-'.

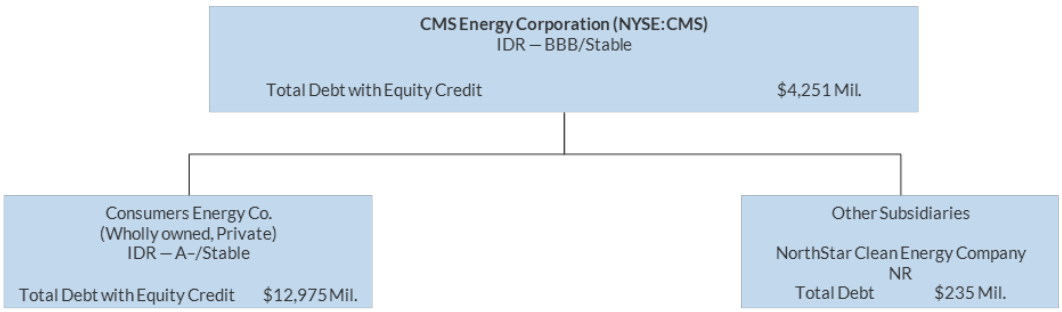
To Derive the IDR:

- Application of Fitch's Parent Subsidiary Linkage Considerations Rating Criteria results in a consolidated profile+2 approach.

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Simplified Group Structure Diagram

Organizational and Debt Structure — CMS Energy Corporation
(USD Mil., as of Dec. 31, 2025)



IDR – Issuer Default Rating. NR – Not rated.
Source: Fitch Ratings, Fitch Solutions, CMS Energy Corporation

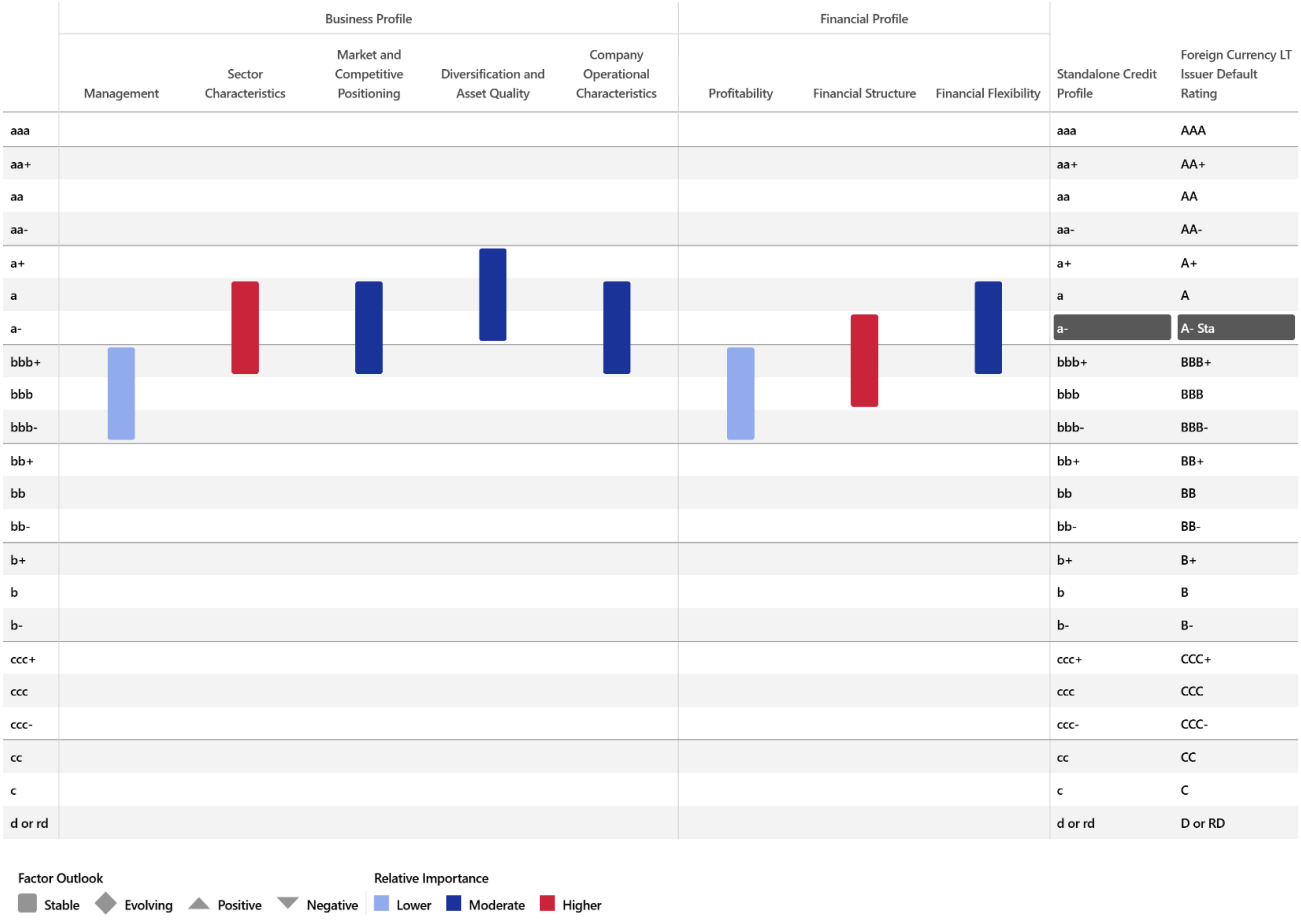
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FitchRatings

Corporates
Electric-Corporate
United States

Ratings Navigator

North American Utilities



Additional Adjustments to the Standalone Credit Profile

	Assessment	Impact
Weakest link considerations	Not applied	0
Additional sector considerations	Not applied	0
B+ to CC considerations	Not applied	0
Governance	Good	0
Operating environment	aa-	0
Other risk elements	Not applied	0
Calibration	Not applied	0
Standalone Credit Profile		**a-**
Parent Subsidiary Linkage Considerations	Consolidated Profile +2	**A-**
Government Related Entities Considerations	Not applied	-
Country Ceiling Considerations	Not applied	0
Other Critical Considerations	Not applied	0

Factor/Subfactor	Score/Outlook/Importance Description
Management	bbb/stable/lower

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Factor/Subfactor	Score/Outlook/Importance	Description
Risk tolerance	bbb/moderate	Management committed to conservative risk profile. Only modest/short-term deviations from strategy allowed.
Management strategy	bbb/moderate	Good track record of implementing coherent and stable strategy.
Management quality	bbb/moderate	Experienced management or proven track record. Management composition is broadly stable. No evidence of material risk management weaknesses.

Factor/Subfactor	Score/Outlook/Importance	Description
Sector characteristics	a-/stable/higher	
Regulatory environment	a/moderate	Track record of transparent and predictable regulation.
Mechanisms supportive of creditworthiness	a-/moderate	Effective regulatory ring-fencing.
Cost and investment recovery	a-/moderate	Minimal lag to recover capital and operating costs.
Trend in authorized roes	a/moderate	Above-average authorized ROE.
Market structure	a-/moderate	Well-established market structure with complete transparency in price-setting mechanisms.

Factor/Subfactor	Score/Outlook/Importance	Description
Market and competitive positioning	a-/stable/moderate	
Underlying supply mix	a-/moderate	Extremely low cost and flexible supply.
Consumption growth potential	a/moderate	Economically vibrant market or service territory with strong sales growth.
Supply demand dynamics	a-/moderate	Beneficial outlook for prices/rates.

Factor/Subfactor	Score/Outlook/Importance	Description
Diversification and asset quality	a/stable/moderate	
Asset diversification	a/moderate	High-quality and/or large-scale diversified assets.
Geographic diversification	a/moderate	Favorable location or high geographic diversity.
Customer diversification	a+/moderate	Favorable customer mix.

Factor/Subfactor	Score/Outlook/Importance	Description
Company operational characteristics	a-/stable/moderate	
Operational reliability	a/moderate	Track record of reliable, low-cost operations.
Capex intensity	bbb+/moderate	Moderate reinvestments requirements in established technologies.
Cost competitiveness	a+/moderate	Complete pass-through of commodity costs.
Exposure to weather risk	bbb+/moderate	Resilient asset base, manageable exposure to wildfire, hurricane or other weather-related natural disasters supported by effective legal/regulatory constructs.
Environmental exposure	bbb+/moderate	Limited or manageable exposure to environmental regulations.

Factor/Subfactor	Score/Outlook/Importance	Description
Profitability	bbb/stable/lower	
Free cash flow	bb+/moderate	Structurally negative FCF across the investment cycle.
Volatility of profitability	a/moderate	Higher stability and predictability of profits relative to utility peers.

Factor/Subfactor	Score/Outlook/Importance	Description
Financial structure	bbb+/stable/higher	
Ebitda leverage (x)	bb/lower	4.75
Ffo leverage (x)	bbb+/higher	5.0

Factor/Subfactor	Score/Outlook/Importance	Description
Financial flexibility	a-/stable/moderate	

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Factor/Subfactor	Score/Outlook/Importance	Description
Financial access	a/moderate	Unequivocal access through the cycle to: Local financial markets with FMD of 'a' and above, or International financial markets with (primarily) FMD of 'a' and above. If the issuer is an infrequent/ untested issuer, the issuer must be very likely to be able to freely access these markets through the cycle.
Liquidity	bbb+/moderate	One-year liquidity ratio above 1.25x. Well-spread maturity schedule of debt but funding may be less diversified.
Ffo interest coverage (x)	bbb+/moderate	4.5

Factor/Subfactor	Score/Outlook/Importance	Description
Governance	Good/—/—	
Ownership and decision-making concentration	Good/moderate	No concentration in ownership and/or decision-making. Presence of effective checks and balances. Key person risk is immaterial. Decision-making is defensible from a governance perspective.
Group structure transparency and contagion risk	Good/moderate	Transparent group structure. No contagion risks.
Information quality/transparency	Good/moderate	Timely and good provision of financial and operational information, facilitating the analysis of the credit profile.

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Parent Subsidiary Linkage Analysis

Key Risk Factors and Notching Approach

Parent	CMS Energy Corporation
Parent LT IDR	BBB
Subsidiary	Consumers Energy Company
Subsidiary LT IDR	A-
Path	Stronger Subsidiary
Legal ring-fencing	Porous
Access and control	Porous
Notching matrix outcome	Parent consolidated profile+2
Override applied	No
Notching approach	—

LT IDR – Long-Term Issuer Default Rating
Source: Fitch Ratings

Stronger Subsidiary Maximum Rating Matrix

Access and control	Open	Porous	Insulated
With open ring-fencing	Parent consolidated profile	Parent consolidated profile+1	Parent consolidated profile+2[b]
With porous ring-fencing	Parent consolidated profile+1	Parent consolidated profile+2[b]	Parent consolidated profile+2[b]
With insulated ring-fencing	[a]	Standalone	Standalone

[a]It is unlikely that considerations for "insulated" legal ring-fencing would coexist with the conditions outlined under "open" for access and control. It is more likely that other factors relevant to legal ring-fencing or access and control, but not within this table, would move either one, or both, of the individual Linkage Factor Assessments (LFAs) to a "porous" level that would lead to a Parent consolidated+1, Parent consolidated+2 or standalone outcome. [b]Notching is capped at the subsidiary's Standalone Credit Profile.
Source: Fitch Ratings

Fitch's Key Rating-Case Assumptions

- Constructive regulatory environment in Michigan with authorized ROEs for both electric and gas utility operations in line with recent rate cases;
- Gas rate case decision in 3Q26, constructive in line with other recent rate cases;
- Annual rate case filings;
- Largely flat annual natural gas sales growth;
- Electric sales growth ranging 2%-3% over 2026-2030;
- Total utility capex in line with management's assumptions;
- Normal weather;
- Tax credit transfers of $1.3 billion over 2026-2030 for CMS

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Liquidity and Debt Structure

Consumers Energy's $500 million commercial paper (CP) program is supported by its $1.1 billion RCF maturing November 2030, almost fully undrawn as of Dec. 31, 2025. It also had a separate $300 million RCF, fully available and $10 million available out of its $350 million LC facilities.

Consumers Energy had $25 million in unrestricted cash at Dec. 31, 2025. Consumers Energy has bond maturities of $115 million in 2026, $135 million in 2027, $725 million in 2028 and $1,150 million in 2029.

Fitch's views these maturities as manageable given the history of successful refinancing and expected continued access to capital markets. As of Dec. 31, 2025, Consumers Energy was compliant with its consolidated debt/capitalization covenants of 65%.

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Liquidity and Debt Maturities

Cash and Maturities Report

(USD Mil.)	December 31, 2024	December 31, 2025
Total cash and cash equivalents	119	111
Short-term investments	—	—
Less not readily available cash and cash equivalents	75	86
Fitch-defined readily available cash and cash equivalents	**44**	**25**
Availability under committed lines of credit	1,199	1,060
Total liquidity	1,243	1,085
LTM EBITDA after associates and minorities	2,538	2,857
LTM FCF	-1,309	-2,099

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Scheduled Debt Maturities

(USD Mil.)	December 31, 2025
2026	121
2027	135
2028	725
2029	1,150
2030	700
Thereafter	10,144
Total	**12,975**

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

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Financial Data

(USD Mil.)	2022	2023	2024	2025
Summary income statement				
Gross revenue	8,116	7,127	7,050	7,986
Revenue growth (%)	16.2	-12.2	-1.1	13.3
EBITDA before income from associates	2,260	2,345	2,538	2,857
EBITDA margin (%)	27.9	32.9	36.0	35.8
EBITDA after associates and minorities	2,260	2,345	2,538	2,857
EBIT	1,212	1,249	1,463	1,726
EBIT margin (%)	14.9	17.5	20.8	21.6
Gross interest expense	-316	-416	-467	-541
Pretax income including associate income/loss	1,085	1,028	1,209	1,417
Summary balance sheet				
Readily available cash and equivalents	43	35	44	25
Debt	10,230	10,613	11,589	12,975
Net debt	10,187	10,578	11,545	12,950
Summary cash flow statement				
EBITDA	2,260	2,345	2,538	2,857
Cash interest paid	-290	-401	-445	-493
Cash tax	2	-31	19	-161
Dividends received less dividends paid to minorities (inflow/outflow)	—	—	—	—
Other items before FFO	73	203	66	-120
FFO	2,052	2,144	2,223	2,083
FFO margin (%)	25.3	30.1	31.5	26.1
Change in working capital	-1,098	243	105	32
CFO (Fitch-defined)	954	2,387	2,328	2,115
Total non-operating/nonrecurring cash flow	—	—	—	—
Capex	-2,239	-3,060	-2,842	-3,314
Capital intensity (capex/revenue) (%)	27.6	42.9	40.3	41.5
Common dividends	-771	-695	-795	-900
FCF	-2,056	-1,368	-1,309	-2,099
FCF margin (%)	-25.3	-19.2	-18.6	-26.3
Net acquisitions and divestitures	—	—	124	—
Other investing and financing cash flow items	-87	-121	-367	-112
Net debt proceeds	1,474	1,010	880	1,283
Net equity proceeds	685	475	735	920
Total change in cash	16	-4	63	-8
Calculations for forecast publication				
Capex, dividends, acquisitions and other items before FCF	-3,010	-3,755	-3,513	-4,214
FCF after acquisitions and divestitures	-2,056	-1,368	-1,185	-2,099
FCF margin after net acquisitions (%)	-25.3	-19.2	-16.8	-26.3
Gross Leverage ratios (x)				
EBITDA leverage	4.5	4.5	4.6	4.5
FFO leverage	4.4	4.2	4.4	5.0
(CFO-capex)/debt (%)	-12.6	-6.3	-4.4	-9.2
Net Leverage ratios (x)				
EBITDA net leverage	4.5	4.5	4.6	4.5
FFO net leverage	4.4	4.2	4.4	5.0
(CFO-capex)/net debt (%)	-12.6	-6.4	-4.5	-9.3

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(USD Mil.)	2022	2023	2024	2025
Coverage ratios (x)				
EBITDA interest coverage	7.8	5.8	5.7	5.8
FFO interest coverage	8.1	6.2	5.9	5.2
FFO fixed-charge coverage	8.1	6.2	5.9	5.2

CFO – Cash flow from operations
Source: Fitch Ratings, Fitch Solutions

How to Interpret the Forecast Presented

The forecast presented above is based on Fitch Ratings' internally produced, conservative rating case forecast. It does not represent the forecast of the rated issuer. The forecast set out above is only one component used by Fitch Ratings to assign a rating or determine a rating outlook, and the information in the forecast reflects material but not exhaustive elements of Fitch Ratings' rating assumptions for the issuer's financial performance. As such, it cannot be used to establish a rating, and it should not be relied on for that purpose. Fitch Ratings' forecasts are constructed using a proprietary internal forecasting tool, which employs Fitch Ratings' own assumptions on operating and financial performance that may not reflect the assumptions that you would make. Fitch Ratings' own definitions of financial terms such as EBITDA, debt or free cash flow may differ from your own such definitions. Fitch Ratings may be granted access, from time to time, to confidential information on certain elements of the issuer's forward planning. Certain elements of such information may be omitted from this forecast, even where they are included in Fitch Ratings' own internal deliberations, where Fitch Ratings, at its sole discretion, considers the data may be potentially sensitive in a commercial, legal or regulatory context. The forecast (as with the entirety of this report) is produced strictly subject to the disclaimers set out at the end of this report. Fitch Ratings may update the forecast in future reports but assumes no responsibility to do so. Original financial statement data for historical periods is processed by Fitch Solutions on behalf of Fitch Ratings. Key financial adjustments and all financial forecasts credited to Fitch Ratings are generated by rating agency staff.

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Summary of Financial Adjustments

- Consumers Energy's securitization debt is removed from all financial metric calculations;
- Consumers Energy's preferred stock is given 50% equity credit in the utility's financial metric calculations

Fitch Adjusted Financials

(USD Mil., as of December 31, 2025)	Notes and formulas	Standardised values	Fair value and other debt adjustments	Lease treatment	Other adjustments	Adjusted values
Income statement summary						
Revenue		8,132	—	—	-146	7,986
EBITDA	(a)	3,023	—	-20	-146	2,857
Depreciation and amortization		-1,254	—	6	117	-1,131
EBIT		1,769	—	-14	-29	1,726
Balance sheet summary						
Debt	(b)	13,461	99	—	-585	12,975
Of which other off-balance-sheet debt		—	—	—	—	—
Lease-equivalent debt		—	—	—	—	—
Lease-adjusted debt		13,461	99	—	-585	12,975
Readily available cash and equivalents	(c)	25	—	—	—	25
Not readily available cash and equivalents		86	—	—	—	86
Cash flow summary						
EBITDA	(a)	3,023	—	-20	-146	2,857
Dividends received from associates less dividends paid to minorities	(d)	—	—	—	—	—
Interest paid	(e)	-526	—	14	19	-493
Interest received	(f)	—	—	—	—	—
Preferred dividends paid	(g)	-2	—	—	—	-2
Cash tax paid		-161	—	—	—	-161
Other items before FFO		-130	—	—	10	-120
FFO	(h)	2,206	—	-6	-117	2,083
Change in working capital		32	—	—	—	32
CFO	(i)	2,238	—	-6	-117	2,115
Non-operating/nonrecurring cash flow		—	—	—	—	—
Capex	(j)	-3,314	—	—	—	-3,314
Common dividends paid		-900	—	—	—	-900
FCF		-1,976	—	-6	-117	-2,099
Gross leverage (x)						
EBITDA leverage	b/(a+d)	4.5	—	—	—	4.5
FFO leverage	b/(h-e-f-g)	5.0	—	—	—	5.0
(CFO-capex)/debt (%)	(i+j)/b	-7.9	—	—	—	-9.2
Net leverage (x)						
EBITDA net leverage	(b-c)/(a+d)	4.5	—	—	—	4.5
FFO net leverage	(b-c)/(h-e-f-g)	5.0	—	—	—	5.0
(CFO-capex)/net debt (%)	(i+j)/(b-c)	-8.0	—	—	—	-9.3
Coverage (x)						
EBITDA interest coverage	(a+d)/(-e)	5.7	—	—	—	5.8
FFO interest coverage	(h-e-f-g)/(-e-g)	5.2	—	—	—	5.2

CFO – Cash flow from operations
Note: The standardised items presented above are based on Fitch's taxonomy for the given sector and region.
Reported items may not match the Fitch taxonomy, but they are captured into corresponding lines accordingly.
Debt includes other off-balance-sheet debt.
Debt in the standardised values column excludes lease liabilities of USD105 million.
Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

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Peer Analysis

Consumers Energy's credit profile is comparable to peers such as DTE Electric Company (DTEE; A-/Stable), Northern States Power Company-Minnesota (NSP-Minnesota; A-/Stable) and Northern States Power Company-Wisconsin (NSP-Wisconsin; A-/Stable), and Public Service Company of Colorado (A-/Stable). All four are regulated utilities with single state operations albeit in generally constructive environments.

Fitch forecasts Consumer Energy's FFO leverage to remain elevated, averaging 4.7x near term, the improving to 4.5x over 2029-2030. This is better than the average 4.6x through 2028 projected for the pure gas utility, DTE Gas Company (BBB+/Stable). Financial metrics at other electric peers are stronger, with leverage forecast to average 3.8x through 2028 at DTEE, 4.0x-4.4x for NSP-Wisconsin, and 3.5x-4.0x for NSP-Minnesota through 2029, making them well positioned for their ratings.

Navigator Peer Comparison

Issuer		Business profile (Score/Relative Importance)					Financial profile (Score/Relative Importance)		
Name	IDR/Outlook	Management	Sector Characteristics	Market and Competitive Positioning	Diversification and Asset Quality	Company Operational Characteristics	Profitability	Financial Structure	Financial Flexibility
Consumers Energy Company	A-/Stable	bbb	a-	a-	a	a-	bbb	bbb+	a-
DTE Electric Company	A-/Stable	bbb	a-	bbb+	bbb+	bbb+	bbb+	bbb+	a-
DTE Gas Company	BBB+/Stable	bbb	a-	bbb	bbb+	bbb+	bbb+	bbb+	bbb
Northern States Power Company-Minnesota	A-/Stable	bbb+	a-	bbb	bbb+	bbb	bbb+	a-	a-
Northern States Power Company-Wisconsin	A-/Stable	bbb+	a-	bbb	bbb+	bbb	bbb+	a-	a-
Public Service Company of Colorado	A-/Stable	bbb+	a-	a	a-	bbb+	a-	bbb+	a
Southwestern Public Service Company	BBB/Stable	bbb+	bbb-	bbb+	bbb+	bbb	bbb+	bbb+	a-

Relative importance: Higher Moderate Lower

Source: Fitch Ratings

Post-Factor Assessment Analytical Adjustments and Overlays

Issuer			Analytical Adjustment			Governance	Operating Environment	Qualitative Overlay		
Name	IDR/Outlook	Factor Assessment Outcome	Additional Sector	Weakest Link	B+ to CC	Rating Impact	Rating Impact	Other Risk Elements	Calibration	Final SCP
Consumers Energy Company	A-/Stable	a-	-	-	-	-	-	-	-	a-
DTE Electric Company	A-/Stable	a-	-	-	-	-	-	-	-	a-
DTE Gas Company	BBB+/Stable	bbb+	-	-	-	-	-	-	-	bbb+
Northern States Power Company-Minnesota	A-/Stable	a-	-	-	-	-	-	-	-	a-
Northern States Power Company-Wisconsin	A-/Stable	a-	-	-	-	-	-	-	-	a-
Public Service Company of Colorado	A-/Stable	a-	-	-	-	-	-	-	-	a-
Southwestern Public Service Company	BBB/Stable	bbb	-	-	-	-	-	-	-	bbb

SCP - Standalone Credit Profile
Source: Fitch Ratings

Peer Financial Summary

Company	Issuer Default Rating	Financial statement date	Gross revenue (USD Mil.)	FFO (USD Mil.)	FFO leverage (x)	FFO interest coverage (x)	EBITDA leverage (x)
Consumers Energy Company	A-						
	A-	2025	7,986	2,083	5.0	5.2	4.5
	A-	2024	7,050	2,223	4.4	5.9	4.6
	A-	2023	7,127	2,144	4.2	6.2	4.5
DTE Electric Company	A-						
	A-	2025	6,885	2,788	4.0	6.3	4.3
	A-	2024	6,277	2,537	3.9	6.1	4.2
	A-	2023	5,804	1,968	4.5	5.6	4.1
DTE Gas Company	BBB+						
	BBB+	2025	2,033	593	4.4	5.7	4.4
	BBB+	2024	1,783	507	4.7	5.5	4.4
	BBB+	2023	1,726	560	4.0	6.7	3.9
Northern States Power Company-Minnesota	A-						
	A-	2024	5,767	1,799	3.9	6.3	4.3

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	A-	2023	6,043	1,985	3.3	7.3	3.9
	A-	2022	6,684	1,587	3.9	6.7	3.7
Northern States Power Company-Wisconsin	A-						
	A-	2024	1,131	301	4.1	6.5	3.6
	A-	2023	1,177	295	3.7	6.8	3.3
	A-	2022	1,201	270	3.7	7.4	3.2
Public Service Company of Colorado	A-						
	A-	2024	5,272	1,794	4.2	6.3	4.4
	A-	2023	5,519	1,650	4.1	6.4	4.2
	A-	2022	5,708	1,448	4.2	6.2	4.0
Southwestern Public Service Company	BBB						
	BBB	2024	1,939	948	3.4	7.2	4.1
	BBB	2023	2,152	613	4.6	5.6	4.1
	BBB	2022	2,426	759	3.7	6.5	4.0

Source: Fitch Ratings, Fitch Solutions

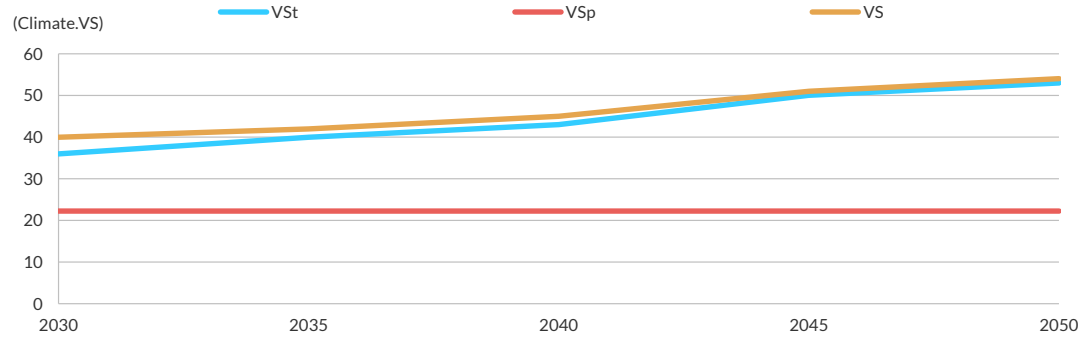
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Climate Vulnerability Considerations

Fitch uses Climate Vulnerability Signals (Climate.VS) as a screening tool to identify sectors and Fitch-rated issuers that are potentially most exposed to climate-related risks. If Fitch identifies an entity as higher risk (i.e. its Climate.VS in 2035 is 50 or higher), the entity receives additional analysis and consideration in rating reviews. Climate.VS range from 0 (lowest risk) to 100 (highest risk). For more information on Climate.VS, see Fitch's Corporate Rating Criteria. For more detailed, sector-specific information on how Fitch perceives climate-related transition risks, see Climate Vulnerability Signals for Non-Financial Corporate Sectors.

The Climate.VS for 2035 is 42 out of 100. This reflects a VSp of 22 and a VSt of 40.

Climate Vulnerability Signals

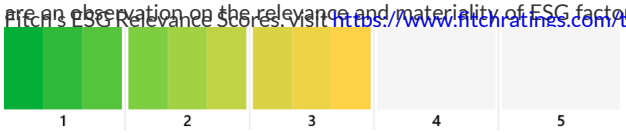


Source: Fitch Ratings

ESG Considerations

The highest level of ESG credit relevance is a score of '3', unless otherwise disclosed in this section. A score of '3' means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. Fitch's ESG Relevance Scores are not inputs in the rating process; they are an observation on the relevance and materiality of ESG factors in the rating decision. For more information on Fitch's ESG Relevance Scores, visit https://www.fitchratings.com/topics/esg/products#esg-relevance-scores.

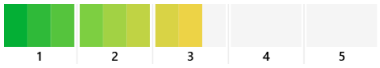
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Environmental Relevance Scores

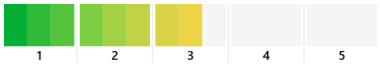
General issues	Score	Sector-specific issues	Reference
GHG Emissions & Air Quality	3	Emissions from operations	Company Operational Characteristics; Market and Competitive Positioning; Sector Characteristics; Profitability
Energy Management	3	Fuel use to generate energy and serve load	Company Operational Characteristics; Market and Competitive Positioning; Profitability
Water & Wastewater Management	2	Water used by hydro plants or by other generation plants, also effluent management	Company Operational Characteristics; Sector Characteristics; Profitability
Waste & Hazardous Materials Management; Ecological Impacts	3	Impact of waste from operations	Company Operational Characteristics; Sector Characteristics; Profitability
Exposure to Environmental Impacts	3	Plants' and networks' exposure to extreme weather	Company Operational Characteristics; Sector Characteristics; Profitability

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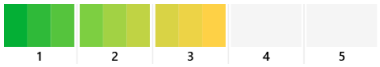
Social Relevance Scores

General issues	Score	Sector-specific issues	Reference
Human Rights, Community Relations, Access & Affordability	3	Product affordability and access	Company Operational Characteristics; Sector Characteristics; Profitability; Financial Structure
Customer Welfare - Fair Messaging, Privacy & Data Security	3	Quality and safety of products and services; data security	Sector Characteristics; Profitability
Labor Relations & Practices	3	Impact of labor negotiations and employee (dis)satisfaction	Company Operational Characteristics; Profitability
Employee Wellbeing	2	Worker safety and accident prevention	Profitability; Company Operational Characteristics
Exposure to Social Impacts	3	Social resistance to major projects that leads to delays and cost increases	Company Operational Characteristics; Profitability



Governance Relevance Scores

General issues	Score	Sector-specific issues	Reference
Management Strategy	3	Strategy development and implementation	Management; Governance
Governance Structure	3	Board independence and effectiveness; ownership concentration	Governance
Group Structure	3	Complexity, transparency and related-party transactions	Governance
Financial Transparency	3	Quality and timing of financial disclosure	Governance



ESG Scoring

ESG relevance scores range from '1' to '5' based on a 15-level colour gradation. Red (5) is most relevant to the credit rating and green (1) is least relevant.

The Environmental (E), Social (S) and Governance (G) tables break out the general and the sector-specific issues that are most relevant to each industry group. Relevance scores are assigned to each sector-specific issue, signalling the credit relevance of the sector-specific issues to an issuer's overall credit rating. The Reference column highlights the factor(s) within which the corresponding ESG issues are captured in Fitch's credit analysis.

The panels underneath the relevance scores tables are visualisations of the frequency of occurrence of the highest ESG relevance scores across the combined E, S and G categories. The Score columns summarise rating relevance and impact to credit from ESG issues. The column on the far left identifies any ESG relevance sub-factor issues that are drivers or potential drivers of an issuer's credit rating (corresponding with scores of '3', '4' or '5'). All scores of '4' and '5' are assumed to reflect a negative impact unless indicated with a '+' sign for positive impact.

Classification of ESG issues has been developed from Fitch's sector ratings criteria. The general and sector-specific issues draw on the classification standards published by the UN Principles for Responsible Investing, the Sustainability Accounting Standards Board and the World Bank.

Credit-Relevant ESG Scale

5 Highly relevant, a key rating driver that has a significant impact on the rating on an individual basis. Equivalent to 'Higher' relative importance within the Navigator.

4 Relevant to rating, not a key rating driver but has an impact on the rating in combination with other factors. Equivalent to 'Moderate' relative importance within the Navigator.

3 Minimally relevant to rating, either very low impact or actively managed in a way that results in no impact on the entity rating. Equivalent to 'Lower' relative importance within the Navigator.

2 Irrelevant to the entity rating but relevant to the sector.

1 Irrelevant to the entity rating and irrelevant to the sector.

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For information on the participation status in the rating process of an issuer listed in this report, please refer to the most recent rating action commentary for the relevant issuer, available on the Fitch Ratings website.

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Schedule E-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Service Area Calendar Sales by Major Customer Classes and System Output
5-Year Calendar Historical
(GWh)

Case No.: U-22070
Exhibit No.: A-5 (EMB-1)
Schedule: E-1
Page: 1 of 2
Witness: EMBreuring
Date: June 2026

Total Company Electric Deliveries

Line No.	Year		(a) Residential	(b) Commercial	(c) Industrial	(d) Other	(e) Total	(f) Losses & Company Use GWh	(g) Losses & Company Use % of Output	(h) System Output
1	2021	Hist	13,229	12,436	10,086	493	36,244	2,777	7.1%	39,021
2	2022	Hist	12,977	12,602	11,292	463	37,333	2,775	6.9%	40,108
3	2023	Hist	12,208	12,462	11,200	423	36,293	2,707	6.9%	39,000
4	2024	Hist	12,495	12,718	11,173	393	36,780	2,951	7.4%	39,731
5	2025	Hist	12,941	12,870	11,482	129	37,422	2,877	7.1%	40,299

Bundled Electric Deliveries

	Year		Residential	Commercial	Industrial	Other	Total	Losses & Company Use GWh	Losses & Company Use % of Output	System Output
6	2021	Hist	13,229	11,504	7,375	493	32,600	2,660	7.5%	35,260
7	2022	Hist	12,977	11,676	8,455	463	33,570	2,756	7.6%	36,326
8	2023	Hist	12,208	11,553	8,547	423	32,731	2,633	7.4%	35,365
9	2024	Hist	12,495	11,766	8,543	393	33,197	2,858	7.9%	36,055
10	2025	Hist	12,941	11,884	8,855	129	33,809	2,802	7.7%	36,611

Choice Electric Deliveries

	Year		Residential	Commercial	Industrial	Other	Total	Losses & Company Use GWh	Losses & Company Use % of Output	System Output
11	2021	Hist	-	932	2,712	-	3,644	116	3.1%	3,760
12	2022	Hist	-	926	2,837	-	3,763	20	0.5%	3,783
13	2023	Hist	-	909	2,653	-	3,562	74	2.0%	3,636
14	2024	Hist	-	953	2,630	-	3,583	93	2.5%	3,675
15	2025	Hist	-	987	2,627		3,614	75	2.0%	3,689

Schedule E-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Service Area Calendar Sales by Major Customer Classes
5-Year Calendar Historical - Weather-normalized
(GWh)

Case No.: U-22070
Exhibit No.: A-5 (EMB-1)
Schedule: E-1
Page: 2 of 2
Witness: EMBreuring
Date: June 2026

Total Company Electric Deliveries

Line No.		Year	(a) Residential	(b) Commercial	(c) Industrial	(d) Other	(e) Total
16	2021	Hist	12,747	12,258	10,059	492	35,557
17	2022	Hist	12,619	12,450	11,283	462	36,815
18	2023	Hist	12,597	12,560	11,211	423	36,791
19	2024	Hist	12,571	12,653	11,159	393	36,776
20	2025	Hist	12,564	12,704	11,481	129	36,878

Bundled Electric Deliveries

	Year		Residential	Commercial	Industrial	Other	Total
21	2021	Hist	12,747	11,338	7,350	492	31,927
22	2022	Hist	12,619	11,528	8,448	462	33,058
23	2023	Hist	12,597	11,657	8,553	423	33,231
24	2024	Hist	12,571	11,711	8,531	393	33,207
25	2025	Hist	12,564	11,732	8,852	129	33,277

Choice Electric Deliveries

	Year		Residential	Commercial	Industrial	Other	Total
26	2021	Hist	-	921	2,709	-	3,630
27	2022	Hist	-	922	2,835	-	3,757
28	2023	Hist	-	902	2,657	-	3,560
29	2024	Hist	-	942	2,627	-	3,569
30	2025	Hist	-	972	2,629	-	3,601

Schedule E-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Service Area Calendar Sales by Major Customer Classes and System Output
5-Year Projected
(GWh)

Case No.: U-22070
Exhibit No.: A-15 (EMB-2)
Schedule: E-1
Page: 1 of 1
Witness: EMBreuring
Date: June 2026

Total Company Electric Deliveries

Line No.	Year		(a) Residential	(b) Commercial	(c) Industrial	(d) Other	(e) Total	(f) Losses & Company Use GWh	(g) Losses & Company Use % of Output	(h) System Output
1	2026	Fcst	12,461	12,485	13,066	126	38,138	2,463	6.1%	40,601
2	2027	Fcst	12,505	12,479	13,433	121	38,537	2,442	6.0%	40,979
3	Test Year	Fcst	12,524	12,462	13,571	121	38,677	2,443	5.9%	41,121
4	2028	Fcst	12,613	12,503	13,830	120	39,066	2,436	5.9%	41,502
5	2029	Fcst	12,781	12,604	14,262	119	39,767	2,387	5.7%	42,154
6	2030	Fcst	12,977	12,671	15,912	119	41,679	2,453	5.6%	44,132

Bundled Electric Deliveries

	Year		Residential	Commercial	Industrial	Other	Total	Losses & Company Use GWh	Losses & Company Use % of Output	System Output
7	2026	Fcst	12,461	11,555	10,409	126	34,551	2,393	6.5%	36,944
8	2027	Fcst	12,505	11,546	10,773	121	34,945	2,373	6.4%	37,317
9	Test Year	Fcst	12,524	11,531	10,916	121	35,091	2,375	6.3%	37,466
10	2028	Fcst	12,613	11,571	11,165	120	35,469	2,369	6.3%	37,837
11	2029	Fcst	12,781	11,669	11,587	119	36,157	2,321	6.0%	38,479
12	2030	Fcst	12,977	11,730	13,227	119	38,053	2,433	6.0%	40,485

Choice Electric Deliveries

	Year		Residential	Commercial	Industrial	Other	Total	Losses & Company Use GWh	Losses & Company Use % of Output	System Output
13	2026	Fcst	-	930	2,657	-	3,587	69	1.9%	3,657
14	2027	Fcst	-	933	2,660	-	3,592	70	1.9%	3,662
15	Test Year	Fcst	-	931	2,655	-	3,586	68	1.9%	3,654
16	2028	Fcst	-	932	2,666	-	3,597	67	1.8%	3,665
17	2029	Fcst	-	935	2,676	-	3,610	65	1.8%	3,675
18	2030	Fcst	-	941	2,686	-	3,626	20	0.6%	3,646

Schedule E-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year Total Company Electric Revenues & Deliveries
May 2027 - April 2028

Case No.: U-22070
Exhibit No.: A-15 (EMB-3)
Schedule: E-2
Page: 1 of 1
Witness: EMBreuring
Date: June 2026

Line No.	Description	(a) 2025 Actual	(b) Less Non-Base Tariff Items: PSCR Factor	(c) Less Non-Base Tariff Items: Surcharges	(d) Less Non-Base Tariff Items: Other Adjustments	(e) LTILRR / LEDR	(f) Weather Normalization	(g) Change In Determinants	(h) Pro Forma	(i) Test Year: PSCR Factor	(j) Test Year: Total Company
	Adjusted Operating Revenues ($000)										
	Cycle Billed Tariff Revenue										
1	Base Tariff	$ 2,613,152	$ -	$ -	$ -	$ -	$ (36,909)	$ (427,026)	$ 700,307	$ -	$ 2,849,525
2	GSG Power Supply (1)	13,520	(13,520)	-	-	-	-	-	-	12,965	12,965
3	Base PSCR	2,016,991	-	-	-	-	(33,151)	(364,126)	179,903	-	1,799,617
4	PSCR Factor	303,772	(303,772)	-	-	-	-	-	-	408,717	408,717
5	Total Cycle Billed Tariff Revenue	4,947,435	(317,292)	-	-	-	(70,060)	(791,152)	880,210	421,682	5,070,824
	Cycle Billed Surcharge Revenue										
6	Energy Optimization	217,324	-	(217,296)	-	(28)	-	-	-	-	0
7	Renewables	19,335	-	(19,335)	-	-	-	-	-	-	-
8	LIEAF	22,606	-	(22,606)	-	(0)	-	-	-	-	(0)
9	Power Plant Securization Credit	-	-	-	-	-	-	-	-	-	-
10	Power Plant Securization Charge	35,607	-	(33,383)	-	(2,224)	-	-	-	-	(0)
11	Karn Securitization Credit	(18)		18		-	-	-	-	-	-
12	Karn Securitization Surcharge	126,143		(120,273)		(5,870)	-	-	-	-	(0)
13	Distribution Deferral Surcharge	20,219		(20,219)		-	-	-	-	-	-
14	DR Surcharge	35,654		(35,654)		-	-	-	-	-	-
15	IRM	5,095		(5,095)		-	-	-	-	-	-
16	Other Provisions for Refund	(222,266)	-	222,266	-	-	-	-	-	-	-
17	Total Cycle Billed Surcharge Revenue	259,699	-	(251,577)	-	(8,122)	-	-	-	-	(0)
18	Unbilled Revenue										
19	Base Tariff	(91,190)	-	-	91,069	122	-	-	-	-	0
20	Base PSCR	6,223	-	-	(6,223)	-	-	-	-	-	-
21	PSCR Factor	98,760	(98,760)	-	-	-	-	-	-	-	-
22	Total Unbilled Revenue	13,792	(98,760)	-	84,846	122	-	-	-	-	0
23	PSCR Over/Under Recovery	(78,484)	78,484	-	-	-	-	-	-	-	-
24	Total Calendar Revenue	5,142,443	(337,568)	(251,577)	84,846	(8,001)	(70,060)	(791,152)	880,210	421,682	5,070,824
25	Miscellaneous Revenue (2) (3) (4)	239,194	(808)	-	(201,431)	266,631	-	-	-	-	303,586.613
26	Intersystem Sales Revenue	140,466	-	-	(140,466)	-	-	-	$ 315,186	-	315,186
27	Total Operating Revenue	$ 5,522,103	$ (338,376)	$ (251,577)	$ (257,050)	$ 258,630	$ (70,060)	$ (791,152)	$ 1,195,396	$ 421,682	$ 5,689,597
28											
29	Revenue Adjustments										
30	Jobwork Revenue	1,859	-	-	-	-	-	-	-	-	1,858.745
31	Jobwork Expense	(1,256)	-	-	-	-	-	-	$ -	-	(1,256)
32	Total Revenue Adjustments	603	-	-	-	-	-	-	-	-	603
33											
34	Adjusted Total Operating Revenue	$ 5,522,706	$ (338,376)	$ (251,577)	$ (257,050)	$ 258,630	$ (70,060)	$ (791,152)	$ 1,195,396	$ 421,682	$ 5,690,200
35											
36	**Electric Deliveries (MWh)**										
37	Cycle Billed Bundled Service	33,604,808	-	-	-	2,722,467	(449,008)	(6,066,654)	-	-	29,811,613
38	Cycle Billed Self-generation	176,161	-	-	-	-	-	(22,967)	-	-	153,194
39	Cycle Billed Electric Choice	3,616,298	-	-	-	-	(6,242)	(21,616)	-	-	3,588,440
40	Intersystem Sales	4,515,404	-	-	(4,515,404)	-	-	-	-	-	-
41	Unbilled Bundled Service	27,691	-	-	(27,691)	41,216	-	(41,216)	-	-	-
42	Unbilled Electric Choice	(2,474)	-	-	2,474		-	-	-	-	-
43	Total Electric Deliveries	41,937,888	-	-	(4,540,621)	2,763,684	(455,250)	(6,152,453)	-	-	33,553,247

Notes:
(1) GSG Power Supply (ln2, col. i), (EMB-6)
(2) Miscellaneous Revenues (ln20, col. b): 2025 P-521, Page 301.1, Purchased Power Admin Fees
(3) Miscellaneous Revenues (ln20, col.d): Authorized Return on Renewable Energy Assets, FCM (2025 P-521, pg 301.1) removed; and LTILRR customer base tariff revenues (WP-2, ln 19 col. d); Grand Rapids Streetlighting; interest income; timber sales
(4) Miscellaneous Revenues (ln20, col. e): LTILRR (Michael Grondin) and LEDR (Michael Grondin)

Schedule E-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Deliveries & Customer Counts by Rate Category
(Annual Deliveries in MWh)

Case No.: U-22070
Exhibit No.: A-15 (EMB-4)
Schedule: E-3
Page: 1 of 1
Witness: EMBreuring
Date: June 2026

Line No.	Description	(a) 2025 Avg. No. of Customers	(b) 2025 Annual Deliveries	(c) Test Year Avg. No. of Customers	(d) Test Year Annual Deliveries
	Bundled Residential Service				
1	Standard Service RS	10,718	107,420	10,576	104,736
2	Peak Pwr Savers / Dynamic Pricing	-	-	-	-
3	Time-of-Day RT	-	-	-	-
4	Electric Vehicles REV-1	-	-	-	-
5	Electric Vehicles REV-2	-	-	-	-
6	Nighttime Savers (RPM)	11,026	139,424	17,382	178,119
7	Summer On-Peak (RSP)	1,612,034	12,507,628	1,620,743	12,029,020
8	Smart Hours (RSH)	28,963	217,005	29,526	201,637
9	Total Bundled Residential	1,662,741	12,971,477	1,678,227	12,513,512
	Bundled Secondary Service				
10	Secondary Energy-only GS	207,269	4,233,268	207,757	4,088,442
11	Secondary Demand GSD	19,291	2,914,557	19,819	2,854,081
12	Secondary GSTU	2,320	106,473	2,267	101,547
13	Total Bundled Secondary	228,880	7,254,298	229,843	7,044,071
	Bundled Primary Service				
14	Primary Energy-only GP	1,294	635,298	1,292	641,900
15	Primary Demand GPD	992	5,468,204	698	4,717,731
16	Primary Time-of-Use GPTU	1,519	3,936,915	1,696	4,345,527
17	General Service Primary (EIP)	19	407,653	15	390,752
18	Special Contract (Rate_LED)	-	-	-	-
19	Total Bundled Primary	3,824	10,448,070	3,701	10,095,910
	Bundled Street Lighting Service				
20	Unmetered Lighting GUL	3,755	48,489	-	-
21	Metered Lighting GML	384	4,334	386	10,465
22	Unmetered GU	458	94,905	460	92,721
23	Unmetered Lighting GU-LED	917	25,197	-	-
24	Universal Unmetered Lighting UUL			4,700	54,935
25	Total Bundled Street Lighting	5,514	172,925	5,547	158,121
	Bundled Self-generation Service				
26	Self-generation GSG-1	-	-	-	-
27	Self-generation GSG-2	22	176,161	14	153,194
28	Total Bundled Self-generation	22	176,161	14	153,194
	Bundled Other Service				
29	Wholesale	1	21,239	-	-
30	Grand Rapids	1	14,336	-	-
31	Total Bundled Other	2	35,575	-	-
32	Cycle Billed Bundled Service	1,900,983	31,058,505	1,917,333	29,964,807
33	Unbilled		27,691		-
34	Calendar Bundled Service	1,900,983	31,086,196	1,917,333	29,964,807
	ROA Secondary Service				
35	Secondary Energy-only GS	77	18,031	78	17,123
36	Secondary Demand GSD	460	176,941	474	167,933
37	Total ROA Secondary	537	194,972	552	185,056
	ROA Primary Service				
38	Primary Energy-only GP	58	74,361	46	70,709
39	Primary Demand GPD	370	3,346,965	375	3,332,675
40	Total ROA Primary	428	3,421,326	421	3,403,384
41	Cycle Billed ROA Service	965	3,616,298	973	3,588,440
42	Unbilled ROA		(2,474)		-
43	Calendar ROA Service	965	3,613,824	973	3,588,440
44	**Cycle Billed Total Deliveries**	1,901,948	34,674,803	1,918,306	33,553,247
45	**Unbilled**	-	25,217		-
46	**Calendar Total Deliveries**	1,901,948	34,700,020	1,918,306	33,553,247

Schedule E-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Annual System Load Factor
2021 - 2025 Historical / 2026 - 2030 Forecast

Case No.: U-22070
Exhibit No.: A-15 (EMB-5)
Schedule: E-4
Page: 1 of 1
Witness: EMBreuring
Date: June 2026

Line No.	Year		(a) System Output GWh	(b) System Peak Demand MW	(c) Annual Load Factor
1	2021	Hist	39,021	7,951	56.0%
2	2022	Hist	40,108	8,061	56.8%
3	2023	Hist	39,000	8,067	55.2%
4	2024	Hist	39,731	8,030	56.3%
5	2025	Hist	40,299	8,501	54.1%
6	2026	Fcst	40,601	7,433	62.4%
7	2027	Fcst	40,979	7,303	64.1%
8	Test Year	Fcst	41,121	7,303	64.3%
9	2028	Fcst	41,502	7,384	64.0%
10	2029	Fcst	42,154	7,529	63.9%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Estimated Electric Rate Case PSCR Factor
May 2027 - April 2028

Case No.: U-22070
Exhibit No.: A-45 (EMB-6)
Page: 1 of 1
Witness: EMBreuring
Date: June 2026

Line No.	Description	(a) Total Company
	Expenses ($000)	
1	System Power Supply Costs	$ 2,062,433
2	2025 Under-Recovery PSCR	$ -
3	Transmission & Market Administrative Expense	703,549
4	PSCR Expenses	$ 2,765,982
	PSCR Revenue Contributions ($000)	
5	Intersystem Sales Revenue	$ 315,186
6	Self-Generation	12,965
7	GI-2	-
8	Base Jurisdictional PSCR x base rate	1,799,617
9	Base Non-Jurisdictional PSCR	-
10	Long-Term Industrial Load Retention Rate/LED	229,367
11	Wholesale Fuel Revenue	-
12	PSCR Revenue Contributions	$ 2,357,136
13	PSCR (Over)/Under Recovery	$ 408,846
	Electric Deliveries (MWh)	
14	Jurisdictional Bundled Deliveries	32,821,802
15	Less: Self-Generation	(153,194)
16	Less: GI-2	-
17	Less: Long-Term Industrial Load Retention Rate	(2,856,995)
18	Total Bundled PSCR Deliveries	29,811,613
	Estimated Jurisdictional PSCR Factor	
19	PSCR (Over)/Under Recovery ($000)	$ 408,846
20	Total Bundled PSCR Deliveries (MWh)	29,811,613
21	Total Jurisdictional PSCR Factor ($ per kWh)	**$ 0.01371**
	Estimated PSCR Recovery	
22	PSCR Revenue Contributions	$ 2,357,136
23	Plus: PSCR (Over)/Under Recovery	408,717
24	Non-jurisdictional PSCR Factor Contribution	-
25	Total PSCR Revenues	$ 2,765,853
26	Total PSCR (Over)/Under Recovery	$ 129

Total Losses	0.0773
Less: Transmission	0.0000
System Losses	0.0773
System Efficiency	1.08378
PSCR Base @ Gen	0.05570
System Efficiency	1.08378
PSCR Base @ Del	**0.06037**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBIT

OF

ANN E. BULKLEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Constant Growth DCF			
Mean Results:			
30-Day Avg. Stock Price	9.24%	10.48%	11.56%
90-Day Avg. Stock Price	9.28%	10.52%	11.61%
180-Day Avg. Stock Price	9.49%	10.74%	11.82%
Average	9.34%	10.58%	11.66%
Median Results:			
30-Day Avg. Stock Price	9.44%	10.35%	11.20%
90-Day Avg. Stock Price	9.65%	10.55%	11.16%
180-Day Avg. Stock Price	9.73%	10.62%	11.51%
Average	9.61%	10.51%	11.29%

	30-Year Treasury Bond Yield	
	Current 30-Day Avg	Near-Term Projected
CAPM		
Current *Value Line* Beta	10.82%	10.88%
Long-term Avg. *Value Line* Beta	10.72%	10.78%
ECAPM		
Current *Value Line* Beta	11.29%	11.33%
Long-term Avg. *Value Line* Beta	11.22%	11.26%
Bond Yield Risk Premium	10.76%	10.89%

PROXY GROUP SCREENING DATA AND RESULTS

Company	Ticker	[1] Dividends	[2] S&P Credit Rating Between BBB- and AAA	[3] Positive Growth Rates from at least two sources (S&P Capital IQ, Value Line, and Zacks)	[4] Generation Assets Included in Rate Base	[5] Net Generation as a % of Total Sales > 30%	[6] Regulated Operating Income / Total Operating Income > 60%	[7] Announced Merger
Alliant Energy Corporation	LNT	Yes	BBB+	Yes	Yes	76.11%	97.51%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	71.06%	100.00%	No
American Electric Power Company, Inc.	AEP	Yes	BBB+	Yes	Yes	53.12%	95.39%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	60.63%	100.00%	No
Dominion Resources, Inc.	D	Yes	BBB+	Yes	Yes	77.34%	90.46%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	84.78%	85.04%	No
Duke Energy Corporation	DUK	Yes	BBB+	Yes	Yes	81.20%	89.73%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	72.59%	98.61%	No
Evergy, Inc.	EVRG	Yes	BBB+	Yes	Yes	59.95%	100.00%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	64.28%	99.99%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	96.46%	77.87%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	41.91%	97.73%	No
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Yes	Yes	69.56%	100.00%	No
PPL Corporation	PPL	Yes	A-	Yes	Yes	41.60%	100.00%	No
Southern Company	SO	Yes	A-	Yes	Yes	76.82%	96.29%	No
Xcel Energy Inc.	XEL	Yes	BBB+	Yes	Yes	58.19%	100.00%	No

Notes:
[1] Bloomberg Professional
[2] Bloomberg Professional
[3] S&P Capital IQ, Value Line Investment Survey, and Zacks
[4] S&P Capital IQ Pro
[5] S&P Capital IQ Pro
[6] Form 10-K's for 2025, 2024, and 2023
[7] S&P Capital IQ Pro Financial News Releases

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.14	$71.23	3.00%	3.11%	6.00%	7.48%	7.20%	6.89%	9.09%	10.00%	10.60%
Ameren Corporation	AEE	$3.00	$110.05	2.73%	2.83%	6.50%	7.77%	9.30%	7.86%	9.31%	10.69%	12.15%
American Electric Power Company, Inc.	AEP	$3.80	$131.04	2.90%	3.00%	6.50%	8.30%	6.70%	7.17%	9.49%	10.17%	11.32%
Avista Corporation	AVA	$1.97	$40.07	4.92%	5.08%	6.50%	6.19%	7.10%	6.60%	11.26%	11.68%	12.19%
Dominion Resources, Inc.	D	$2.67	$62.44	4.28%	4.45%	6.50%	7.01%	10.30%	7.94%	10.92%	12.38%	14.80%
DTE Energy Company	DTE	$4.66	$145.81	3.20%	3.30%	5.50%	7.02%	7.10%	6.54%	8.78%	9.84%	10.41%
Duke Energy Corporation	DUK	$4.26	$129.90	3.28%	3.38%	6.00%	6.57%	n/a	6.29%	9.38%	9.67%	9.96%
Entergy Corporation	ETR	$2.56	$105.15	2.43%	2.53%	3.00%	9.86%	11.50%	8.12%	5.47%	10.65%	14.07%
Evergy, Inc.	EVRG	$2.78	$81.52	3.41%	3.54%	6.50%	7.92%	9.10%	7.84%	10.02%	11.38%	12.67%
IDACORP, Inc.	IDA	$3.52	$141.27	2.49%	2.59%	6.00%	8.55%	8.00%	7.52%	8.57%	10.10%	11.15%
NextEra Energy, Inc.	NEE	$2.49	$91.99	2.71%	2.81%	8.00%	7.19%	n/a	7.60%	10.00%	10.41%	10.82%
OGE Energy Corporation	OGE	$1.70	$47.85	3.55%	3.64%	3.00%	6.49%	5.80%	5.10%	6.61%	8.74%	10.16%
Pinnacle West Capital Corporation	PNW	$3.64	$100.24	3.63%	3.74%	5.00%	7.48%	5.80%	6.09%	8.72%	9.84%	11.25%
PPL Corporation	PPL	$1.14	$37.76	3.02%	3.13%	7.50%	7.41%	7.30%	7.40%	10.43%	10.53%	10.63%
Southern Company	SO	$2.96	$96.11	3.08%	3.19%	6.50%	7.63%	7.20%	7.11%	9.68%	10.30%	10.82%
Xcel Energy Inc.	XEL	$2.37	$80.62	2.94%	3.06%	7.00%	8.70%	8.90%	8.20%	10.04%	11.26%	11.97%
Mean										9.24%	10.48%	11.56%
Median										9.44%	10.35%	11.20%

Notes:
[1] Bloomberg Professional as of March 31, 2026
[2] Bloomberg Professional 30-day average as of March 31, 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.14	$67.79	3.16%	3.27%	6.00%	7.48%	7.20%	6.89%	9.25%	10.16%	10.76%
Ameren Corporation	AEE	$3.00	$104.25	2.88%	2.99%	6.50%	7.77%	9.30%	7.86%	9.47%	10.85%	12.31%
American Electric Power Company, Inc.	AEP	$3.80	$122.06	3.11%	3.22%	6.50%	8.30%	6.70%	7.17%	9.71%	10.39%	11.54%
Avista Corporation	AVA	$1.97	$39.67	4.97%	5.13%	6.50%	6.19%	7.10%	6.60%	11.31%	11.73%	12.24%
Dominion Resources, Inc.	D	$2.67	$60.55	4.41%	4.58%	6.50%	7.01%	10.30%	7.94%	11.05%	12.52%	14.94%
DTE Energy Company	DTE	$4.66	$136.50	3.41%	3.53%	5.50%	7.02%	7.10%	6.54%	9.01%	10.07%	10.64%
Duke Energy Corporation	DUK	$4.26	$122.19	3.49%	3.60%	6.00%	6.57%	n/a	6.29%	9.59%	9.88%	10.18%
Entergy Corporation	ETR	$2.56	$97.95	2.61%	2.72%	3.00%	9.86%	11.50%	8.12%	5.65%	10.84%	14.26%
Evergy, Inc.	EVRG	$2.78	$76.92	3.61%	3.76%	6.50%	7.92%	9.10%	7.84%	10.23%	11.60%	12.88%
IDACORP, Inc.	IDA	$3.52	$133.49	2.64%	2.74%	6.00%	8.55%	8.00%	7.52%	8.72%	10.25%	11.30%
NextEra Energy, Inc.	NEE	$2.49	$86.30	2.89%	3.00%	8.00%	7.19%	n/a	7.60%	10.19%	10.60%	11.00%
OGE Energy Corporation	OGE	$1.70	$44.91	3.79%	3.88%	3.00%	6.49%	5.80%	5.10%	6.84%	8.98%	10.40%
OGE Energy Corporation	OGE	$1.69	$93.41	1.80%	1.86%	5.00%	7.48%	5.80%	6.09%	6.85%	7.95%	9.35%
PPL Corporation	PPL	$1.14	$35.99	3.17%	3.28%	7.50%	7.41%	7.30%	7.40%	10.58%	10.69%	10.79%
Southern Company	SO	$2.96	$90.37	3.28%	3.39%	6.50%	7.63%	7.20%	7.11%	9.88%	10.50%	11.03%
Xcel Energy Inc.	XEL	$2.37	$77.15	3.07%	3.20%	7.00%	8.70%	8.90%	8.20%	10.18%	11.40%	12.11%
Mean										9.28%	10.52%	11.61%
Median										9.65%	10.55%	11.16%

Notes:
[1] Bloomberg Professional as of March 31, 2026
[2] Bloomberg Professional 90-day average as of March 31, 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] S&P Capital IQ Projected EPS Growth Rate	[7] Zacks Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity: Minimum Growth Rate	[10] Cost of Equity: Mean Growth Rate	[11] Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.14	$66.41	3.22%	3.33%	6.00%	7.48%	7.20%	6.89%	9.32%	10.23%	10.83%
Ameren Corporation	AEE	$3.00	$102.19	2.94%	3.05%	6.50%	7.77%	9.30%	7.86%	9.53%	10.91%	12.37%
American Electric Power Company, Inc.	AEP	$3.80	$116.85	3.25%	3.37%	6.50%	8.30%	6.70%	7.17%	9.86%	10.54%	11.69%
Avista Corporation	AVA	$1.97	$38.19	5.16%	5.33%	6.50%	6.19%	7.10%	6.60%	11.51%	11.92%	12.44%
Dominion Resources, Inc.	D	$2.67	$59.57	4.48%	4.66%	6.50%	7.01%	10.30%	7.94%	11.13%	12.60%	15.01%
DTE Energy Company	DTE	$4.66	$136.05	3.43%	3.54%	5.50%	7.02%	7.10%	6.54%	9.02%	10.08%	10.65%
Duke Energy Corporation	DUK	$4.26	$121.57	3.50%	3.61%	6.00%	6.57%	n/a	6.29%	9.61%	9.90%	10.19%
Entergy Corporation	ETR	$2.56	$94.16	2.72%	2.83%	3.00%	9.86%	11.50%	8.12%	5.76%	10.95%	14.38%
Evergy, Inc.	EVRG	$2.78	$74.62	3.73%	3.87%	6.50%	7.92%	9.10%	7.84%	10.35%	11.71%	12.99%
IDACORP, Inc.	IDA	$3.52	$129.81	2.71%	2.81%	6.00%	8.55%	8.00%	7.52%	8.79%	10.33%	11.38%
NextEra Energy, Inc.	NEE	$2.49	$81.03	3.08%	3.19%	8.00%	7.19%	n/a	7.60%	10.38%	10.79%	11.20%
OGE Energy Corporation	OGE	$1.70	$44.64	3.81%	3.91%	3.00%	6.49%	5.80%	5.10%	6.87%	9.00%	10.42%
OGE Energy Corporation	OGE	$3.64	$90.88	4.01%	4.13%	5.00%	7.48%	5.80%	6.09%	9.11%	10.22%	11.64%
PPL Corporation	PPL	$1.14	$35.92	3.17%	3.29%	7.50%	7.41%	7.30%	7.40%	10.59%	10.70%	10.79%
Southern Company	SO	$2.96	$91.34	3.24%	3.36%	6.50%	7.63%	7.20%	7.11%	9.85%	10.46%	10.99%
Xcel Energy Inc.	XEL	$2.37	$75.91	3.12%	3.25%	7.00%	8.70%	8.90%	8.20%	10.23%	11.45%	12.16%
Mean										9.49%	10.74%	11.82%
Median										9.73%	10.62%	11.51%

Notes:
[1] Bloomberg Professional as of March 31, 2026
[2] Bloomberg Professional 180-day average as of March 31, 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Alliant Energy Corporation	LNT	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
Ameren Corporation	AEE	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
American Electric Power Company, Inc.	AEP	4.80%	0.70	12.70%	7.89%	10.33%	10.92%
Avista Corporation	AVA	4.80%	0.70	12.70%	7.89%	10.33%	10.92%
Dominion Resources, Inc.	D	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
DTE Energy Company	DTE	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
Duke Energy Corporation	DUK	4.80%	0.65	12.70%	7.89%	9.93%	10.62%
Entergy Corporation	ETR	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
Evergy, Inc.	EVRG	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
IDACORP, Inc.	IDA	4.80%	0.70	12.70%	7.89%	10.33%	10.92%
NextEra Energy, Inc.	NEE	4.80%	0.90	12.70%	7.89%	11.91%	12.10%
OGE Energy Corporation	OGE	4.80%	0.85	12.70%	7.89%	11.51%	11.81%
Pinnacle West Capital Corporation	PNW	4.80%	0.75	12.70%	7.89%	10.72%	11.22%
PPL Corporation	PPL	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
Southern Company	SO	4.80%	0.65	12.70%	7.89%	9.93%	10.62%
Xcel Energy Inc.	XEL	4.80%	0.70	12.70%	7.89%	10.33%	10.92%
Mean						10.82%	11.29%
Median						11.12%	11.51%

Notes:
[1] Bloomberg Professional 30-day average as of March 31, 2026
[2] Value Line
[3] Exhibit A-14 (AEB-1), Schedule D-5, p. 13
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (May 2026 - October 2027)	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] Cost of Equity: CAPM	[6] Cost of Equity: ECAPM
Alliant Energy Corporation	LNT	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
Ameren Corporation	AEE	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
American Electric Power Company, Inc.	AEP	5.03%	0.70	12.70%	7.67%	10.40%	10.97%
Avista Corporation	AVA	5.03%	0.70	12.70%	7.67%	10.40%	10.97%
Dominion Resources, Inc.	D	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
DTE Energy Company	DTE	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
Duke Energy Corporation	DUK	5.03%	0.65	12.70%	7.67%	10.01%	10.68%
Entergy Corporation	ETR	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
Evergy, Inc.	EVRG	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
IDACORP, Inc.	IDA	5.03%	0.70	12.70%	7.67%	10.40%	10.97%
NextEra Energy, Inc.	NEE	5.03%	0.90	12.70%	7.67%	11.93%	12.12%
OGE Energy Corporation	OGE	5.03%	0.85	12.70%	7.67%	11.55%	11.83%
Pinnacle West Capital Corporation	PNW	5.03%	0.75	12.70%	7.67%	10.78%	11.26%
PPL Corporation	PPL	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
Southern Company	SO	5.03%	0.65	12.70%	7.67%	10.01%	10.68%
Xcel Energy Inc.	XEL	5.03%	0.70	12.70%	7.67%	10.40%	10.97%
Mean						10.88%	11.33%
Median						11.16%	11.55%

Notes:
[1] Bloomberg Professional
[2] Value Line
[3] Exhibit A-14 (AEB-1), Schedule D-5, p. 13
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] Cost of Equity: CAPM	[6] Cost of Equity: ECAPM
Alliant Energy Corporation	LNT	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
Ameren Corporation	AEE	4.80%	0.75	12.70%	7.89%	10.72%	11.22%
American Electric Power Company, Inc.	AEP	4.80%	0.70	12.70%	7.89%	10.33%	10.92%
Avista Corporation	AVA	4.80%	0.70	12.70%	7.89%	10.33%	10.92%
Dominion Resources, Inc.	D	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
DTE Energy Company	DTE	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
Duke Energy Corporation	DUK	4.80%	0.65	12.70%	7.89%	9.93%	10.62%
Entergy Corporation	ETR	4.80%	0.75	12.70%	7.89%	10.72%	11.22%
Evergy, Inc.	EVRG	4.80%	0.75	12.70%	7.89%	10.72%	11.22%
IDACORP, Inc.	IDA	4.80%	0.65	12.70%	7.89%	9.93%	10.62%
NextEra Energy, Inc.	NEE	4.80%	0.90	12.70%	7.89%	11.91%	12.10%
OGE Energy Corporation	OGE	4.80%	0.85	12.70%	7.89%	11.51%	11.81%
Pinnacle West Capital Corporation	PNW	4.80%	0.75	12.70%	7.89%	10.72%	11.22%
PPL Corporation	PPL	4.80%	0.80	12.70%	7.89%	11.12%	11.51%
Southern Company	SO	4.80%	0.65	12.70%	7.89%	9.93%	10.62%
Xcel Energy Inc.	XEL	4.80%	0.70	12.70%	7.89%	10.33%	10.92%
Mean						10.72%	11.22%
Median						10.72%	11.22%

Notes:
[1] Bloomberg Professional 30-day average as of March 31, 2026
[2] Long-Term Beta
[3] Exhibit A-14 (AEB-1), Schedule D-5, p. 13
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (May 2026 - October 2027)	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] Cost of Equity: CAPM	[6] Cost of Equity: ECAPM
Alliant Energy Corporation	LNT	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
Ameren Corporation	AEE	5.03%	0.75	12.70%	7.67%	10.78%	11.26%
American Electric Power Company, Inc.	AEP	5.03%	0.70	12.70%	7.67%	10.40%	10.97%
Avista Corporation	AVA	5.03%	0.70	12.70%	7.67%	10.40%	10.97%
Dominion Resources, Inc.	D	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
DTE Energy Company	DTE	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
Duke Energy Corporation	DUK	5.03%	0.65	12.70%	7.67%	10.01%	10.68%
Entergy Corporation	ETR	5.03%	0.75	12.70%	7.67%	10.78%	11.26%
Evergy, Inc.	EVRG	5.03%	0.75	12.70%	7.67%	10.78%	11.26%
IDACORP, Inc.	IDA	5.03%	0.65	12.70%	7.67%	10.01%	10.68%
NextEra Energy, Inc.	NEE	5.03%	0.90	12.70%	7.67%	11.93%	12.12%
OGE Energy Corporation	OGE	5.03%	0.85	12.70%	7.67%	11.55%	11.83%
Pinnacle West Capital Corporation	PNW	5.03%	0.75	12.70%	7.67%	10.78%	11.26%
PPL Corporation	PPL	5.03%	0.80	12.70%	7.67%	11.16%	11.55%
Southern Company	SO	5.03%	0.65	12.70%	7.67%	10.01%	10.68%
Xcel Energy Inc.	XEL	5.03%	0.70	12.70%	7.67%	10.40%	10.97%
Mean						10.78%	11.26%
Median						10.78%	11.26%

Notes:
[1] Bloomberg Professional
[2] Long-Term Beta
[3] Exhibit A-14 (AEB-1), Schedule D-5, p. 13
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL VALUE LINE BETA

Company	Ticker	[1] 12/31/2013	[2] 12/31/2014	[3] 12/31/2015	[4] 12/31/2016	[5] 12/31/2017	[6] 12/31/2018	[7] 12/31/2019	[8] 12/31/2020	[9] 12/31/2021	[10] 12/31/2022	[11] 12/31/2023	[12] 12/31/2024	[13] 12/31/2025	[14] Average
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.85	0.90	0.90	0.80	0.78
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.85	0.90	0.90	0.75	0.75
American Electric Power Company, Inc.	AEP	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.75	0.80	0.80	0.70	0.70
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.90	0.90	0.95	0.70	0.80
Dominion Resources, Inc.	D	0.70	0.70	0.70	0.65	0.65	0.60	0.55	0.80	0.85	0.85	0.85	0.90	0.80	0.74
DTE Energy Company	DTE	0.80	0.75	0.75	0.65	0.65	0.55	0.55	0.95	0.95	0.95	0.95	1.00	0.80	0.79
Duke Energy Corporation	DUK	0.65	0.60	0.65	0.60	0.60	0.50	0.50	0.85	0.85	0.85	0.90	0.90	0.65	0.70
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.95	0.95	1.00	0.75	0.78
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.90	0.90	0.95	0.75	0.91
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0.80	0.80	0.85	0.85	0.65	0.74
NextEra Energy, Inc.	NEE	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.95	1.00	1.05	0.90	0.79
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	1.00	1.05	1.10	0.85	0.95
Pinnacle West Capital Corporation	PNW	0.75	0.70	0.75	0.70	0.70	0.55	0.50	0.90	0.90	0.90	0.95	0.95	0.75	0.77
PPL Corporation	PPL	0.65	0.60	0.70	0.70	0.75	0.70	0.70	1.15	1.10	1.05	1.10	1.10	0.80	0.85
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.90	0.95	0.95	0.65	0.70
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.80	0.85	0.85	0.70	0.69
Mean		0.72	0.71	0.74	0.67	0.68	0.59	0.57	0.91	0.90	0.89	0.93	0.95	0.75	0.78

Notes:

[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Value Line, Dated December 29, 2023.
[12] Value Line, Dated December 27, 2024.
[13] Value Line, Dated December 26, 2025.
[14] Average ([1] - [13])

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.45%
[2] Estimate of the S&P 500 Growth Rate	11.16%
[3] S&P 500 Estimated Required Market Return	12.70%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Avg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Agilent Technologies Inc	A	282.60232	113.98	32,211.01	0.07%	0.89%	0.00%	7.74%	0.01%
Apple Inc	AAPL	14681.14	253.79	3,725,926.52	8.59%	0.41%	0.04%	11.78%	1.01%
AbbVie Inc	ABBV	1768.76238	217.49	384,688.13	0.89%	3.18%	0.03%	15.59%	0.14%
Airbnb Inc	ABNB	423.57328	126.28	53,488.83	0.12%			19.81%	0.02%
Abbott Laboratories	ABT	1741.65732	102.67	178,815.96	0.41%	2.45%	0.01%	8.30%	0.03%
Arch Capital Group Ltd	ACGL	356.27284	95.99	34,198.63	0.08%			4.55%	0.00%
Accenture PLC	ACN	615.30676	198.29	122,009.18	0.28%	3.29%	0.01%	6.50%	0.02%
Adobe Inc	ADBE	404.2	243.08	98,252.94	0.23%			19.50%	0.04%
Analog Devices Inc	ADI	488.20416	318.14	155,317.27	0.36%	1.38%	0.00%	17.17%	0.06%
Archer-Daniels-Midland Co	ADM	481.87768	72.69	35,027.69	0.08%	2.86%	0.00%	10.21%	0.01%
Automatic Data Processing Inc	ADP	402.64436	203.18	81,809.28	0.19%	3.35%	0.01%	6.50%	0.01%
Autodesk Inc	ADSK	211	239.4	50,513.40	0.12%			16.07%	0.02%
Ameren Corp	AEE	276.42452	109.92	30,384.58	0.07%	2.73%	0.00%	7.89%	0.01%
American Electric Power Co Inc	AEP	543.56348	131.08	71,250.30	0.16%	2.90%	0.00%	6.85%	0.01%
AES Corp/The	AES	713.07162	14.09	10,047.18		5.00%		20.46%	
Aflac Inc	AFL	515.18367	109.71	56,520.80	0.13%	2.22%	0.00%	7.00%	0.01%
American International Group Inc	AIG	536.55966	75.25	40,376.11	0.09%	2.39%	0.00%	16.00%	0.01%
Assurant Inc	AIZ	49.69977	217.81	10,825.11	0.02%	1.62%	0.00%	9.50%	0.00%
Arthur J Gallagher & Co	AJG	256.88806	216.58	55,636.82		1.29%		25.00%	
Akamai Technologies Inc	AKAM	145.01397	114.85	16,654.85	0.04%			8.00%	0.00%
Albemarle Corp	ALB	117.65057	179.53	21,121.81	0.05%	0.90%	0.00%	5.50%	0.00%
Align Technology Inc	ALGN	71.61728	171.43	12,277.35	0.03%			4.53%	0.00%
Allstate Corp/The	ALL	259.53584	207.34	53,812.16	0.12%	2.08%	0.00%	10.65%	0.01%
Allegion plc	ALLE	86.14548	145.29	12,516.08	0.03%	1.51%	0.00%	5.89%	0.00%
Applied Materials Inc	AMAT	793.60987	341.79	271,247.92	0.63%	0.62%	0.00%	14.45%	0.09%
Amcor PLC	AMCR	462.04569	39.75	18,366.32	0.04%	6.54%	0.00%	8.72%	0.00%
Advanced Micro Devices Inc	AMD	1630.33878	203.43	331,659.82				35.83%	
AMETEK Inc	AME	229.06543	214.36	49,102.47	0.11%	0.63%	0.00%	8.79%	0.01%
Amgen Inc	AMGN	539.06768	351.85	189,670.96	0.44%	2.86%	0.01%	3.25%	0.01%
Ameriprise Financial Inc	AMP	90.68967	444.4	40,302.49	0.09%	1.44%	0.00%	10.41%	0.01%
American Tower Corp	AMT	466.08482	172.58	80,436.92	0.19%	4.15%	0.01%	7.50%	0.01%
Amazon.com Inc	AMZN	10734.92087	208.27	2,235,761.97				20.65%	
Arista Networks Inc	ANET	1256.53791	122.78	154,277.72	0.36%			15.47%	0.06%
Aon PLC	AON	214.2545	322.78	69,157.07	0.16%	0.92%	0.00%	11.50%	0.02%
A O Smith Corp	AOS	112.37665	65.94	7,410.12	0.02%	2.18%	0.00%	7.50%	0.00%
APA Corp	APA	353.25148	42.44	14,991.99		2.36%		-4.96%	
Air Products and Chemicals Inc	APD	222.65601	288.68	64,276.34	0.15%	2.51%	0.00%	5.68%	0.01%
Amphenol Corp	APH	1229.21493	126.35	155,311.31		0.79%		22.70%	
Apollo Global Management Inc	APO	578.24734	111.42	64,428.32	0.15%	1.83%	0.00%	19.83%	0.03%
AppLovin Corp	APP	307.07	398	122,213.86				50.08%	
Aptiv PLC	APTV	213.14133	58.8233	12,537.68	0.03%			18.32%	0.01%
Alexandria Real Estate Equities Inc	ARE	173.30036	46.42	8,044.60		6.20%		-5.91%	
Ares Management Corp	ARES	220.90261	109.1	24,100.47		4.95%		26.80%	
Atmos Energy Corp	ATO	165.43895	184.72	30,559.88	0.07%	2.17%	0.00%	8.51%	0.01%
AvalonBay Communities Inc	AVB	140.08347	163.35	22,882.63	0.05%	4.36%	0.00%	4.55%	0.00%
Broadcom Inc	AVGO	4734.66818	309.51	1,465,427.15		0.84%		37.46%	
Avery Dennison Corp	AVY	76.91703	172.68	13,282.03	0.03%	2.18%	0.00%	5.52%	0.00%
American Water Works Co Inc	AWK	195.28011	136.09	26,575.67	0.06%	2.43%	0.00%	7.00%	0.00%
Axon Enterprise Inc	AXON	80.39768	424.69	34,144.09				32.37%	
American Express Co	AXP	685.78347	301.5269	206,782.16	0.48%	1.26%	0.01%	12.58%	0.06%
AutoZone Inc	AZO	16.47682	3377.78	55,655.07	0.13%			8.86%	0.01%
Boeing Co/The	BA	785.84414	199.03	156,406.56					
Bank of America Corp	BAC	7145.70918	48.75	348,353.32	0.80%	2.30%	0.02%	9.00%	0.07%
Ball Corp	BALL	266.15306	59.11	15,732.31	0.04%	1.35%	0.00%	12.68%	0.00%
Baxter International Inc	BAX	516.25251	16.8	8,673.04		0.24%		-1.44%	
Best Buy Co Inc	BBY	209.11258	64.2	13,425.03	0.03%	5.98%	0.00%	3.23%	0.00%
Becton Dickinson & Co	BDX	284.74181	157.23	44,769.95	0.10%	2.67%	0.00%	4.30%	0.00%
Franklin Resources Inc	BEN	520.76345	23.62	12,300.43	0.03%	5.59%	0.00%	8.01%	0.00%
Brown-Forman Corp	BF/B	290.26239	26.44	7,674.54	0.02%	3.49%	0.00%	3.56%	0.00%
Bunge Global SA	BG	193.81041	127.2	24,652.68	0.06%	2.26%	0.00%	11.68%	0.01%
Biogen Inc	BIIB	146.75853	183.33	26,905.24	0.06%			2.88%	0.00%
Bank of New York Mellon Corp/The	BK	688.22698	118.63	81,644.37	0.19%	1.79%	0.00%	12.94%	0.02%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Avg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Booking Holdings Inc	BKNG	31.67335	4210.32	133,354.94	0.31%	1.00%	0.00%	15.45%	0.05%
Baker Hughes Co	BKR	991.75735	61.05	60,546.79	0.14%	1.51%	0.00%	16.79%	0.02%
Builders FirstSource Inc	BLDR	110.60507	82.33	9,106.12	0.02%			4.03%	0.00%
Blackrock Inc	BLK	155.54154	961.71	149,585.85	0.34%	2.38%	0.01%	13.07%	0.05%
Bristol-Myers Squibb Co	BMY	2041.73546	60.031	122,567.42		4.20%		26.00%	
Broadridge Financial Solutions Inc	BR	116.74872	162.48	18,969.33	0.04%	2.40%	0.00%	9.50%	0.00%
Berkshire Hathaway Inc	BRK/B	1390.7224	479.2	666,434.17	1.54%			9.50%	0.15%
Brown & Brown Inc	BRO	339.55919	65.21	22,142.65	0.05%	1.01%	0.00%	11.00%	0.01%
Boston Scientific Corp	BSX	1486.17517	62.75	93,257.49	0.22%			12.28%	0.03%
Blackstone Inc	BX	742.18074	114.99	85,343.36		5.18%		22.93%	
BXP Inc	BXP	158.62912	51.9	8,232.85	0.02%	5.39%	0.00%	0.68%	0.00%
Citigroup Inc	C	1749.31901	113.41	198,390.27	0.46%	2.12%	0.01%	19.61%	0.09%
Conagra Brands Inc	CAG	478.36948	15.72	7,519.97		8.91%		-5.35%	
Cardinal Health Inc	CAH	235.31602	210.7993	49,604.45	0.11%	0.97%	0.00%	13.87%	0.02%
Carrier Global Corp	CARR	835.43333	56.31	47,043.25	0.11%	1.70%	0.00%	10.20%	0.01%
Caterpillar Inc	CAT	465.28733	708.46	329,637.46	0.76%	0.85%	0.01%	16.91%	0.13%
Chubb Ltd	CB	390.22903	325.93	127,187.35	0.29%	1.19%	0.00%	6.56%	0.02%
Cboe Global Markets Inc	CBOE	104.6677	281.07	29,418.95	0.07%	1.02%	0.00%	13.38%	0.01%
CBRE Group Inc	CBRE	295.15855	135.46	39,982.18	0.09%			9.00%	0.01%
Crown Castle Inc	CCI	436.07044	81.31	35,456.89	0.08%	5.23%	0.00%	4.00%	0.00%
Carnival Corp	CCL	1239.00021	25.88	32,065.33	0.07%	2.32%	0.00%	10.90%	0.01%
Cadence Design Systems Inc	CDNS	276.09207	277.87	76,717.70	0.18%			13.31%	0.02%
CDW Corp/DE	CDW	128.70788	121.02	15,576.23	0.04%	2.08%	0.00%	6.88%	0.00%
Constellation Energy Corp	CEG	362.29467	279.25	101,170.79		0.61%		21.62%	
CF Industries Holdings Inc	CF	153.61643	129.84	19,945.56		1.54%		-14.50%	
Citizens Financial Group Inc	CFG	424.99389	59.97	25,486.88	0.06%	3.07%	0.00%	18.60%	0.01%
Church & Dwight Co Inc	CHD	236.87509	93.32	22,105.18	0.05%	1.32%	0.00%	7.11%	0.00%
CH Robinson Worldwide Inc	CHRW	117.85041	166.07	19,571.42	0.05%	1.52%	0.00%	14.37%	0.01%
Charter Communications Inc	CHTR	141.17837	215.88	30,477.59	0.07%			14.20%	0.01%
Cigna Group/The	CI	263.52828	266.75	70,296.17	0.16%	2.34%	0.00%	9.19%	0.01%
Ciena Corp	CIEN	141.39843	388.23	54,895.11				38.46%	
Cincinnati Financial Corp	CINF	155.6862	157.35	24,497.22	0.06%	2.39%	0.00%	9.50%	0.01%
Colgate-Palmolive Co	CL	802.30192	85.23	68,380.19	0.16%	2.49%	0.00%	7.77%	0.01%
Clorox Co/The	CLX	120.91186	103.63	12,530.10	0.03%	4.79%	0.00%	2.39%	0.00%
Comcast Corp	CMCSA	3588.40162	28.38	101,838.84	0.23%	4.65%	0.01%	0.95%	0.00%
CME Group Inc	CME	362.80494	295.35	107,154.44	0.25%	1.76%	0.00%	5.91%	0.01%
Chipotle Mexican Grill Inc	CMG	1302.423	32.01	41,690.56	0.10%			14.16%	0.01%
Cummins Inc	CMI	138.16546	538.02	74,335.78	0.17%	1.49%	0.00%	11.15%	0.02%
CMS Energy Corp	CMS	307.99665	77.58	23,894.38	0.06%	2.94%	0.00%	7.55%	0.00%
Centene Corp	CNC	491.77249	32.74	16,100.63				25.93%	
CenterPoint Energy Inc	CNP	652.87158	43.16	28,177.94	0.06%	2.13%	0.00%	8.10%	0.01%
Capital One Financial Corp	COF	621.92512	182.43	113,457.80	0.26%	1.75%	0.00%	11.89%	0.03%
Coherent Corp	COHR	187.48185	238.21	44,660.05				38.12%	
Coinbase Global Inc	COIN	223.04128	174.61	38,945.24				20.66%	
Cooper Cos Inc/The	COO	195.1144	71.5	13,950.68	0.03%			8.70%	0.00%
ConocoPhillips	COP	1220.80777	132	161,146.63		2.55%		-2.00%	
Cencora Inc	COR	194.53068	314.14	61,109.87	0.14%	0.76%	0.00%	8.46%	0.01%
Costco Wholesale Corp	COST	443.65254	996.43	442,068.70	1.02%	0.52%	0.01%	11.59%	0.12%
Corpay Inc	CPAY	68.0503	290.99	19,801.96	0.05%			12.94%	0.01%
Campbell's Company/The	CPB	298.14649	21.8819	6,524.01	0.02%	7.13%	0.00%	1.38%	0.00%
Copart Inc	CPRT	963.30839	33.2	31,981.84	0.07%			8.00%	0.01%
Camden Property Trust	CPT	104.727	97.66	10,227.64		4.34%		-1.66%	
CRH PLC	CRH	669.39985	105.12	70,367.31	0.16%	1.48%	0.00%	9.98%	0.02%
Charles River Laboratories International Inc	CRL	49.2278	172.5	8,491.80	0.02%			6.21%	0.00%
Salesforce Inc	CRM	923	186.67	172,296.41		0.94%		21.00%	
Crowdstrike Holdings Inc	CRWD	253.61409	390.41	99,013.48				30.00%	
Cisco Systems Inc	CSCO	3949.89304	77.1719	304,820.75	0.70%	2.18%	0.02%	7.40%	0.05%
CoStar Group Inc	CSGP	419.7933	40.34	16,934.46				32.12%	
CSX Corp	CSX	1859.99293	41.05	76,352.71	0.18%	1.36%	0.00%	11.25%	0.02%
Cintas Corp	CTAS	400.015	169.14	67,658.54	0.16%	1.06%	0.00%	12.18%	0.02%
Coterra Energy Inc	CTRA	759.35262	35.14	26,683.65	0.06%	2.50%	0.00%	3.00%	0.00%
Cognizant Technology Solutions Corp	CTSH	478.24692	61.35	29,340.45	0.07%	2.15%	0.00%	9.00%	0.01%
Corteva Inc	CTVA	671.3565	83.71	56,199.25	0.13%	0.86%	0.00%	10.40%	0.01%
Carvana Co	CVNA	142.99377	314.38	44,954.38					
CVS Health Corp	CVS	1272.21106	71.82	91,370.20	0.21%	3.70%	0.01%	7.13%	0.02%
Chevron Corp	CVX	1995.38554	206.9	412,845.27	0.95%	3.44%	0.03%	7.71%	0.07%
Dominion Energy Inc	D	878.96472	61.82	54,337.60	0.13%	4.32%	0.01%	6.15%	0.01%
Delta Air Lines Inc	DAL	653.13071	66.48	43,420.13	0.10%	1.13%	0.00%	11.83%	0.01%
DoorDash Inc	DASH	409.96686	150.15	61,556.52				39.94%	

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
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DuPont de Nemours Inc	DD	409.85427	45.8	18,771.33	0.04%	1.75%	0.00%	10.46%	0.00%
Datadog Inc	DDOG	328.48336	118.05	38,777.46	0.09%			19.94%	0.02%
Deere & Co	DE	270.10728	563.3	152,151.43	0.35%	1.15%	0.00%	9.67%	0.03%
Deckers Outdoor Corp	DECK	141.94997	100.09	14,207.77	0.03%			8.69%	0.00%
Dell Technologies Inc	DELL	318.35814	164.13	52,252.12	0.12%	1.54%	0.00%	15.59%	0.02%
Dollar General Corp	DG	220.22632	118.73	26,147.47	0.06%	1.99%	0.00%	4.16%	0.00%
Quest Diagnostics Inc	DGX	109.86632	195.98	21,531.60	0.05%	1.76%	0.00%	7.38%	0.00%
DR Horton Inc	DHI	289.7034	137.22	39,753.10	0.09%	1.31%	0.00%	4.98%	0.00%
Danaher Corp	DHR	707.69942	189.6	134,179.81	0.31%	0.84%	0.00%	6.16%	0.02%
Walt Disney Co/The	DIS	1771.51985	96.38	170,739.08	0.39%	1.56%	0.01%	14.91%	0.06%
Digital Realty Trust Inc	DLR	343.61544	180.21	61,922.94	0.14%	2.71%	0.00%	8.19%	0.01%
Dollar Tree Inc	DLTR	197.29822	109.51	21,606.13	0.05%			17.19%	0.01%
Healthpeak Properties Inc	DOC	695.25666	16.43	11,423.07	0.03%	7.43%	0.00%	3.54%	0.00%
Dover Corp	DOV	134.79645	208.45	28,098.32	0.06%	1.00%	0.00%	7.83%	0.01%
Dow Inc	DOW	705.76446	41.65	29,395.09		3.36%		35.25%	
Domino's Pizza Inc	DPZ	33.6257	358.79	12,064.56	0.03%	2.22%	0.00%	12.68%	0.00%
Darden Restaurants Inc	DRI	114.535	196.04	22,453.44	0.05%	3.06%	0.00%	10.31%	0.01%
DTE Energy Co	DTE	208.02812	146.22	30,417.87	0.07%	3.19%	0.00%	5.50%	0.00%
Duke Energy Corp	DUK	778.21667	130.94	101,899.69	0.23%	3.25%	0.01%	6.25%	0.01%
DaVita Inc	DVA	66.8	153.69	10,266.49	0.02%			18.16%	0.00%
Devon Energy Corp	DVN	621.4403	50.32	31,270.88	0.07%	1.91%	0.00%	4.61%	0.00%
Dexcom Inc	DXCM	384.86484	62.8	24,169.51	0.06%			18.94%	0.01%
Electronic Arts Inc	EA	250.25371	203.87	51,019.22	0.12%	0.37%	0.00%	11.50%	0.01%
eBay Inc	EBAY	448	91.02	40,776.96	0.09%	1.36%	0.00%	12.21%	0.01%
Ecolab Inc	ECL	282.42377	266.02	75,130.37	0.17%	1.10%	0.00%	10.47%	0.02%
Consolidated Edison Inc	ED	368.30269	113.18	41,684.50	0.10%	3.14%	0.00%	6.69%	0.01%
Equifax Inc	EFX	120.6346	180.07	21,722.67	0.05%	1.24%	0.00%	10.31%	0.01%
Everest Group Ltd	EG	40.39015	326.85	13,201.52	0.03%	2.45%	0.00%	6.00%	0.00%
Edison International	EIX	384.90595	73.18	28,167.42	0.06%	4.80%	0.00%	8.28%	0.01%
Estee Lauder Cos Inc/The	EL	247.2197	71.77	17,742.96		1.95%		24.32%	
Elevance Health Inc	ELV	232.62433	292.75	68,100.77	0.16%	2.35%	0.00%	3.77%	0.01%
EMCOR Group Inc	EME	44.53257	738.31	32,878.84	0.08%	0.22%	0.00%	16.50%	0.01%
Emerson Electric Co	EMR	562	131.02	73,633.24	0.17%	1.69%	0.00%	11.47%	0.02%
EOG Resources Inc	EOG	535.71581	144.57	77,448.43	0.18%	2.82%	0.01%	4.68%	0.01%
EPAM Systems Inc	EPAM	52.44431	135.4	7,100.96	0.02%			10.50%	0.00%
Equinix Inc	EQIX	98.25493	980.24	96,313.41	0.22%	2.11%	0.00%	15.00%	0.03%
Equity Residential	EQR	377.54711	59.15	22,331.91	0.05%	4.75%	0.00%	3.62%	0.00%
EQT Corp	EQT	624.274	63.64	39,728.80	0.09%	1.04%	0.00%	10.60%	0.01%
Erie Indemnity Co	ERIE	46.18907	251.31	11,607.78	0.03%	2.33%	0.00%	18.00%	0.00%
Eversource Energy	ES	375.84535	69.28	26,038.57	0.06%	4.55%	0.00%	4.26%	0.00%
Essex Property Trust Inc	ESS	64.47713	242	15,603.47	0.04%	4.28%	0.00%	4.25%	0.00%
Eaton Corp PLC	ETN	387.98534	357.67	138,770.72	0.32%	1.23%	0.00%	13.50%	0.04%
Entergy Corp	ETR	457.79863	112.36	51,438.25	0.12%	2.28%	0.00%	7.38%	0.01%
Evergy Inc	EVRG	229.74594	81.92	18,820.79	0.04%	3.39%	0.00%	7.79%	0.00%
Edwards Lifesciences Corp	EW	576.54169	80.08	46,169.46	0.11%			10.23%	0.01%
Exelon Corp	EXC	1023.17509	49.02	50,156.04	0.12%	3.43%	0.00%	6.00%	0.01%
Expand Energy Corp	EXE	240.39826	109.78	26,390.92		2.10%			
Expeditors International of Washington Inc	EXPD	132.98401	143.23	19,047.30	0.04%	1.08%	0.00%	4.99%	0.00%
Expedia Group Inc	EXPE	117.01142	230.89	27,016.77		0.83%		30.10%	
Extra Space Storage Inc	EXR	211.13767	131.13	27,686.48	0.06%	4.94%	0.00%	0.77%	0.00%
Ford Motor Co	F	3940.23019	11.54	45,470.26		5.20%		22.72%	
Diamondback Energy Inc	FANG	282.07899	197.79	55,792.40	0.13%	2.12%	0.00%	18.06%	0.02%
Fastenal Co	FAST	1148.32851	46.4	53,282.44	0.12%	2.07%	0.00%	9.74%	0.01%
Freeport-McMoRan Inc	FCX	1437.20161	58.78	84,478.71		1.02%		24.20%	
FactSet Research Systems Inc	FDS	37.09926	216.99	8,050.17	0.02%	2.03%	0.00%	5.43%	0.00%
FedEx Corp	FDX	238.60676	356.18	84,986.96	0.20%	1.63%	0.00%	9.63%	0.02%
FirstEnergy Corp	FE	577.12618	50.66	29,237.21	0.07%	3.67%	0.00%	6.17%	0.00%
F5 Inc	FFIV	56.51927	289.33	16,352.72	0.04%			5.71%	0.00%
Fair Isaac Corp	FICO	23.72213	1067.54	25,324.32				24.68%	
Fidelity National Information Services Inc	FIS	514.40369	46.91	24,130.68	0.06%	3.75%	0.00%	7.00%	0.00%
Fiserv Inc	FISV	534.77751	55.8	29,840.59	0.07%			6.50%	0.00%
Fifth Third Bancorp	FITB	905.5635	46.46	42,072.48	0.10%	3.44%	0.00%	10.00%	0.01%

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Comfort Systems USA Inc	FIX	35.17497	1378.99	48,505.93		0.20%		23.50%	
Fox Corp	FOX	224.70222	53.1	11,931.69	0.03%	1.05%	0.00%	1.78%	0.00%
Fox Corp	FOXA	200.69386	58.4	11,720.52	0.03%	0.96%	0.00%	4.89%	0.00%
Federal Realty Investment Trust	FRT	86.38821	105.08	9,077.67	0.02%	4.30%	0.00%	3.33%	0.00%
First Solar Inc	FSLR	107.31099	197.26	21,168.17				26.00%	
Fortinet Inc	FTNT	739.92358	81.72	60,466.55	0.14%			12.50%	0.02%
Fortive Corp	FTV	307.85919	55.28	17,018.46	0.04%	0.43%	0.00%	6.50%	0.00%
General Dynamics Corp	GD	270.84586	343.22	92,959.72	0.21%	1.85%	0.00%	11.26%	0.02%
GoDaddy Inc	GDDY	133.35412	82.67	11,024.39	0.03%			5.50%	0.00%
General Electric Co	GE	1044.8296	283.77	296,491.30	0.68%	0.66%	0.00%	17.09%	0.12%
GE HealthCare Technologies Inc	GEHC	456.29014	71.1454	32,462.94	0.07%	0.20%	0.00%	10.18%	0.01%
Gen Digital Inc	GEN	605.66377	18.83	11,404.65	0.03%	2.66%	0.00%	10.79%	0.00%
GE Vernova Inc	GEV	269.52946	872.9	235,272.27		0.23%		67.22%	
Gilead Sciences Inc	GILD	1241.20374	139.37	172,986.57	0.40%	2.35%	0.01%	11.16%	0.04%
General Mills Inc	GIS	533.68122	37.22	19,863.62		6.56%		-3.79%	
Globe Life Inc	GL	78.44455	138.843	10,891.48	0.03%	0.95%	0.00%	8.00%	0.00%
Corning Inc	GLW	859.01484	135.97	116,800.25		0.82%		29.54%	
General Motors Co	GM	903.96785	74.5	67,345.60	0.16%	0.97%	0.00%	11.83%	0.02%
Generac Holdings Inc	GNRC	58.67583	195.33	11,461.15	0.03%			18.50%	0.00%
Alphabet Inc	GOOG	5438	286.86	1,559,944.68	3.60%	0.29%	0.01%	14.06%	0.51%
Alphabet Inc	GOOGL	5822	287.56	1,674,174.32	3.86%	0.29%	0.01%	10.11%	0.39%
Genuine Parts Co	GPC	139.12211	105.75	14,712.16	0.03%	4.02%	0.00%	1.50%	0.00%
Global Payments Inc	GPN	275.24301	67.3	18,523.85	0.04%	1.49%	0.00%	7.00%	0.00%
Garmin Ltd	GRMN	192.48083	232.01	44,657.48	0.10%	1.81%	0.00%	8.19%	0.01%
Goldman Sachs Group Inc/The	GS	294.99394	845.99	249,561.92	0.58%	2.13%	0.01%	13.64%	0.08%
WW Grainger Inc	GWW	47.32999	1090.81	51,628.03	0.12%	0.83%	0.00%	6.88%	0.01%
Halliburton Co	HAL	837.54835	38.99	32,656.01	0.08%	1.74%	0.00%	7.21%	0.01%
Hasbro Inc	HAS	140.68576	93.6	13,168.19	0.03%	2.99%	0.00%	8.50%	0.00%
Huntington Bancshares Inc/OH	HBAN	2037.11966	15.65	31,880.92	0.07%	3.96%	0.00%	8.70%	0.01%
HCA Healthcare Inc	HCA	223.56897	473.24	105,801.78	0.24%	0.66%	0.00%	9.78%	0.02%
Home Depot Inc/The	HD	996.01147	328.89	327,578.21	0.76%	2.83%	0.02%	5.80%	0.04%
Hartford Insurance Group Inc/The	HIG	275.86322	135.23	37,304.98	0.09%	1.77%	0.00%	7.00%	0.01%
Huntington Ingalls Industries Inc	HII	39.37717	379.9	14,959.39	0.03%	1.45%	0.00%	15.28%	0.01%
Hilton Worldwide Holdings Inc	HLT	229.29162	304.08	69,723.00	0.16%	0.20%	0.00%	13.97%	0.02%
Hologic Inc	HOLX	223.24491	75.59	16,875.08	0.04%			5.50%	0.00%
Honeywell International Inc	HON	635.6757	226.03	143,681.78	0.33%	2.11%	0.01%	7.61%	0.03%
Robinhood Markets Inc	HOOD	790.05465	69.3	54,750.79				23.55%	
Hewlett Packard Enterprise Co	HPE	1326.85409	23.81	31,592.40	0.07%	2.39%	0.00%	12.68%	0.01%
HP Inc	HPQ	914.5502	19.21	17,568.51	0.04%	6.25%	0.00%	3.14%	0.00%
Hormel Foods Corp	HRL	550.28421	22.65	12,463.94	0.03%	5.17%	0.00%	5.81%	0.00%
Henry Schein Inc	HSIC	114.70412	73.7	8,453.69	0.02%			8.76%	0.00%
Host Hotels & Resorts Inc	HST	687.80218	19.16	13,178.29	0.03%	4.18%	0.00%	4.34%	0.00%
Hershey Co/The	HSY	148.07744	207.89	30,783.82	0.07%	2.79%	0.00%	11.75%	0.01%
Hubbell Inc	HUBB	53.02473	490.74	26,021.36	0.06%	1.16%	0.00%	7.50%	0.00%
Humana Inc	HUM	120.05446	173.39	20,816.24	0.05%	2.04%	0.00%	8.47%	0.00%
Howmet Aerospace Inc	HWM	400.94006	230.46	92,400.65		0.21%		20.50%	
Interactive Brokers Group Inc	IBKR	445.61648	67.07	29,887.50	0.07%	0.48%	0.00%	14.61%	0.01%
International Business Machines Corp	IBM	938.40907	242.39	227,460.97	0.52%	2.77%	0.01%	4.57%	0.02%
Intercontinental Exchange Inc	ICE	567.89651	157.28	89,318.76	0.21%	1.32%	0.00%	11.82%	0.02%
IDEXX Laboratories Inc	IDXX	79.51894	561.89	44,680.90	0.10%			11.91%	0.01%
IDEX Corp	IEX	74.20262	189.55	14,065.11	0.03%	1.50%	0.00%	4.50%	0.00%
International Flavors & Fragrances Inc	IFF	255.43782	72.55	18,532.01	0.04%	2.21%	0.00%	6.16%	0.00%
Incyte Corp	INCY	199.01449	94.12	18,731.24				21.75%	
Intel Corp	INTC	5021.01023	44.13	221,577.18				24.96%	
Intuit Inc	INTU	276.55	432.38	119,574.69	0.28%	1.11%	0.00%	13.50%	0.04%
Invitation Homes Inc	INVH	599.44602	24.85	14,896.23	0.03%	4.83%	0.00%	6.10%	0.00%
International Paper Co	IP	529.48621	35.7	18,902.66	0.04%	5.18%	0.00%	9.50%	0.00%
IQVIA Holdings Inc	IQV	169.7	170.54	28,940.64	0.07%			7.45%	0.00%
Ingersoll Rand Inc	IR	391.61799	80.12	31,376.43	0.07%	0.10%	0.00%	8.50%	0.01%
Iron Mountain Inc	IRM	297.47882	102.14	30,384.49	0.07%	3.38%	0.00%	9.50%	0.01%
Intuitive Surgical Inc	ISRG	354.98331	460.99	163,643.76	0.38%			14.44%	0.05%
Gartner Inc	IT	70.45029	158.34	11,155.10	0.03%			6.23%	0.00%
Illinois Tool Works Inc	ITW	288.07808	260.29	74,983.84	0.17%	2.47%	0.00%	8.92%	0.02%
Invesco Ltd	IVZ	443.32083	24.29	10,768.26		3.46%		24.23%	

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Avg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Jacobs Solutions Inc	J	117.44671	127.28	14,948.62	0.03%	1.13%	0.00%	10.29%	0.00%
JB Hunt Transport Services Inc	JBHT	94.60408	211.9	20,046.60	0.05%	0.85%	0.00%	11.60%	0.01%
Jabil Inc	JBL	105.59527	265.63	28,049.27	0.06%	0.12%	0.00%	15.78%	0.01%
Johnson Controls International plc	JCI	612.06621	130.95	80,150.07	0.18%	1.22%	0.00%	17.45%	0.03%
Jack Henry & Associates Inc	JKHY	72.16737	158.04	11,405.33	0.03%	1.54%	0.00%	11.00%	0.00%
Johnson & Johnson	JNJ	2408.61322	244.44	588,761.42	1.36%	2.13%	0.03%	7.25%	0.10%
JPMorgan Chase & Co	JPM	2697.03238	294.16	793,359.04	1.83%	2.04%	0.04%	10.31%	0.19%
Keurig Dr Pepper Inc	KDP	1358.66606	26.33	35,773.68	0.08%	3.49%	0.00%	10.97%	0.01%
KeyCorp	KEY	1072.69369	20.05	21,507.51	0.05%	4.09%	0.00%	13.11%	0.01%
Keysight Technologies Inc	KEYS	171.5025	282.37	48,427.16	0.11%			12.73%	0.01%
Kraft Heinz Co/The	KHC	1183.74475	22.49	26,622.42		7.11%		-0.76%	
Kimco Realty Corp	KIM	679.49863	22.47	15,268.33	0.04%	4.63%	0.00%	10.16%	0.00%
KKR & Co Inc	KKR	891.55089	92.5	82,468.46	0.19%	0.80%	0.00%	7.00%	0.01%
KLA Corp	KLAC	131.07661	1472.41	192,998.51	0.44%	0.52%	0.00%	13.25%	0.06%
Kimberly-Clark Corp	KMB	331.92577	96.47	32,020.88	0.07%	5.31%	0.00%	5.56%	0.00%
Kinder Morgan Inc	KMI	2224.8064	33.53	74,597.76	0.17%	3.49%	0.01%	7.92%	0.01%
Coca-Cola Co/The	KO	4304.15288	76.05	327,330.83	0.75%	2.79%	0.02%	7.12%	0.05%
Kroger Co/The	KR	612.57561	72.36	44,325.97	0.10%	1.93%	0.00%	6.00%	0.01%
Kenvue Inc	KVUE	1916.73209	17.24	33,044.46	0.08%	4.81%	0.00%	13.12%	0.01%
Loews Corp	L	206.05287	106.74	21,994.08	0.05%	0.23%	0.00%	15.50%	0.01%
Leidos Holdings Inc	LDOS	125.92855	155.52	19,584.41	0.05%	1.11%	0.00%	11.00%	0.00%
Lennar Corp	LEN	216.50828	86.84	18,801.58	0.04%	2.30%	0.00%	2.46%	0.00%
Labcorp Holdings Inc	LH	82.4	266.81	21,985.14	0.05%	1.08%	0.00%	6.37%	0.00%
L3Harris Technologies Inc	LHX	186.77626	345.15	64,465.83	0.15%	1.45%	0.00%	13.86%	0.02%
Lennox International Inc	LII	34.80291	464.13	16,153.07	0.04%	1.12%	0.00%	11.00%	0.00%
Linde PLC	LIN	463.39416	495.76	229,732.29	0.53%	1.29%	0.01%	8.03%	0.04%
Lumentum Holdings Inc	LITE	71.4	702.76	50,177.06					
Eli Lilly & Co	LLY	944.81888	919.77	869,016.06	2.00%	0.75%	0.02%	20.00%	0.40%
Lockheed Martin Corp	LMT	230.46212	604.39	139,289.00	0.32%	2.28%	0.01%	16.44%	0.05%
Alliant Energy Corp	LNT	258.27648	71.76	18,533.92	0.04%	2.98%	0.00%	6.20%	0.00%
Lowe's Cos Inc	LOW	560.06343	236.28	132,331.79	0.31%	2.03%	0.01%	4.58%	0.01%
Lam Research Corp	LRCX	1248.771	213.66	266,812.41	0.62%	0.49%	0.00%	19.59%	0.12%
Lululemon Athletica Inc	LULU	110.48267	153.1	16,914.90	0.04%			4.00%	0.00%
Southwest Airlines Co	LUV	491.07575	37.57	18,449.72		1.92%		49.98%	
Las Vegas Sands Corp	LVS	671.91072	53.88	36,202.55		2.23%		20.11%	
LyondellBasell Industries NV	LYB	322.16998	80.56	25,954.01	0.06%	3.43%	0.00%	18.53%	0.01%
Live Nation Entertainment Inc	LYV	234.80192	152.51	35,809.64				149.55%	
Mastercard Inc	MA	885.21639	499.66	442,307.22	1.02%	0.70%	0.01%	13.35%	0.14%
Mid-America Apartment Communities Inc	MAA	116.90102	122.12	14,275.95	0.03%	5.01%	0.00%	1.09%	0.00%
Marriott International Inc/MD	MAR	264.93199	327.07	86,651.31	0.20%	0.82%	0.00%	9.00%	0.02%
Masco Corp	MAS	203.60709	60.37	12,291.76	0.03%	2.12%	0.00%	7.61%	0.00%
McDonald's Corp	MCD	710.39864	310.79	220,784.79	0.51%	2.39%	0.01%	9.03%	0.05%
Microchip Technology Inc	MCHP	541.13546	64.61	34,962.76	0.08%	2.82%	0.00%	19.73%	0.02%
McKesson Corp	MCK	122.48746	865.36	105,995.75	0.24%	0.38%	0.00%	13.28%	0.03%
Moody's Corp	MCO	178.00388	436.25	77,654.19	0.18%	0.94%	0.00%	11.08%	0.02%
Mondelez International Inc	MDLZ	1281.84567	57.64	73,885.58	0.17%	3.47%	0.01%	7.61%	0.01%
Medtronic PLC	MDT	1283.88496	86.65	111,248.63	0.26%	3.28%	0.01%	7.02%	0.02%
MetLife Inc	MET	652.05387	70.72	46,113.25	0.11%	3.21%	0.00%	10.29%	0.01%
Meta Platforms Inc	META	2187.17775	572.13	1,251,350.01	2.89%	0.37%	0.01%	18.04%	0.52%
MGM Resorts International	MGM	255.84664	37.01	9,468.88				25.00%	
McCormick & Co Inc/MD	MKC	253.59054	50.44	12,791.11	0.03%	3.81%	0.00%	5.64%	0.00%
Martin Marietta Materials Inc	MLM	60.31205	588.68	35,504.50	0.08%	0.56%	0.00%	9.00%	0.01%
3M Co	MMM	522.39618	145.23	75,867.60		2.15%		30.85%	
Monster Beverage Corp	MNST	977.90602	72.46	70,859.07	0.16%			12.29%	0.02%
Altria Group Inc	MO	1671.89809	65.99	110,328.55	0.25%	6.43%	0.02%	4.41%	0.01%
Mosaic Co/The	MOS	317.50526	25.5	8,096.38	0.02%	3.45%	0.00%	5.94%	0.00%
Marathon Petroleum Corp	MPC	294.49688	244.18	71,910.25	0.17%	1.64%	0.00%	11.01%	0.02%
Monolithic Power Systems Inc	MPWR	49.118	1093.35	53,703.17	0.12%	0.73%	0.00%	15.00%	0.02%
Merck & Co Inc	MRK	2472.392	120.29	297,404.03	0.69%	2.83%	0.02%	12.50%	0.09%
Moderna Inc	MRNA	396.58686	50.8	20,146.61				24.62%	
Marsh & McLennan Cos Inc	MRSH	484.12425	173.45	83,971.35	0.19%	2.08%	0.00%	14.00%	0.03%
Morgan Stanley	MS	1587.86021	164.57	261,314.15	0.60%	2.43%	0.01%	11.46%	0.07%
MSCI Inc	MSCI	73.12021	539.01	39,412.52	0.09%	1.52%	0.00%	10.95%	0.01%
Microsoft Corp	MSFT	7425.62908	370.17	2,748,745.12	6.34%	0.98%	0.06%	15.65%	0.99%
Motorola Solutions Inc	MSI	165.65891	433.97	71,891.00	0.17%	1.12%	0.00%	9.15%	0.02%
M&T Bank Corp	MTB	149.00025	206.72	30,801.33	0.07%	2.90%	0.00%	9.24%	0.01%
Mettler-Toledo International Inc	MTD	20.24851	1261.2	25,537.42	0.06%			8.88%	0.01%
Micron Technology Inc	MU	1127.73405	337.84	380,993.67		0.18%		101.94%	
Norwegian Cruise Line Holdings Ltd	NCLH	455.54564	18.7	8,518.70	0.02%			15.13%	0.00%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Avg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Nasdaq Inc	NDAQ	568.44386	84.89	48,255.20	0.11%	1.27%	0.00%	12.85%	0.01%
Nordson Corp	NDSN	55.7836	266.06	14,841.78	0.03%	1.23%	0.00%	8.00%	0.00%
NextEra Energy Inc	NEE	2083.52196	92.88	193,517.52	0.45%	2.68%	0.01%	7.85%	0.04%
Newmont Corp	NEM	1079.93313	108.25	116,902.76	0.27%	0.96%	0.00%	10.59%	0.03%
Netflix Inc	NFLX	4222.16215	96.15	405,960.89				22.52%	
NiSource Inc	NI	479.35779	46.66	22,366.83	0.05%	2.57%	0.00%	7.50%	0.00%
NIKE Inc	NKE	1191.49565	52.82	62,934.80	0.15%	3.10%	0.00%	8.61%	0.01%
Northrop Grumman Corp	NOC	141.92162	682.24	96,824.61	0.22%	1.35%	0.00%	7.60%	0.02%
ServiceNow Inc	NOW	1046	104.55	109,359.30				25.50%	
NRG Energy Inc	NRG	214.55659	146.14	31,355.30	0.07%	1.30%	0.00%	20.00%	0.01%
Norfolk Southern Corp	NSC	224.50483	287	64,432.89	0.15%	1.88%	0.00%	8.50%	0.01%
NetApp Inc	NTAP	197.3304	101.8682	20,101.69	0.05%	2.04%	0.00%	6.99%	0.00%
Northern Trust Corp	NTRS	185.32092	139.57	25,865.24	0.06%	2.29%	0.00%	8.50%	0.01%
Nucor Corp	NUE	227.63611	169.1	38,493.27	0.09%	1.32%	0.00%	16.59%	0.01%
NVIDIA Corp	NVDA	24300	174.4	4,237,920.00		0.02%		35.78%	
NVR Inc	NVR	2.77812	6589.83	18,307.34	0.04%			4.52%	0.00%
News Corp	NWS	184.3403	28.51	5,255.54		0.70%			
News Corp	NWSA	367.8178	24.93	9,169.70		0.80%		23.50%	
NXP Semiconductors NV	NXPI	252.69285	196.86	49,745.11	0.11%	2.06%	0.00%	11.05%	0.01%
Realty Income Corp	O	932.45063	61.18	57,047.33	0.13%	5.31%	0.01%	3.98%	0.01%
Old Dominion Freight Line Inc	ODFL	208.42562	195.4	40,726.37	0.09%	0.59%	0.00%	9.96%	0.01%
ONEOK Inc	OKE	629.78363	90.39	56,926.14	0.13%	4.74%	0.01%	12.50%	0.02%
Omnicom Group Inc	OMC	284.98898	75.31	21,462.52	0.05%	4.25%	0.00%	9.47%	0.00%
ON Semiconductor Corp	ON	394.02053	61.92	24,397.75	0.06%			13.32%	0.01%
Oracle Corp	ORCL	2876.046	147.11	423,095.13		1.36%		21.11%	
O'Reilly Automotive Inc	ORLY	836.69947	92.31	77,235.73	0.18%			10.24%	0.02%
Otis Worldwide Corp	OTIS	388.72077	77.08	29,962.60	0.07%	2.18%	0.00%	9.50%	0.01%
Occidental Petroleum Corp	OXY	991.69518	65	64,460.19		1.60%			
Palo Alto Networks Inc	PANW	816	160.32	130,821.12				26.50%	
Paychex Inc	PAYX	358.29088	92.12	33,005.76	0.08%	4.69%	0.00%	7.50%	0.01%
PACCAR Inc	PCAR	526.26297	115.5	60,783.37	0.14%	1.14%	0.00%	10.28%	0.01%
PG&E Corp	PCG	2197.96795	17.57	38,618.30	0.09%	1.14%	0.00%	9.50%	0.01%
Public Service Enterprise Group Inc	PEG	498.73991	80.95	40,373.00	0.09%	3.31%	0.00%	7.70%	0.01%
PepsiCo Inc	PEP	1366.94097	155.29	212,272.26	0.49%	3.66%	0.02%	5.67%	0.03%
Pfizer Inc	PFE	5688.35613	28.08	159,729.04	0.37%	6.13%	0.02%	9.00%	0.03%
Principal Financial Group Inc	PFG	216.83514	90.11	19,539.01	0.05%	3.55%	0.00%	7.75%	0.00%
Procter & Gamble Co/The	PG	2324.00069	144.44	335,678.66	0.77%	2.93%	0.02%	4.49%	0.03%
Progressive Corp/The	PGR	584.96282	198.1375	115,903.07	0.27%	0.20%	0.00%	8.06%	0.02%
Parker-Hannifin Corp	PH	126.21653	895.24	112,994.09	0.26%	0.80%	0.00%	10.01%	0.03%
PulteGroup Inc	PHM	191.58925	117.61	22,532.81	0.05%	0.88%	0.00%	4.48%	0.00%
Packaging Corp of America	PKG	89.02795	212.22	18,893.51	0.04%	2.36%	0.00%	9.06%	0.00%
Prologis Inc	PLD	932.23068	132.18	123,222.25	0.28%	3.24%	0.01%	5.46%	0.02%
Palantir Technologies Inc	PLTR	2291.47075	146.28	335,196.34				47.57%	
Philip Morris International Inc	PM	1558.53027	165.34	257,687.39	0.59%	3.56%	0.02%	7.62%	0.05%
PNC Financial Services Group Inc/The	PNC	403.37092	208.09	83,937.45	0.19%	3.27%	0.01%	11.53%	0.02%
Pentair PLC	PNR	161.6028	87.11	14,077.22	0.03%	1.24%	0.00%	14.00%	0.00%
Pinnacle West Capital Corp	PNW	120.90539	100.75	12,181.22	0.03%	3.61%	0.00%	6.06%	0.00%
Insulet Corp	PODD	70.39585	209.84	14,771.87				28.35%	
Pool Corp	POOL	36.70058	202.33	7,425.63	0.02%	2.47%	0.00%	4.12%	0.00%
PPG Industries Inc	PPG	223.79865	106.88	23,919.60	0.06%	2.66%	0.00%	6.88%	0.00%
PPL Corp	PPL	751.307	38.2	28,699.93	0.07%	2.98%	0.00%	7.50%	0.00%
Prudential Financial Inc	PRU	347.8187	97.69	33,978.41	0.08%	5.73%	0.00%	7.00%	0.01%
Public Storage	PSA	175.54216	270.88	47,550.86	0.11%	4.43%	0.00%	4.96%	0.01%
Paramount Skydance Corp	PSKY	1080.24102	9.02	9,743.77		2.22%		25.16%	
Phillips 66	PSX	400.74402	182.18	73,007.55		2.79%		42.52%	
PTC Inc	PTC	118.99612	142.49	16,955.76	0.04%			10.00%	0.00%
Quanta Services Inc	PWR	149.61943	548.9124	82,127.96	0.19%	0.08%	0.00%	17.11%	0.03%
PayPal Holdings Inc	PYPL	920.66454	45.23	41,641.66	0.10%	1.24%	0.00%	8.16%	0.01%
Qnity Electronics Inc	Q	209.65891	115.38	24,190.45		0.28%			
QUALCOMM Inc	QCOM	1067	128.78	137,408.26	0.32%	2.86%	0.01%	3.19%	0.01%
Royal Caribbean Cruises Ltd	RCL	270.5283	275.18	74,443.98	0.17%	2.18%	0.00%	13.63%	0.02%
Regency Centers Corp	REG	183.08337	75.66	13,852.09	0.03%	3.99%	0.00%	5.65%	0.00%
Regeneron Pharmaceuticals Inc	REGN	103.90266	772.64	80,279.35	0.19%	0.49%	0.00%	9.50%	0.02%
Regions Financial Corp	RF	854.31627	26.12	22,314.74	0.05%	4.06%	0.00%	8.40%	0.00%
Raymond James Financial Inc	RJF	197.09104	144.2499	28,430.36	0.07%	1.50%	0.00%	12.84%	0.01%
Ralph Lauren Corp	RL	38.65514	343.99	13,296.98	0.03%	1.06%	0.00%	17.07%	0.01%
ResMed Inc	RMD	145.6784	224.48	32,701.89	0.08%	1.07%	0.00%	10.22%	0.01%
Rockwell Automation Inc	ROK	112.35791	358.88	40,323.01	0.09%	1.54%	0.00%	12.23%	0.01%
Rollins Inc	ROL	481.98884	53.41	25,743.02	0.06%	1.37%	0.00%	11.55%	0.01%
Roper Technologies Inc	ROP	102.92752	353.86	36,421.93	0.08%	1.03%	0.00%	8.00%	0.01%
Ross Stores Inc	ROST	322.35679	216.63	69,832.15	0.16%	0.82%	0.00%	8.59%	0.01%
Republic Services Inc	RSG	308.95619	218.3995	67,475.88	0.16%	1.14%	0.00%	8.25%	0.01%
RTX Corp	RTX	1345.97422	192.9	259,638.43	0.60%	1.41%	0.01%	11.06%	0.07%
Revvity Inc	RVTY	111.80333	87.61	9,795.09	0.02%	0.32%	0.00%	6.86%	0.00%
EchoStar Corp	SATS	157.52739	117.07	18,441.73					
SBA Communications Corp	SBAC	105.78859	172.11	18,207.27	0.04%	2.91%	0.00%	3.27%	0.00%
Starbucks Corp	SBUX	1139.3	89.59	102,069.89	0.24%	2.77%	0.01%	8.80%	0.02%
Charles Schwab Corp/The	SCHW	1738.09944	93.98	163,346.59	0.38%	1.36%	0.01%	13.61%	0.05%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Avg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Sherwin-Williams Co/The	SHW	247.36235	320.55	79,292.00	0.18%	1.00%	0.00%	10.48%	0.02%
J M Smucker Co/The	SJM	106.64832	96.44	10,285.16	0.02%	4.56%	0.00%	3.51%	0.00%
SLB Ltd	SLB	1501.1333	51.39	77,143.24	0.18%	2.30%	0.00%	7.22%	0.01%
Super Micro Computer Inc	SMCI	600.48195	22.77	13,672.97				27.06%	
Snap-on Inc	SNA	52.05734	363.22	18,908.27	0.04%	2.69%	0.00%	4.55%	0.00%
Sandisk Corp/DE	SNDK	153.38838	635.34	97,453.77					
Synopsys Inc	SNPS	191.56203	396.48	75,950.51	0.18%			13.23%	0.02%
Southern Co/The	SO	1119.39129	96.52	108,043.65	0.25%	3.07%	0.01%	6.80%	0.02%
Solventum Corp	SOLV	173.40525	65.3	11,323.36	0.03%			9.40%	0.00%
Simon Property Group Inc	SPG	324.94527	186.53	60,612.04	0.14%	4.72%	0.01%	3.50%	0.00%
S&P Global Inc	SPGI	306	425.34	130,154.04	0.30%	0.91%	0.00%	10.39%	0.03%
Sempra	SRE	653.33256	97.17	63,484.32	0.15%	2.71%	0.00%	5.00%	0.01%
STERIS PLC	STE	98.07503	221.13	21,687.33	0.05%	1.14%	0.00%	8.00%	0.00%
Steel Dynamics Inc	STLD	144.72223	180	26,050.00	0.06%	1.18%	0.00%	13.91%	0.01%
State Street Corp	STT	278.72821	125.72	35,041.71	0.08%	2.67%	0.00%	10.43%	0.01%
Seagate Technology Holdings PLC	STX	218.07307	391.76	85,432.31		0.76%		37.27%	
Constellation Brands Inc	STZ	173.38463	150	26,007.69	0.06%	2.72%	0.00%	0.83%	0.00%
Smurfit Westrock PLC	SW	524.25374	39.85	20,891.51		4.54%			
Stanley Black & Decker Inc	SWK	155.28643	71.06	11,034.65	0.03%	4.67%	0.00%	20.00%	0.01%
Skyworks Solutions Inc	SWKS	150.40596	53.55	8,054.24		5.30%		-4.65%	
Synchrony Financial	SYF	347.59628	68.02	23,643.50	0.05%	1.76%	0.00%	8.66%	0.00%
Stryker Corp	SYK	382.98425	328.59	125,844.79	0.29%	1.07%	0.00%	10.05%	0.03%
Sysco Corp	SYY	478.93065	70.7963	33,906.52	0.08%	3.05%	0.00%	7.00%	0.01%
AT&T Inc	T	6983.55628	28.99	202,453.30	0.47%	3.83%	0.02%	7.56%	0.04%
Molson Coors Beverage Co	TAP	175.63934	43.06	7,563.03	0.02%	4.46%	0.00%	2.82%	0.00%
TransDigm Group Inc	TDG	56.47356	1158.96	65,450.60	0.15%			13.09%	0.02%
Teledyne Technologies Inc	TDY	46.31729	605.01	28,022.42	0.06%			9.24%	0.01%
Bio-Techne Corp	TECH	156.45329	52.26	8,176.25	0.02%	0.61%	0.00%	13.00%	0.00%
TE Connectivity PLC	TEL	293.43427	209.02	61,333.63	0.14%	1.49%	0.00%	11.20%	0.02%
Teradyne Inc	TER	156.55943	296.46	46,413.61		0.18%		29.40%	
Truist Financial Corp	TFC	1241.00975	45.97	57,049.22	0.13%	4.52%	0.01%	9.34%	0.01%
Target Corp	TGT	452.85559	121.2	54,886.10	0.13%	3.76%	0.00%	5.00%	0.01%
TJX Cos Inc/The	TJX	1106.81065	159.7	176,757.66	0.41%	1.20%	0.00%	9.38%	0.04%
TKO Group Holdings Inc	TKO	77.96634	201.65	15,721.91		1.55%		80.03%	
Thermo Fisher Scientific Inc	TMO	371.48424	491.53	182,595.65	0.42%	0.38%	0.00%	6.56%	0.03%
T-Mobile US Inc	TMUS	1101.86274	210.03	231,424.23	0.53%	1.94%	0.01%	17.00%	0.09%
Texas Pacific Land Corp	TPL	68.94155	474.56	32,716.90	0.08%	0.51%	0.00%	10.00%	0.01%
Tapestry Inc	TPR	202.46422	141.11	28,569.73	0.07%	1.13%	0.00%	12.42%	0.01%
Targa Resources Corp	TRGP	214.80197	250.73	53,857.30	0.12%	1.99%	0.00%	17.00%	0.02%
Trimble Inc	TRMB	233.92941	65.23	15,259.22	0.04%			6.50%	0.00%
T Rowe Price Group Inc	TROW	217.60589	90.14	19,614.99	0.05%	5.77%	0.00%	5.94%	0.00%
Travelers Cos Inc/The	TRV	216.2379	291.68	63,072.27	0.15%	1.51%	0.00%	4.55%	0.01%
Tractor Supply Co	TSCO	526.00631	45.3	23,828.09	0.05%	2.12%	0.00%	9.18%	0.01%
Tesla Inc	TSLA	3752.43198	371.75	1,394,966.59	3.22%			10.50%	0.34%
Tyson Foods Inc	TSN	282.06996	64.07	18,072.22	0.04%	3.18%	0.00%	8.60%	0.00%
Trane Technologies PLC	TT	221.33191	416.74	92,237.86	0.21%	1.01%	0.00%	12.52%	0.03%
Trade Desk Inc/The	TTD	432.86842	22.69	9,821.78				20.70%	
Take-Two Interactive Software Inc	TTWO	185.17546	197.5	36,572.15				62.23%	
Texas Instruments Inc	TXN	910.46338	194.14	176,757.36	0.41%	2.93%	0.01%	9.31%	0.04%
Textron Inc	TXT	174.09889	87.56	15,244.10	0.04%	0.09%	0.00%	11.82%	0.00%
Tyler Technologies Inc	TYL	42.4537	342.38	14,535.30	0.03%			10.50%	0.00%
United Airlines Holdings Inc	UAL	327.70387	92.07	30,171.70	0.07%			13.97%	0.01%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Avg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Uber Technologies Inc	UBER	2042.94634	71.93	146,949.13	0.34%			3.27%	0.01%
UDR Inc	UDR	328.57196	33.78	11,099.16	0.03%	5.15%	0.00%	3.84%	0.00%
Universal Health Services Inc	UHS	53.83786	178.97	9,635.36	0.02%	0.45%	0.00%	9.91%	0.00%
Ulta Beauty Inc	ULTA	43.73663	522.71	22,861.57	0.05%			8.10%	0.00%
UnitedHealth Group Inc	UNH	907.67584	270.59	245,608.01	0.57%	3.27%	0.02%	6.47%	0.04%
Union Pacific Corp	UNP	593.6783	242.62	144,038.23	0.33%	2.28%	0.01%	8.61%	0.03%
United Parcel Service Inc	UPS	745.6334	98.38	73,355.41	0.17%	6.67%	0.01%	4.84%	0.01%
United Rentals Inc	URI	62.88632	728.56	45,816.46	0.11%	1.08%	0.00%	12.02%	0.01%
US Bancorp	USB	1552.25218	52.01	80,732.64	0.19%	4.00%	0.01%	9.61%	0.02%
Visa Inc	V	1681.09394	302.24	508,093.83	1.17%	0.89%	0.01%	12.19%	0.14%
VICI Properties Inc	VICI	1068.989	27.32	29,204.78	0.07%	6.59%	0.00%	8.00%	0.01%
Valero Energy Corp	VLO	298.95367	247.08	73,865.47	0.17%	1.94%	0.00%	10.93%	0.02%
Veralto Corp	VLTO	245.56512	88.42	21,712.87	0.05%	0.59%	0.00%	8.50%	0.00%
Vulcan Materials Co	VMC	130.46225	272.3	35,524.87	0.08%	0.76%	0.00%	10.38%	0.01%
Verisk Analytics Inc	VRSK	137.94189	189.75	26,174.47	0.06%	1.05%	0.00%	9.12%	0.01%
VeriSign Inc	VRSN	91.7	248.36	22,774.61	0.05%	1.30%	0.00%	8.00%	0.00%
Vertiv Holdings Co	VRT	382.59846	250.58	95,871.52		0.10%		31.14%	
Vertex Pharmaceuticals Inc	VRTX	254.03419	446.54	113,436.43	0.26%			11.42%	0.03%
Vistra Corp	VST	338.54929	150.33	50,894.11		0.61%		32.00%	
Ventas Inc	VTR	474.96522	81.78	38,842.66	0.09%	2.54%	0.00%	16.78%	0.02%
Viatris Inc	VTRS	1151.39292	13.51	15,555.32	0.04%	3.55%	0.00%	3.33%	0.00%
Verizon Communications Inc	VZ	4217.68417	50.2	211,727.75	0.49%	5.64%	0.03%	2.50%	0.01%
Westinghouse Air Brake Technologies Corp	WAB	170.1719	249.91	42,527.66	0.10%	0.50%	0.00%	13.87%	0.01%
Waters Corp	WAT	98.10187	297.8	29,214.74	0.07%			9.10%	0.01%
Warner Bros Discovery Inc	WBD	2506.76839	27.46	68,835.86					
Workday Inc	WDAY	210	129.92	27,283.20					
Western Digital Corp	WDC	339.03792	270.49	91,706.37		0.18%		51.11%	
WEC Energy Group Inc	WEC	325.69961	115.77	37,706.24	0.09%	3.29%	0.00%	6.00%	0.01%
Welltower Inc	WELL	697.75253	197.71	137,952.65		1.50%		22.54%	
Wells Fargo & Co	WFC	3085.63564	79.61	245,647.45	0.57%	2.26%	0.01%	10.83%	0.06%
Waste Management Inc	WM	403.33578	229.79	92,682.53	0.21%	1.64%	0.00%	8.74%	0.02%
Williams Cos Inc/The	WMB	1222.85695	72.78	88,999.53	0.21%	2.89%	0.01%	16.69%	0.03%
Walmart Inc	WMT	7972.4025	124.28	990,810.18	2.28%	0.80%	0.02%	10.14%	0.23%
W R Berkley Corp	WRB	374.49086	66.28	24,821.25	0.06%	0.54%	0.00%	8.55%	0.00%
Williams-Sonoma Inc	WSM	119.01605	182.33	21,700.20	0.05%	1.67%	0.00%	6.12%	0.00%
West Pharmaceutical Services Inc	WST	72.08161	250.64	18,066.53	0.04%	0.35%	0.00%	8.06%	0.00%
Willis Towers Watson PLC	WTW	94.2031	290.7	27,384.84	0.06%	1.32%	0.00%	10.00%	0.01%
Weyerhaeuser Co	WY	720.665	24.43	17,605.85		3.44%		-1.50%	
Wynn Resorts Ltd	WYNN	104.0434	101.55	10,565.61		0.98%		27.00%	
Xcel Energy Inc	XEL	623.87681	79.44	49,560.77	0.11%	2.98%	0.00%	7.00%	0.01%
Exxon Mobil Corp	XOM	4166.76345	169.66	706,933.09		2.43%		-1.50%	
Xylem Inc/NY	XYL	240.82645	119.5	28,778.76	0.07%	1.44%	0.00%	8.50%	0.01%
Block Inc	XYZ	539.103	60.18	32,443.22					
Yum! Brands Inc	YUM	276.43013	155.48	42,979.36	0.10%	1.93%	0.00%	8.75%	0.01%
Zimmer Biomet Holdings Inc	ZBH	195.652	90.42	17,690.85	0.04%	1.06%	0.00%	6.17%	0.00%
Zebra Technologies Corp	ZBRA	49.1917	209.08	10,285.00	0.02%			7.00%	0.00%
Zoetis Inc	ZTS	422.12771	118.21	49,899.72	0.12%	1.79%	0.00%	8.00%	0.01%

Notes:

[1] Equals sum of Col. [9]

[2] Equals sum of Col. [11]

[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

[4] Bloomberg Professional as of March 31, 2026

[5] Bloomberg Professional as of March 31, 2026

[6] Equals [4] x [5]

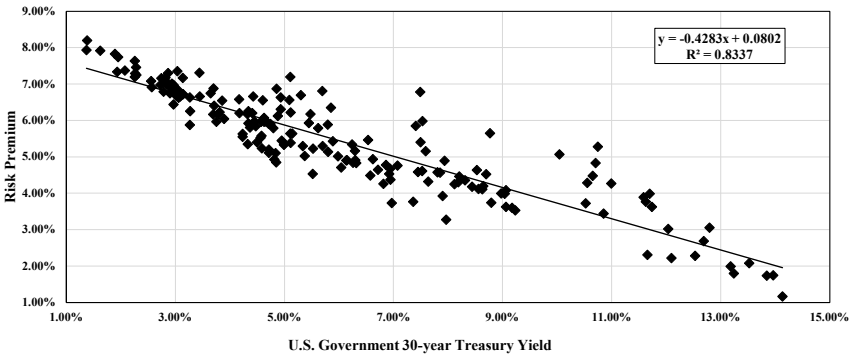
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%

[8] Source: Bloomberg Professional, as of March 31, 2026

[9] Equals [7] x [8]

[10] Average of Value Line and Bloomberg, as of March 31, 2026

[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9130636
R Square	0.8336851
Adjusted R Square	0.8327763
Standard Error	0.0057774
Observations	185

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03062	0.03062	917.32242	0.00000
Residual	183	0.00611	0.00003		
Total	184	0.03673			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0802	0.00	84.35	0.0000	0.0783	0.0820	0.0783	0.0820
U.S. Govt. 30-year Treasury	(0.4283)	0.01	(30.29)	0.0000	(0.4562)	(0.4004)	(0.4562)	(0.4004)

	[6]	[7]	[8]
	U.S. Govt. 30-year Treasury [7]	Risk Premium [8]	ROE [9]
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.80%	5.96%	10.76%
Blue Chip Near-Term Projected Forecast (May 2026 - October 2027) [5]	5.03%	5.86%	10.89%
AVERAGE			10.83%

Notes:
[1] Regulatory Research Associates, rate cases through March 31, 2026
[2] S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] S&P Capital IQ Pro, 30-day average as of March 31, 2026
[5] Bloomberg Professional
[6] See notes [4], [5] & [6]
[7] Equals 0.080164 + (-0.428281 x Column [7])
[8] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1980.1	13.97%	11.66%	2.31%
1980.2	14.25%	10.52%	3.73%
1980.3	14.30%	10.85%	3.45%
1980.4	14.32%	12.10%	2.23%
1981.1	14.82%	12.53%	2.28%
1981.2	15.05%	13.24%	1.81%
1981.3	15.31%	14.13%	1.17%
1981.4	15.59%	13.85%	1.74%
1982.1	15.71%	13.96%	1.75%
1982.2	15.60%	13.52%	2.08%
1982.3	15.85%	12.79%	3.06%
1982.4	16.03%	10.75%	5.28%
1983.1	15.54%	10.71%	4.83%
1983.2	15.13%	10.65%	4.48%
1983.3	15.39%	11.62%	3.77%
1983.4	15.37%	11.74%	3.63%
1984.1	15.06%	12.04%	3.02%
1984.2	15.18%	13.18%	2.00%
1984.3	15.38%	12.69%	2.69%
1984.4	15.69%	11.70%	3.99%
1985.1	15.48%	11.58%	3.90%
1985.2	15.27%	11.00%	4.27%
1985.3	14.84%	10.55%	4.29%
1985.4	15.11%	10.04%	5.07%
1986.1	14.42%	8.77%	5.65%
1986.2	14.27%	7.49%	6.78%
1986.3	13.26%	7.40%	5.86%
1986.4	13.52%	7.53%	5.99%
1987.1	12.90%	7.49%	5.40%
1987.2	13.17%	8.53%	4.64%
1987.3	13.14%	9.06%	4.08%
1987.4	12.76%	9.23%	3.53%
1988.1	12.74%	8.63%	4.11%
1988.2	12.70%	9.06%	3.63%
1988.3	12.78%	9.18%	3.60%
1988.4	12.97%	8.97%	4.00%
1989.1	13.02%	9.04%	3.99%
1989.2	13.22%	8.70%	4.52%
1989.3	12.38%	8.12%	4.26%
1989.4	12.83%	7.93%	4.90%
1990.1	12.62%	8.44%	4.19%
1990.2	12.85%	8.65%	4.20%
1990.3	12.54%	8.79%	3.75%
1990.4	12.68%	8.56%	4.12%
1991.1	12.66%	8.20%	4.46%
1991.2	12.67%	8.31%	4.36%
1991.3	12.49%	8.19%	4.30%
1991.4	12.42%	7.85%	4.57%
1992.1	12.38%	7.81%	4.58%
1992.2	11.83%	7.90%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.76%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.32%	4.84%
1993.4	11.04%	6.14%	4.91%
1994.1	11.07%	6.58%	4.49%
1994.2	11.13%	7.36%	3.77%
1994.3	12.75%	7.59%	5.16%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.72%	4.65%
1995.4	11.58%	6.24%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.97%	3.73%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.82%	4.26%
1997.2	11.62%	6.94%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.15%	4.91%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.48%	6.17%
1998.4	12.30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.80%	5.14%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%
2000.1	11.21%	6.30%	4.92%
2000.2	11.00%	5.98%	5.02%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.45%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.53%	5.23%
2001.4	11.99%	5.30%	6.69%
2002.1	10.05%	5.52%	4.53%
2002.2	11.41%	5.62%	5.79%
2002.3	11.65%	5.09%	6.56%
2002.4	11.57%	4.93%	6.63%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2004.2	10.64%	5.34%	5.30%
2004.3	10.75%	5.11%	5.64%
2004.4	11.24%	4.93%	6.31%
2005.1	10.63%	4.71%	5.92%
2005.2	10.31%	4.47%	5.84%
2005.3	11.08%	4.42%	6.66%
2005.4	10.63%	4.65%	5.98%
2006.1	10.70%	4.63%	6.07%
2006.2	10.79%	5.14%	5.64%
2006.3	10.35%	5.00%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.79%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.96%
2008.3	10.43%	4.45%	5.98%
2008.4	10.39%	3.64%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.25%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.37%	5.81%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.20%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.70%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.94%	7.01%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.16%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.27%	6.63%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.05%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.70%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.25%
2019.4	9.89%	2.26%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.19%
2020.3	9.30%	1.37%	7.93%
2020.4	9.54%	1.62%	7.92%
2021.1	9.45%	2.07%	7.38%
2021.2	9.55%	2.26%	7.30%
2021.3	9.27%	1.93%	7.34%
2021.4	9.69%	1.95%	7.74%
2022.1	9.45%	2.25%	7.20%
2022.2	9.88%	3.05%	6.83%
2022.3	9.14%	3.26%	5.88%
2022.4	9.94%	3.89%	6.04%
2023.1	9.72%	3.75%	5.97%
2023.2	10.04%	3.81%	6.23%
2023.3	9.79%	4.23%	5.55%
2023.4	9.82%	4.58%	5.24%
2024.1	9.67%	4.32%	5.35%
2024.2	10.16%	4.58%	5.58%
2024.3	9.86%	4.23%	5.63%
2024.4	9.90%	4.50%	5.40%
2025.1	9.83%	4.72%	5.11%
2025.2	9.95%	4.84%	5.11%
2025.3	9.70%	4.85%	4.85%
2025.4	9.91%	4.71%	5.20%
2026.1	9.75%	4.82%	4.93%
AVERAGE	11.45%	6.01%	5.44%
MEDIAN	10.94%	5.11%	5.55%

FLOTATION COST ADJUSTMENT

Company	Ticker	Date [i]	[1] Shares Issued (000)	[2] Offering Price	[3] Under-writing Discount [ii]	[4] Offering Expense ($000)	[5] Net Proceeds Per Share	[6] Total Flotation Costs ($000)	[7] Gross Equity Issue Before Costs ($000)	[8] Net Proceeds ($000)	[9] Flotation Cost Percentage
CMS Energy Corporation	CMS	3/30/2005	23,000	12.25	0.429	325	11.81	10,187	281,750	271,563	3.62%
CMS Energy Corporation	CMS	10/7/2004	32,775	9.10	0.319	325	8.77	10,764	298,253	287,489	3.61%
								$ 20,951	$ 580,003	$ 559,051	3.61%

[i] Offering Completion Date
[ii] Underwriting discount is calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9639, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

Company	Ticker	[10] Annualized Dividend	[11] Stock Price	[12] Dividend Yield	[13] Expected Dividend Yield	[14] Expected Dividend Yield Adjusted for Flotation Costs	[15] Value Line Earnings Growth	[16] S&P Capital IQ Projected EPS Growth Rate	[17] Zacks Projected EPS Growth Rate	[18] Average Earnings Growth	[19] Cost of Equity: Mean Growth Rate	[20] Cost of Equity Adjusted for Flotation Costs
Alliant Energy Corporation	LNT	$ 2.14	$ 71.23	3.00%	3.11%	3.22%	6.00%	7.48%	7.20%	6.89%	10.00%	10.12%
Ameren Corporation	AEE	$ 3.00	$ 110.05	2.73%	2.83%	2.94%	6.50%	7.77%	9.30%	7.86%	10.69%	10.80%
American Electric Power Company, Inc.	AEP	$ 3.80	$ 131.04	2.90%	3.00%	3.12%	6.50%	8.30%	6.70%	7.17%	10.17%	10.28%
Avista Corporation	AVA	$ 1.97	$ 40.07	4.92%	5.08%	5.27%	6.50%	6.19%	7.10%	6.60%	11.68%	11.87%
Dominion Resources, Inc.	D	$ 2.67	$ 62.44	4.28%	4.45%	4.61%	6.50%	7.01%	10.30%	7.94%	12.38%	12.55%
DTE Energy Company	DTE	$ 4.66	$ 145.81	3.20%	3.30%	3.42%	5.50%	7.02%	7.10%	6.54%	9.84%	9.96%
Duke Energy Corporation	DUK	$ 4.26	$ 129.90	3.28%	3.38%	3.51%	6.00%	6.57%	n/a	6.29%	9.67%	9.80%
Entergy Corporation	ETR	$ 2.56	$ 105.15	2.43%	2.53%	2.63%	3.00%	9.86%	11.50%	8.12%	10.65%	10.75%
Evergy, Inc.	EVRG	$ 2.78	$ 81.52	3.41%	3.54%	3.68%	6.50%	7.92%	9.10%	7.84%	11.38%	11.52%
IDACORP, Inc.	IDA	$ 3.52	$ 141.27	2.49%	2.59%	2.68%	6.00%	8.55%	8.00%	7.52%	10.10%	10.20%
NextEra Energy, Inc.	NEE	$ 2.49	$ 91.99	2.71%	2.81%	2.92%	8.00%	7.19%	n/a	7.60%	10.41%	10.52%
OGE Energy Corporation	OGE	$ 1.70	$ 47.85	3.55%	3.64%	3.78%	3.00%	6.49%	5.80%	5.10%	8.74%	8.88%
Pinnacle West Capital Corporation	PNW	$ 3.64	$ 100.24	3.63%	3.74%	3.88%	5.00%	7.48%	5.80%	6.09%	9.84%	9.98%
PPL Corporation	PPL	$ 1.14	$ 37.76	3.02%	3.13%	3.25%	7.50%	7.41%	7.30%	7.40%	10.53%	10.65%
Southern Company	SO	$ 2.96	$ 96.11	3.08%	3.19%	3.31%	6.50%	7.63%	7.20%	7.11%	10.30%	10.42%
Xcel Energy Inc.	XEL	$ 2.37	$ 80.62	2.94%	3.06%	3.17%	7.00%	8.70%	8.90%	8.20%	11.26%	11.37%
Mean											10.48%	10.60%	
Median											10.35%	10.47%	
Flotation Cost Adjustment (Mean)												0.13%	[21]
Flotation Cost Adjustment (Median)												0.11%	[22]

Notes:
[1] - [4] CMS Energy Corporation - Prospectus dated March 30, 2005 and Prospectus dated October 7, 2004.
[5] Equals [8]/[1]
[6] Equals [4] + ([1] x [3])
[7] Equals [1] x [2]
[8] Equals [7] - [6]
[9] Equals [6] / [7]
[10] Bloomberg Professional
[11] Bloomberg Professional, equals 30-day average as of March 31, 2026
[12] Equals [10] / [11]
[13] Equals [12] x (1 + 0.5 x [18])
[14] Equals [13] / (1 − Flotation Cost)
[15] Value Line
[16] S&P Capital IQ Pro
[17] Zacks Investment Research
[18] Equals Average of [15], [16], [17]
[19] Equals [13] + [18]
[20] Equals [14] + [18]
[21] Equals [20] (Mean) − [19] (Mean)
[22] Equals [20] (Median) − [19] (Median)

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF NET PLANT

($ Millions)

		[1]	[2]	[3]	[4]	[5]	[7]
		2025	2026	2027	2028	2029	Cap. Ex. / Net Plant
Alliant Energy Corporation	LNT						
Capital Spending per Share			$8.00	$8.00	$7.50	$7.00	
Common Shares Outstanding			257.50	257.50	258.75	260.00	
Capital Expenditures			$1,439.8	$1,442.0	$1,420.4	$1,398.6	28.0%
Net Plant		$20,344.0					
Ameren Corporation	AEE						
Capital Spending per Share			$12.85	$12.90	$12.95	$13.00	
Common Shares Outstanding			275.00	280.00	282.50	285.00	
Capital Expenditures			$3,533.8	$3,612.0	$3,658.4	$3,705.0	36.9%
Net Plant		$39,313.0					
American Electric Power Company, Inc.	AEP						
Capital Spending per Share			$14.10	$14.00	$14.00	$14.00	
Common Shares Outstanding			540.00	545.00	547.50	550.00	
Capital Expenditures			$7,614.0	$7,630.0	$7,665.0	$7,700.0	37.7%
Net Plant		$81,250.0					
Avista Corporation	AVA						
Capital Spending per Share			$6.45	$7.00	$8.25	$9.50	
Common Shares Outstanding			81.50	83.00	84.00	85.00	
Capital Expenditures			$525.7	$581.0	$693.0	$807.5	41.6%
Net Plant		$6,260.0					
Dominion Resources, Inc.	D						
Capital Spending per Share			$12.75	$10.50	$10.75	$11.00	
Common Shares Outstanding			870.00	865.00	897.50	930.00	
Capital Expenditures			$11,092.5	$9,082.5	$9,648.1	$10,230.0	50.9%
Net Plant		$78,725.0					
DTE Energy Company	DTE						
Capital Spending per Share			$32.00	$33.70	$34.88	$36.05	
Common Shares Outstanding			207.80	207.80	207.90	208.00	
Capital Expenditures			$6,649.6	$7,002.9	$7,250.5	$7,498.4	84.4%
Net Plant		$33,653.0					
Duke Energy Corporation	DUK						
Capital Spending per Share			$16.75	$17.25	$18.00	$18.75	
Common Shares Outstanding			779.00	780.00	781.50	783.00	
Capital Expenditures			$13,048.3	$13,455.0	$14,067.0	$14,681.3	42.8%
Net Plant		$129,200.0					
Entergy Corporation	ETR						
Capital Spending per Share			$12.00	$12.50	$13.25	$14.00	
Common Shares Outstanding			455.00	460.00	465.00	470.00	
Capital Expenditures			$5,460.0	$5,750.0	$6,161.3	$6,580.0	45.3%
Net Plant		$52,854.0					
Evergy, Inc.	EVRG						
Capital Spending per Share			$14.75	$15.70	$17.68	$19.65	
Common Shares Outstanding			230.50	230.50	230.50	230.50	
Capital Expenditures			$3,399.9	$3,618.9	$4,074.1	$4,529.3	59.4%
Net Plant		$26,302.0					
IDACORP, Inc.	IDA						
Capital Spending per Share			$20.00	$19.75	$19.75	$19.75	
Common Shares Outstanding			55.00	$55.50	55.75	56.00	
Capital Expenditures			$1,100.0	$1,096.1	$1,101.1	$1,106.0	59.6%
Net Plant		$7,385.0					

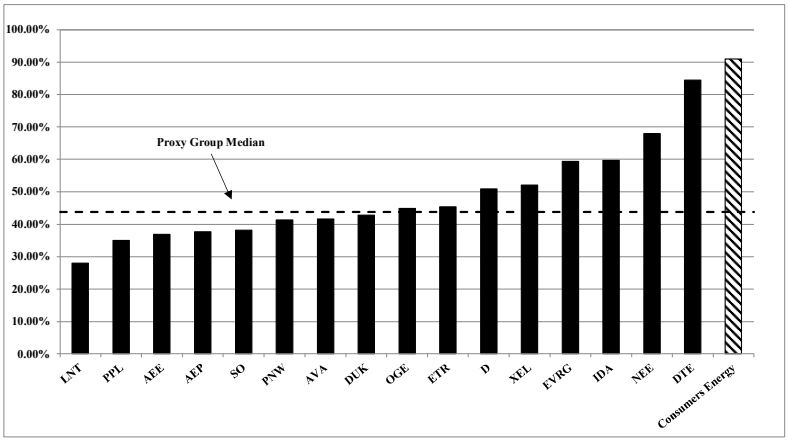
PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF NET PLANT

($ Millions)

		[1]	[2]	[3]	[4]	[5]	[7]
		2025	2026	2027	2028	2029	Cap. Ex. / Net Plant
NextEra Energy, Inc.	NEE						
Capital Spending per Share			$12.00	$12.25	$12.38	$12.50	
Common Shares Outstanding			2110.00	2135.00	2177.50	2220.00	
Capital Expenditures			$25,320.0	$26,153.8	$26,946.6	$27,750.0	68.0%
Net Plant		$156,197.0					
OGE Energy Corporation	OGE						
Capital Spending per Share			$6.70	$7.35	$7.05	$6.75	
Common Shares Outstanding			207.00	207.00	207.00	207.00	
Capital Expenditures			$1,386.9	$1,521.5	$1,459.4	$1,397.3	44.8%
Net Plant		$12,860.0					
Pinnacle West Capital Corporation	PNW						
Capital Spending per Share			$16.75	$17.00	$17.25	$17.50	
Common Shares Outstanding			120.00	121.00	123.00	125.00	
Capital Expenditures			$2,010.0	$2,057.0	$2,121.8	$2,187.5	41.4%
Net Plant		$20,225.0					
PPL Corporation	PPL						
Capital Spending per Share			$3.75	$3.85	$3.93	$4.00	
Common Shares Outstanding			737.50	737.60	$737.80	738.00	
Capital Expenditures			$2,765.6	$2,839.8	$2,895.9	$2,952.0	35.0%
Net Plant		$32,700.0					
Southern Company	SO						
Capital Spending per Share			$8.70	$8.65	$8.58	$8.50	
Common Shares Outstanding			1110.00	1115.00	$1,117.50	1120.00	
Capital Expenditures			$9,657.0	$9,644.8	$9,582.6	$9,520.0	38.2%
Net Plant		$100,500.0					
Xcel Energy Inc.	XEL						
Capital Spending per Share			$15.70	$13.50	$13.25	$13.00	
Common Shares Outstanding			591.60	593.50	$596.75	600.00	
Capital Expenditures			$9,288.1	$8,012.3	$7,906.9	$7,800.0	52.1%
Net Plant		$63,400.0					
Consumers Energy Company	Consumers Energy						
Capital Expenditures [8]			$4,100.00	$4,400.00	$3,900.00	$3,900.00	91.0%
Net Plant [9]		$17,906.2					

Notes:
[1] - [6] Value Line dated January 16, 2026, February 6, 2026, and March 3, 2026.
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Company Provided Data
[9] Company Provided Data

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF NET PLANT



	Company		Percent
1	Alliant Energy Corporation	LNT	28.02%
2	PPL Corporation	PPL	35.03%
3	Ameren Corporation	AEE	36.91%
4	American Electric Power Company, Inc.	AEP	37.67%
5	Southern Company	SO	38.21%
6	Pinnacle West Capital Corporation	PNW	41.42%
7	Avista Corporation	AVA	41.65%
8	Duke Energy Corporation	DUK	42.76%
9	OGE Energy Corporation	OGE	44.83%
10	Entergy Corporation	ETR	45.32%
11	Dominion Resources, Inc.	D	50.88%
12	Xcel Energy Inc.	XEL	52.06%
13	Evergy, Inc.	EVRG	59.40%
14	IDACORP, Inc.	IDA	59.62%
15	NextEra Energy, Inc.	NEE	67.97%
16	DTE Energy Company	DTE	84.39%
17	Consumers Energy Company	Consumers Energy	91.03%
	Proxy Group Median		43.80%
	Consumers Energy / Proxy Group		2.08

Notes:
Source: Exhibit No. A-14 (AEB-1), Schedule D-5, pages 27-28, col. [7]

REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Stabilization: Revenue Decoupling	[3] Revenue Stabilization: Formula-Based Rates	[4] Revenue Stabilization: Straight Fixed Variable Rate Design	[5] Overall Revenue Stabilization	[6] Capital Cost Recovery
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Fully Forecast	No	No	No	No	No
	Interstate Power & Light Co.	Iowa	Gas	Fully Forecast	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Electric	Fully Forecast	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Gas	Fully Forecast	No	No	No	No	No
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Ameren Illinois Co.	Illinois	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Union Electric Co.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
	Union Electric Co.	Missouri	Gas	Historical	Yes	No	No	Yes	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Historical	No	Yes	No	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Historical	Yes	No	No	Yes	Yes
	Southwestern Electric Power Co.	Louisiana	Electric	Historical	No	Yes	No	Yes	No
	Indiana Michigan Power Co.	Michigan	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Ohio Power Co.	Ohio	Electric	Partially Forecast	No	No	No	No	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes
	Kingsport Power Co.	Tennessee	Electric	Historical	No	No	No	No	No
	AEP Texas	Texas	Electric	Historical	No	No	No	No	Yes
	Southwestern Electric Power Co.	Texas	Electric	Historical	No	No	No	No	No
	Appalachian Power Co.	Virginia	Electric	Historical	No	No	No	No	No
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Historical	No	No	No	No	Yes
Avista Corporation	Alaska Electric Light and Power Co.	Alaska	Electric	Historical	No	No	No	No	No
	Avista Corp.	Idaho	Electric	Historical	Yes	No	No	Yes	Yes
	Avista Corp.	Idaho	Gas	Historical	Yes	No	No	Yes	Yes
	Avista Corp.	Oregon	Gas	Fully Forecast	Yes	No	No	Yes	No
	Avista Corp.	Washington	Electric	Historical	Yes	No	No	Yes	Yes
	Avista Corp.	Washington	Gas	Historical	Yes	No	No	Yes	Yes
Dominion Resources, Inc.	Dominion Energy Virginia	North Carolina	Electric	Historical	Yes	No	No	Yes	Yes
	Dominion Energy South Carolina	South Carolina	Electric	Historical	No	No	No	No	Yes
	Dominion Energy South Carolina	South Carolina	Gas	Historical	Yes	No	No	Yes	Yes
	Dominion Energy Virginia	Virginia	Electric	Partially Forecast	No	No	No	No	Yes
DTE Energy Company	DTE Electric Co.	Michigan	Electric	Fully Forecast	No	No	No	No	Yes
	DTE Gas Co.	Michigan	Gas	Fully Forecast	Yes	No	No	Yes	Yes
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Fully Forecast	No	No	No	No	Yes
	Duke Energy Indiana LLC	Indiana	Electric	Historical	Yes	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	No
	Duke Energy Kentucky Inc.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	No
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	North Carolina	Electric	Historical	Yes	Yes	No	Yes	No
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	Historical	Yes	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Electric	Partially Forecast	Yes	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	South Carolina	Electric	Historical	No	No	No	No	No
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Historical	No	No	No	No	No
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Fully Forecast	No	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Partially Forecast	No	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Partially Forecast	No	Yes	No	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Electric	Historical	No	Yes	No	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Historical	No	Yes	No	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Fully Forecast	No	Yes	No	Yes	Yes
	Entergy Texas Inc.	Texas	Electric	Fully Forecast	No	No	No	No	Yes
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	Historical	Yes	No	No	Yes	Yes
	Evergy Metro Inc.	Kansas	Electric	Historical	No	No	No	No	Yes
	Evergy Metro Inc	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
	Evergy Missouri West Inc.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Partially Forecast	Yes	No	No	Yes	No
	Idaho Power Co.	Oregon	Electric	Partially Forecast	No	No	No	No	No
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Fully Forecast	No	No	No	No	Yes

REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Stabilization: Revenue Decoupling	[3] Revenue Stabilization: Formula-Based Rates	[4] Revenue Stabilization: Straight Fixed Variable Rate Design	[5] Overall Revenue Stabilization	[6] Capital Cost Recovery
OGE Energy Corporation	Oklahoma Gas and Electric Company	Arkansas	Electric	Historical	No	Yes	No	Yes	Yes
	Oklahoma Gas and Electric Company	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes
Pinnacle West Capital Corporation	Arizona Public Service Co.	Arizona	Electric	Historical	Yes	No	No	Yes	Yes
PPL Corporation	Kentucky Utilities Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Louisville Gas & Electric Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Louisville Gas & Electric Co.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	PPL Electric Utilities Corp.	Pennsylvania	Electric	Fully Forecast	No	No	No	No	Yes
	Narragansett Electric Co.	Rhode Island	Electric	Historical	Yes	No	No	Yes	Yes
	Narragansett Electric Co.	Rhode Island	Gas	Historical	Yes	No	No	Yes	Yes
	Kentucky Utilities Co.	Virginia	Electric	Historical	No	No	No	No	No
Southern Company	Alabama Power Co.	Alabama	Electric	Fully Forecast	No	Yes	No	Yes	Yes
	Georgia Power Co.	Georgia	Electric	Fully Forecast	No	No	No	No	Yes
	Atlanta Gas & Light Co.	Georgia	Gas	Fully Forecast	Yes	Yes	Yes	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Yes	No	Yes	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Historical	Yes	Yes	No	Yes	Yes
	Virginia Natural Gas Inc.	Virginia	Gas	Partially Forecast	Yes	No	Yes	Yes	Yes
Xcel Energy	Public Service Co. of Colorado	Colorado	Electric	Historical	Yes	No	No	Yes	Yes
	Public Service Co. of Colorado	Colorado	Gas	Historical	Yes	No	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Southwestern Public Service Co.	New Mexico	Electric	Fully Forecast	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Electric	Fully Forecast	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	Fully Forecast	No	No	Yes	Yes	No
	Northern States Power Co.-Minnesota	South Dakota	Electric	Historical	Yes	No	No	Yes	Yes
	Southwestern Public Service Co.	Texas	Electric	Historical	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	Fully Forecast	No	No	No	No	Yes
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Fully Forecast	No	No	No	No	Yes
Proxy Group Totals									
				Fully Forecast 34					
				Partially Forecast 9				Yes 55	64
				Historical 41				No 29	20
				% Forecast 51.2%				% Yes 65.5%	76.2%
Consumers Energy [9]		Michigan	Electric	Fully Forecast	No	No	No	No	Yes

Notes:
[1] Regulatory Research Associates, effective as of March 31, 2026.
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September, 2025. Operating subsidiaries not covered in this report were excluded from this exhibit. Designated "Yes" if full or partial decoupling.
[3] S&P Capital IQ Pro, Alternative Regulation
[4] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 2025.
[5] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[6] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 2025. Designated "Yes" if noted by S&P as a having a capital tracker to recover either "Traditional generation", "Renewables/Non-traditional generation", "Delivery infrastructure", or "Environmental compliance".
[8] Data provided by the Company.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

THOMAS P. CLARK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Weadock BESS Project – Milestone Schedule

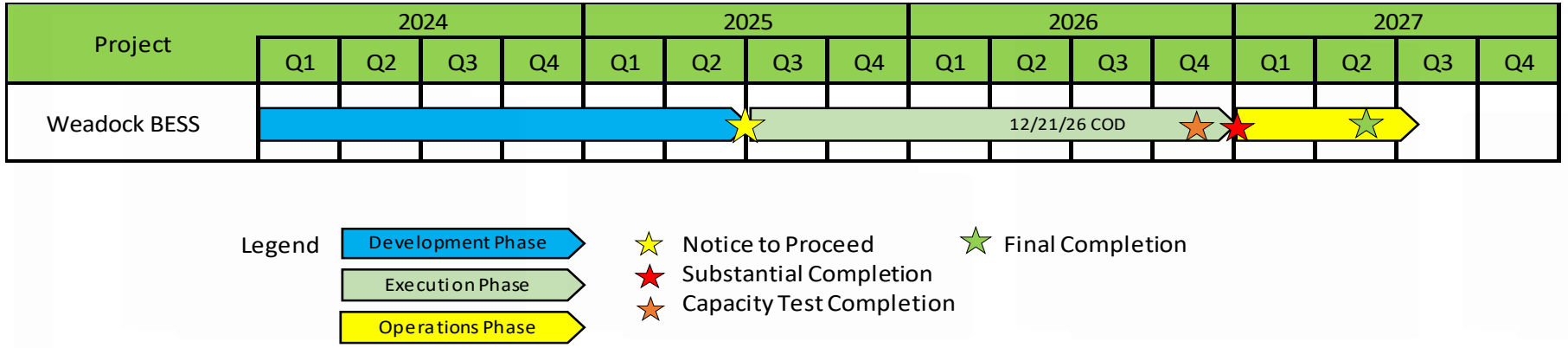


EXHIBIT A-47 (TPC-2)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-48 (TPC-3)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-49 (TPC-4)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-50 (TPC-5)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-51 (TPC-6)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-52 (TPC-7)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-53 (TPC-8)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-54 (TPC-9)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

Iosco BESS Project – Milestone Schedule

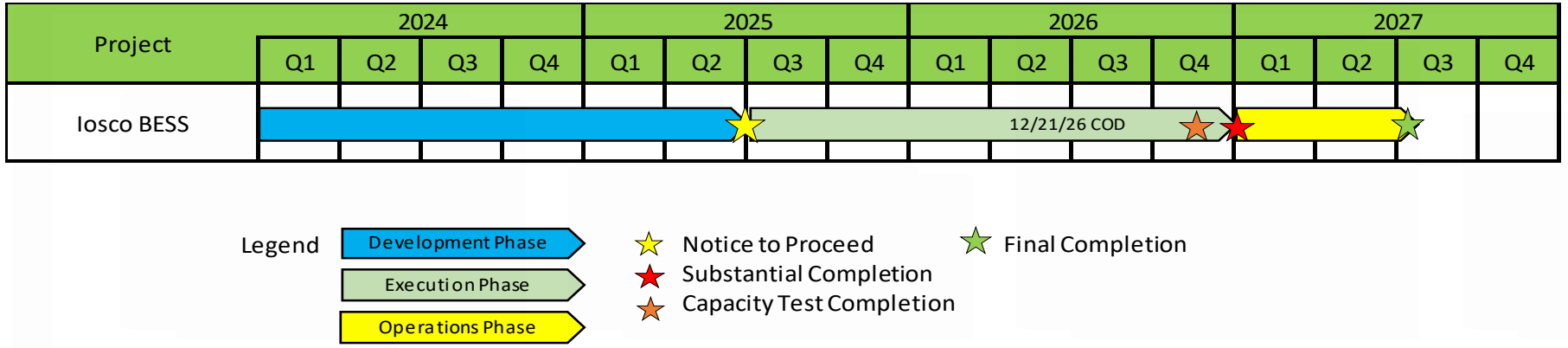


EXHIBIT A-56 (TPC-11)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-57 (TPC-12)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-58 (TPC-13)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-59 (TPC-14)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-60 (TPC-15)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-61 (TPC-16)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-62 (TPC-17)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-63 (TPC-18)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

LAURA M. CONNOLLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Large Load Scenarios

Case No.: U-22070
Exhibit No.: A-64 (LMC-1)
Page: 1 of 1
Witness: LMConnolly
Date: June 2026

Line No.	Description	(a) Proposal 1	(b) Proposal 2	(c) Proposal 3	(d) Proposal 4 As Ordered in U-21870	(e) Proposal 5	(f) Proposal 6 Same as 5
		Ave Rate per kWh					
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	$ 0.1961	$ 0.1961	$ 0.1926	**$ 0.2069**	$ 0.2063	$ 0.2063
2	Smart Hours RSH	0.1969	0.1969	0.1935	**0.2078**	0.2072	0.2072
3	Night Time Savers RPM	0.1921	0.1921	0.1887	**0.2027**	0.2021	0.2021
4	Non-Transmitting Meters RSM	0.2042	0.2042	0.2009	**0.2149**	0.2144	0.2144
5	Total Residential Class	0.1961	0.1961	0.1927	**0.2069**	0.2063	0.2063
	Secondary Class						
6	Energy-only GS	0.1701	0.1701	0.1689	**0.1805**	0.1798	0.1798
7	Time-of-Use GSTU	0.1690	0.1690	0.1678	**0.1802**	0.1795	0.1795
8	Demand GSD	0.1462	0.1462	0.1460	**0.1568**	0.1561	0.1561
9	Total Secondary	0.1602	0.1602	0.1594	**0.1707**	0.1699	0.1699
	Primary Class						
10	Energy-only GP	0.1076	0.1076	0.1089	**0.1180**	0.1174	0.1174
11	Demand GPD	0.0724	0.0802	0.0828	**0.0905**	0.0900	0.0900
12	Large Load		0.0675	0.0705	**-**	0.0128	0.0128
13	Time-of-Use GPTU	0.0921	0.0942	0.0964	**0.1048**	0.1041	0.1041
14	Energy Intensive EIP	0.0670	0.0640	0.0685	**0.0768**	0.0764	0.0764
15	Total Primary	0.0782	0.0786	0.0813	**0.0977**	0.0607	0.0607
	Lighting & Unmetered Class						
16	Metered Lighting GML	0.1692	0.1692	0.1818	**0.1758**	0.1755	0.1755
17	Universal Unmetered Lighting UUL	0.5950	0.5950	0.6049	**0.5931**	0.5927	0.5927
18	Unmetered GU	0.1029	0.1029	0.1059	**0.1127**	0.1121	0.1121
19	Total Lighting & Unmetered	0.2704	0.2704	0.2763	**0.2761**	0.2756	0.2756
	Self-generation Class						
20	Small Self-generation GSG-1						
21	Large Self-generation GSG-2	0.1002	0.0968	0.0968	**0.1012**	0.1011	0.1011
22	Total Self-generation	0.1002	0.0968	0.0968	**0.1012**	0.1011	0.1011
23	Total Full Service	0.1333	0.1335	0.1335	**0.1611**	0.1302	0.1302
	ROA SERVICE						
	Secondary Class						
24	Energy-only GS	0.0714	0.0714	0.0714	**0.0699**	0.0699	0.0699
25	Demand GSD	0.0612	0.0612	0.0612	**0.0604**	0.0603	0.0603
26	Total Secondary	0.0622	0.0622	0.0622	**0.0613**	0.0612	0.0612
	Primary Class						
27	Energy-only GP	0.0254	0.0255	0.0255	**0.0249**	0.0248	0.0248
28	Demand GPD	0.0086	0.0085	0.0085	**0.0094**	0.0093	0.0093
29	Total Primary	0.0090	0.0088	0.0088	**0.0097**	0.0097	0.0097
30	Total ROA Service	0.0118	0.0117	0.0117	**0.0125**	0.0125	0.0125
31	Total Jurisdictional Service	0.1230	0.1232	0.1232	**0.1456**	0.1202	0.1202

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Total Revenues

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
Page: 1 of 31
Witness: LMConnolly
Date: June 2026

Proposal 1

Line No.	Description	Customers	Sales	Revenue Present	Revenue Proposed	Net Increase / (Decrease) Revenue	Net Increase / (Decrease) Percent
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Mthly	MWh	$000	$000	$000	%
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	1,628,594	12,230,766	$ 2,530,673	$ 2,427,340	$ (103,334)	(4.1)
2	Smart Hours RSH	24,351	177,999	36,984	35,478	(1,506)	(4.1)
3	Night Time Savers RPM	16,879	168,382	34,132	32,750	(1,382)	(4.0)
4	Non-Transmitting Meters RSM	10,973	108,263	23,269	22,373	(897)	(3.9)
5	Total Residential Class	1,680,798	12,685,410	$ 2,625,059	$ 2,517,940	$ (107,118)	(4.1)
	Secondary Class						
6	Energy-only GS	204,973	4,114,839	$ 742,820	$ 708,365	$ (34,456)	(4.6)
7	Time-of-Use GSTU	1,891	84,563	15,240	14,467	(773)	(5.1)
8	Demand GSD	20,152	2,979,606	467,090	441,145	(25,945)	(5.6)
9	Total Secondary	227,015	7,179,008	$ 1,225,150	$ 1,163,977	$ (61,174)	(5.0)
	Primary Class						
10	Energy-only GP	1,360	666,952	$ 78,703	$ 72,777	$ (5,926)	(7.5)
11	Demand GPD	856	12,919,360	455,727	948,478	492,751	108.1
12	Time-of-Use GPTU	1,517	4,273,401	448,020	399,270	(48,750)	(10.9)
13	Energy Intensive EIP	17	392,565	30,168	26,700	(3,467)	(11.5)
14	Total Primary	3,749	18,252,279	$ 1,012,617	$ 1,447,225	$ 434,609	42.9
	Lighting & Unmetered Class						
15	Metered Lighting GML	399	10,776	$ 1,895	$ 1,836	$ (59)	(3.1)
16	Universal Unmetered Lighting UUL	4,696	54,640	32,405	32,724	319	1.0
17	Unmetered GU	465	99,352	11,196	10,346	(850)	(7.6)
18	Total Lighting & Unmetered	5,560	164,769	$ 45,496	$ 44,905	$ (590)	(1.3)
	Self-generation Class						
19	Small Self-generation GSG-1	-	-	$ -	$ -	$ -	NA
20	Large Self-generation GSG-2	14	173,301	17,543	17,373	(171)	(1.0)
21	Total Self-generation	14	173,301	$ 17,543	$ 17,373	$ (171)	(1.0)
22	Total Full Service	1,917,136	38,454,766	$ 4,925,865	$ 5,191,421	$ 265,555	5.4
	ROA SERVICE						
	Secondary Class						
23	Energy-only GS	85	18,702	$ 1,307	$ 1,344	$ 37	2.8
24	Demand GSD	472	174,288	10,522	10,744	222	2.1
25	Total Secondary	556	192,989	$ 11,829	$ 12,089	$ 259	2.2
	Primary Class						
26	Energy-only GP	60	72,068	$ 1,792	$ 1,845	$ 54	3.0
27	Demand GPD	356	3,303,873	30,932	28,621	(2,311)	(7.5)
28	Total Primary	417	3,375,942	$ 32,723	$ 30,466	$ (2,258)	(6.9)
29	Total ROA Service	973	3,568,931	$ 44,553	$ 42,554	$ (1,998)	(4.5)
30	Total Jurisdictional Service	1,918,109	42,023,697	$ 4,970,418	$ 5,233,975	$ 263,557	5.3
31	Plus: Rounding			-	1		
32	Total Jurisdictional Revenues			$ 4,970,418	$ 5,233,977	$ 263,559	5.3
33	Less: PSCR Factor Revenues			299,823	374,011	74,188	
34	Less: DR Surcharge			-	51,821	51,821	
35	Less: IRM Surcharge			-	13,927	13,927	
36	Total Jurisdictional Base Revenues			$ 4,670,595	$ 4,794,217	$ 123,622	2.6
37	Total Jurisdictional Revenues			4,970,418	5,233,977	263,559	5.3
38	Plus: ERC Deferral Surcharge			-	24,323	24,323	
39	Total Jurisdictional Revenues Requested			$ 4,970,418	$ 5,258,299	$ 287,881	5.8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Production & Transmission Revenues

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
Page: 2 of 31
Witness: LMConnolly
Date: June 2026

Proposal 1

Line No.	Description	(a) Sales	(b) Present Revenue	(c) Proposed Revenue	(d) Net Increase / (Decrease) Revenue	(e) Net Increase / (Decrease) Percent	(f)
		MWh	$000	$000	$000	%	
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	12,230,766	$ 1,259,128	$ 1,132,129	$ (126,999)	(10.1)	
2	Smart Hours RSH	177,999	18,333	16,482	(1,851)	(10.1)	
3	Night Time Savers RPM	168,382	17,006	15,298	(1,708)	(10.0)	
4	Non-Transmitting Meters RSM	108,263	11,022	9,916	(1,106)	(10.0)	
5	Total Residential Class	12,685,410	$ 1,305,488	$ 1,173,825	$ (131,663)	(10.1)	
	Secondary Class						
6	Energy-only GS	4,114,839	$ 408,019	$ 365,611	$ (42,408)	(10.4)	
7	Time-of-Use GSTU	84,563	8,915	7,978	(936)	(10.5)	
8	Demand GSD	2,979,606	279,684	250,017	(29,667)	(10.6)	
9	Total Secondary	7,179,008	$ 696,618	$ 623,607	$ (73,011)	(10.5)	
	Primary Class						
10	Energy-only GP	666,952	$ 61,147	$ 54,739	$ (6,408)	(10.5)	
11	Demand GPD	12,919,360	397,720	866,620	468,900	117.9	
12	Time-of-Use GPTU	4,273,401	367,811	327,685	(40,126)	(10.9)	
13	Energy Intensive EIP	392,565	27,016	23,504	(3,512)	(13.0)	
14	Total Primary	18,252,279	$ 853,693	$ 1,272,548	$ 418,854	49.1	
	Lighting & Unmetered Class						
15	Metered Lighting GML	10,776	$ 579	$ 499	$ (80)	(13.7)	
16	Universal Unmetered Lighting UUL	54,640	2,776	2,363	(413)	(14.9)	
17	Unmetered GU	99,352	7,762	6,852	(911)	(11.7)	
18	Total Lighting & Unmetered	164,769	$ 11,117	$ 9,714	$ (1,403)	(12.6)	
	Self-generation Class						
19	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA	
20	Large Self-generation GSG-2	173,301	14,136	14,136	-	-	
21	Total Self-generation	173,301	$ 14,136	$ 14,136	$ -	-	
22	Total Full Service	38,454,766	$ 2,881,052	$ 3,093,829	$ 212,777	7.4	
	ROA SERVICE						
	Secondary Class						
23	Energy-only GS	-	$ -	$ -	$ -	NA	
24	Demand GSD	-	-	-	-	NA	
25	Total Secondary	-	$ -	$ -	$ -	NA	
	Primary Class						
26	Energy-only GP	-	$ -	$ -	$ -	NA	
27	Demand GPD	-	-	-	-	NA	
28	Total Primary	-	$ -	$ -	$ -	NA	
29	Total ROA Service	-	$ -	$ -	$ -	NA	
30	Total Jurisdictional Service	38,454,766	$ 2,881,052	$ 3,093,829	$ 212,777	7.4	
31	Plus: Rounding		-	5	5		
32	Total Jurisdictional Base Revenues		$ 2,881,052	$ 3,093,834	$ 212,782	7.4	
33	Less: PSCR Factor Revenues		299,823	374,011	74,188		
34	Less: DR Surcharge		-	51,821	51,821		
35	Less: IRM Surcharge		-	-	-		
36	Total Jurisdictional Base Revenues		$ 2,581,229	$ 2,668,002	$ 86,772	3.4	
37	Total Jurisdictional Revenues		2,881,052	3,093,834	212,782	7.4	
38	Plus: ERC Deferral Surcharge		-	-	-		
39	Total Jurisdictional Revenues Requested		$ 2,881,052	$ 3,093,834	$ 212,782	7.4	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Delivery Revenues

Proposal 1

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
Page: 3 of 31
Witness: LMConnolly
Date: June 2026

Line No.	Description	(a) Sales	(b) Revenue Present	(c) Revenue Proposed	(d) Net Increase / (Decrease) Revenue	(e) Net Increase / (Decrease) Percent	(f)
		MWh	$000	$000	$000	%	
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	12,230,766	$ 1,271,545	$ 1,295,211	$ 23,665	1.9	
2	Smart Hours RSH	177,999	18,652	18,996	344	1.8	
3	Night Time Savers RPM	168,382	17,126	17,452	326	1.9	
4	Non-Transmitting Meters RSM	108,263	12,248	12,457	209	1.7	
5	Total Residential Class	12,685,410	$ 1,319,571	$ 1,344,115	$ 24,545	1.9	
	Secondary Class						
6	Energy-only GS	4,114,839	$ 334,801	$ 342,754	$ 7,953	2.4	
7	Time-of-Use GSTU	84,563	6,325	6,488	163	2.6	
8	Demand GSD	2,979,606	187,406	191,128	3,722	2.0	
9	Total Secondary	7,179,008	$ 528,533	$ 540,370	$ 11,838	2.2	
	Primary Class						
10	Energy-only GP	666,952	$ 17,556	$ 18,039	$ 483	2.7	
11	Demand GPD	12,919,360	58,006	81,857	23,851	41.1	
12	Time-of-Use GPTU	4,273,401	80,209	71,585	(8,624)	(10.8)	
13	Energy Intensive EIP	392,565	3,152	3,197	45	1.4	
14	Total Primary	18,252,279	$ 158,924	$ 174,678	$ 15,754	9.9	
	Lighting & Unmetered Class						
15	Metered Lighting GML	10,776	$ 1,316	$ 1,336	$ 20	1.6	
16	Universal Unmetered Lighting UUL	54,640	29,629	30,360	731	2.5	
17	Unmetered GU	99,352	3,434	3,494	60	1.8	
18	Total Lighting & Unmetered	164,769	$ 34,379	$ 35,191	$ 812	2.4	
	Self-generation Class						
19	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA	
20	Large Self-generation GSG-2	173,301	3,408	3,237	(171)	(5.0)	
21	Total Self-generation	173,301	$ 3,408	$ 3,237	$ (171)	(5.0)	
22	Total Full Service	38,454,766	$ 2,044,813	$ 2,097,591	$ 52,778	2.6	
	ROA SERVICE						
	Secondary Class						
23	Energy-only GS	18,702	$ 1,307	$ 1,344	$ 37	2.8	
24	Demand GSD	174,288	10,522	10,744	222	2.1	
25	Total Secondary	192,989	$ 11,829	$ 12,089	$ 259	2.2	
	Primary Class						
26	Energy-only GP	72,068	$ 1,792	$ 1,845	$ 54	3.0	
27	Demand GPD	3,303,873	30,932	28,621	(2,311)	(7.5)	
28	Total Primary	3,375,942	$ 32,723	$ 30,466	$ (2,258)	(6.9)	
29	Total ROA Service	3,568,931	$ 44,553	$ 42,554	$ (1,998)	(4.5)	
30	Total Jurisdictional Service	42,023,697	$ 2,089,366	$ 2,140,146	$ 50,780	2.4	
31	Plus: Rounding		-	(3)	(3)		
32	Total Jurisdictional Base Revenues		$ 2,089,366	$ 2,140,142	$ 50,777	2.4	
33	Less: PSCR Factor Revenues		-	-	-		
34	Less: DR Surcharge		-	-	-		
35	Less: IRM Surcharge		-	13,927	13,927		
36	Total Jurisdictional Base Revenues		$ 2,089,366	$ 2,126,215	$ 36,850	1.8	
37	Total Jurisdictional Revenues		2,089,366	2,140,142	50,777	2.4	
38	Plus: ERC Deferral Surcharge		-	24,323	24,323		
39	Total Jurisdictional Revenues Requested		$ 2,089,366	$ 2,164,465	$ 75,099	3.6	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Rate Design Targets
($000)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Jurisdictional	(c) Residential	(d) Secondary Class GS	(e) Secondary Class GSD	(f) Primary Class GP	(g) Primary Class GPD	(h) Primary Class GPTU	(i) Primary Class EIP	(j) Lighting & Unmetered Class GML	(k) Lighting & Unmetered Class UUL	(l) Lighting & Unmetered Class GU	(m) Self Gen. Class GSG-1	(n) Self Gen. Class GSG-2	Source
	Production														
1	Capacity (SRM)	$ 1,105,401	$ 488,807	$ 143,402	$ 91,125	$ 19,012	$ 244,993	$ 106,019	$ 7,036	$ 8	$ -	$ 1,868	$ -	$ 3,131	
	Capacity Adjustments [1]														
2	DR Revenue Requirement	(43,454)	(18,153)	(5,465)	(3,563)	(750)	(10,768)	(4,335)	(316)	(3)	(16)	(84)	-	-	WP-LMC-7
3	Self Generation	-	1,232	361	230	48	618	267	18	0	-	5	-	(2,778)	Alloc. Line 1
4	Total Adjustments	(43,454)	(16,921)	(5,103)	(3,334)	(702)	(10,150)	(4,068)	(299)	(3)	(16)	(79)	-	(2,778)	
5	Capacity (SRM) Design Target	$ 1,061,947	$ 471,885	$ 138,299	$ 87,791	$ 18,310	$ 234,843	$ 101,952	$ 6,737	$ 4	$ (16)	$ 1,789	$ -	$ 353	
6	Energy [2]	$ 855,907	$ 264,268	$ 95,523	$ 69,292	$ 15,670	$ 306,122	$ 101,363	$ 9,886	$ 280	$ 1,433	$ 2,536	$ -	$ (10,466)	
	Energy Adjustments [1]														
7	Self Generation	-	(3,192)	(1,154)	(837)	(189)	(3,698)	(1,224)	(119)	(3)	(17)	(31)	-	10,466	Alloc. Line 6
8	Total Adjustments	-	(3,192)	(1,154)	(837)	(189)	(3,698)	(1,224)	(119)	(3)	(17)	(31)	-	10,466	
9	Energy Design Target	$ 855,907	$ 261,075	$ 94,369	$ 68,455	$ 15,481	$ 302,424	$ 100,138	$ 9,767	$ 277	$ 1,416	$ 2,505	$ -	$ -	
10	Total Production	$ 1,917,854	$ 732,961	$ 232,668	$ 156,247	$ 33,790	$ 537,267	$ 202,090	$ 16,504	$ 281	$ 1,400	$ 4,294	$ -	$ 353	
11	**Transmission**														
12	Transmission	758,515	300,835	94,589	61,931	13,734	196,780	79,960	6,230	113	434	1,518	-	2,391	
13	Self Generation	-	951	299	196	43	622	253	20	0	1	5	-	(2,391)	Alloc. Line 12
14	Transmission Design Target	$ 758,515	$ 301,786	$ 94,888	$ 62,127	$ 13,778	$ 197,402	$ 80,213	$ 6,250	$ 113	$ 435	$ 1,522	$ -	$ -	
	Delivery														
15	Distribution [3]	$ 1,877,227	$ 1,159,835	$ 308,197	$ 188,863	$ 16,458	$ 97,950	$ 69,307	$ 1,201	$ 1,240	$ 28,563	$ 3,384	$ -	$ 2,229	
16	Customer	248,945	187,288	35,884	9,078	2,929	6,476	5,601	112	76	1,324	82	-	95	
17	Subtotal Delivery	2,126,172	1,347,124	344,081	197,941	19,386	104,426	74,908	1,312	1,316	29,887	3,466	-	2,324	
	Credit Adjustments [4]														
18	Substation Credits	$ (0)	$ 1,792	$ 476	$ 292	$ (8)	$ (1,376)	$ (346)	$ (323)	$ 2	$ 44	$ 5	$ -	$ (558)	WP-LMC-12
19	Life Line Credits	(0)	(13,629)	3,778	2,343	377	4,740	2,016	136	10	230	-	-	-	WP-LMC-9
20	Total Adjustments	(0)	(11,837)	4,254	2,634	370	3,364	1,670	(187)	12	274	5	-	(558)	
21	Total Delivery Design Target	$ 2,126,172	$ 1,335,286	$ 348,335	$ 200,576	$ 19,756	$ 107,790	$ 76,578	$ 1,126	$ 1,328	$ 30,161	$ 3,472	$ -	$ 1,766	
22	Total Rate Design Target	$ 4,802,541	$ 2,370,033	$ 675,890	$ 418,949	$ 67,324	$ 842,460	$ 358,881	$ 23,879	$ 1,722	$ 31,996	$ 9,288	$ -	$ 2,119	
23	DR Surcharge	$ 51,821	$ 21,649	$ 6,517	$ 4,249	$ 894	$ 12,841	$ 5,169	$ 377	$ 4	$ 19	$ 100	$ -	$ -	WP-LMC-19
24	IRM Surcharge	$ 13,970	$ 8,829	$ 2,252	$ 1,296	$ 128	$ 753	$ 467	$ 9	$ 9	$ 196	$ 23	$ -	$ 9	A-68 (LMC-7)
25	Total Revenue Requirement	$ 4,868,332	$ 2,400,511	$ 684,660	$ 424,495	$ 68,346	$ 856,053	$ 364,517	$ 24,266	$ 1,734	$ 32,211	$ 9,411	$ -	$ 2,128	

Notes
(1) Capacity and energy production costs adjusted to capture elements occurring outside the Cost-of-Service Study.
(2) Includes Non-SRM capacity related costs.
(3) Excludes IRM costs recovered through the IRM surcharge.
(4) Credit adjustments approved in Case No. U-21389

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Summer On-peak (RSP)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	814,657	MWh	@	0.060410	$ 49,214	0.033381	$ 27,194	$ (22,020)
2	Off-peak kWh	3,560,451	MWh	@	0.041347	147,215	0.022847	81,347	(65,868)
	Capacity								
3	On-peak kWh	814,657	MWh	@	0.053506	43,589	0.060335	49,152	5,563
4	Off-peak kWh	3,560,451	MWh	@	0.036622	130,390	0.041296	147,031	16,641
	Winter (Oct. - May)								
5	Non-capacity All kWh	7,855,392	MWh	@	0.033007	259,279	0.018238	143,270	(116,009)
6	Capacity All kWh	7,855,392	MWh	@	0.029234	229,647	0.032965	258,956	29,309
	Provisions								
	Device Cycling								
7	AC Cycling(1)	270,897	Bills	@	(5.00)	(1,354)	(5.00)	(1,354)	-
8	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
9	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
10	Peak Time Rewards	1,016	MWh	@	(0.50)	(508)	(0.50)	(508)	-
	Critical Peak Pricing								
11	Critical-peak Charge	266	MWh	@	1.00	266	1.00	266	-
12	Off-peak Credits	41,754	MWh	@	(0.006373)	(266)	(0.006373)	(266)	-
13	Annual PSCR Factor	12,230,766	MWh	@	0.009410	115,092	0.009410	115,092	-
14	Total Production					$ 972,564		$ 820,180	$ (152,384)
	Transmission								
	Summer (June - Sept.)								
15	On-peak kWh	814,657	MWh	@	0.037988	$ 30,947	0.038586	$ 31,434	$ 487
16	Off-peak kWh	3,560,451	MWh	@	0.026001	92,574	0.026410	94,031	1,458
	Winter (Oct. - May)								
17	All kWh	7,855,392	MWh	@	0.020756	163,043	0.021082	165,611	2,567
18	Total Transmission					$ 286,564		$ 291,077	$ 4,513
	Delivery								
19	System Access	19,543,128	Bills	@	8.00	$ 156,345	8.00	$ 156,345	$ -
20	Distribution	12,230,766	MWh	@	0.093333	1,141,532	0.094572	1,156,684	15,152
	Provisions								
21	Senior Citizen (RSC)	4,444,922	Bills	@	(4.00)	(17,780)	(4.00)	(17,780)	-
22	Low Income Credit (LIAC)	66,396	Bills	@	(42.00)	(2,789)	(42.00)	(2,789)	-
23	Income Assistance (RIA)	720,358	Bills	@	(8.00)	(5,763)	(8.00)	(5,763)	-
24	Total Delivery					$ 1,271,545		$ 1,286,698	$ 15,152
25	Total Full Service					$ 2,530,673		$ 2,397,954	$ (132,719)
	ROA SERVICE								
	Delivery								
26	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
27	Distribution	-	MWh	@	0.093333	-	0.094572	-	-
	Provisions								
28	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
29	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
30	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
31	Total Delivery					$ -		$ -	$ -
32	Total Full & ROA Service					$ 2,530,673		$ 2,397,954	$ (132,719)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Smart Hours (RSH)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	11,637	MWh	@	0.060410	$ 703	0.033381	$ 388	$ (315)
2	Off-peak kWh	54,082	MWh	@	0.041347	2,236	0.022847	1,236	(1,001)
	Capacity								
3	On-peak kWh	11,637	MWh	@	0.053506	623	0.060335	702	79
4	Off-peak kWh	54,082	MWh	@	0.036622	1,981	0.041296	2,233	253
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kWh	17,187	MWh	@	0.038335	659	0.021183	364	(295)
6	Off-peak kWh	95,088	MWh	@	0.031989	3,042	0.017676	1,681	(1,361)
	Capacity								
7	On-peak kWh	17,187	MWh	@	0.033954	584	0.038287	658	74
8	Off-peak kWh	95,088	MWh	@	0.028333	2,694	0.031949	3,038	344
	Provisions								
	Device Cycling								
9	AC Cycling(1)	3,816	Bills	@	(5.00)	(19)	(5.00)	(19)	-
10	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
11	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
12	Peak Time Rewards	30	MWh	@	(0.50)	(15)	(0.50)	(15)	-
	Critical Peak Pricing								
13	Critical-peak Charge	5	MWh	@	1.00	5	1.00	5	-
14	Off-peak Credits	1,456	MWh	@	(0.006373)	(9)	(0.006373)	(9)	-
15	Annual PSCR Factor	177,999	MWh	@	0.009410	1,675	0.009410	1,675	-
16	Total Production					$ 14,157		$ 11,937	$ (2,220)
	Transmission								
	Summer (June - Sept.)								
17	On-peak kWh	11,637	MWh	@	0.037988	$ 442	0.038586	$ 449	$ 7
18	Off-peak kWh	54,082	MWh	@	0.026001	1,406	0.026410	1,428	22
	Winter (Oct. - May)								
19	On-peak kWh	17,187	MWh	@	0.024106	414	0.024486	421	7
20	Off-peak kWh	95,088	MWh	@	0.020116	1,913	0.020432	1,943	30
21	Total Transmission					$ 4,175		$ 4,241	$ 66
	Delivery								
22	System Access	292,217	Bills	@	8.00	$ 2,338	8.00	$ 2,338	$ -
23	Distribution	177,999	MWh	@	0.093333	16,613	0.094572	16,834	221
	Provisions								
24	Senior Citizen (RSC)	48,048	Bills	@	(4.00)	(192)	(4.00)	(192)	-
25	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	13,378	Bills	@	(8.00)	(107)	(8.00)	(107)	-
27	Total Delivery					$ 18,652		$ 18,872	$ 221
28	Total Full Service					$ 36,984		$ 35,050	$ (1,934)
	ROA SERVICE								
	Delivery								
29	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
30	Distribution	-	MWh	@	0.093333	-	0.094572	-	-
	Provisions								
31	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
32	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
34	Total Delivery					$ -		$ -	$ -
35	Total Full & ROA Service					$ 36,984		$ 35,050	$ (1,934)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Nighttime Savers (RPM)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	9,384	MWh	@	0.060410	$ 567	0.033381	$ 313	$ (254)
2	Off-peak kWh	19,685	MWh	@	0.046196	909	0.025526	502	(407)
3	Super Off-peak kWh	33,466	MWh	@	0.037381	1,251	0.020656	691	(560)
	Capacity								
4	On-peak kWh	9,384	MWh	@	0.053506	502	0.060335	566	64
5	Off-peak kWh	19,685	MWh	@	0.040916	805	0.046138	908	103
6	Super Off-peak kWh	33,466	MWh	@	0.033109	1,108	0.037334	1,249	141
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	13,591	MWh	@	0.038335	521	0.021183	288	(233)
8	Off-peak kWh	33,262	MWh	@	0.035960	1,196	0.019871	661	(535)
9	Super Off-peak kWh	58,994	MWh	@	0.028890	1,704	0.015964	942	(763)
	Capacity								
10	On-peak kWh	13,591	MWh	@	0.033954	461	0.038287	520	59
11	Off-peak kWh	33,262	MWh	@	0.031850	1,059	0.035915	1,195	135
12	Super Off-peak kWh	58,994	MWh	@	0.025588	1,510	0.028854	1,702	193
	Provisions								
	Device Cycling								
13	AC Cycling(1)	4,141	Bills	@	(5.00)	(21)	(5.00)	(21)	-
14	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
15	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
16	Peak Time Rewards	23	MWh	@	(0.50)	(11)	(0.50)	(11)	-
	Critical Peak Pricing								
17	Critical-peak Charge	1	MWh	@	1.00	1	1.00	1	-
18	Off-peak Credits	1,417	MWh	@	(0.006373)	(9)	(0.006373)	(9)	-
19	Annual PSCR Factor	168,382	MWh	@	0.009410	1,584	0.009410	1,584	-
20	Total Production					$ 13,139		$ 11,083	$ (2,056)
	Transmission								
	Summer (June - Sept.)								
21	On-peak kWh	9,384	MWh	@	0.037988	$ 356	0.038586	$ 362	$ 6
22	Off-peak kWh	19,685	MWh	@	0.029049	572	0.029507	581	9
23	Super Off-peak kWh	33,466	MWh	@	0.023506	787	0.023876	799	12
	Winter (Oct. - May)								
24	On-peak kWh	13,591	MWh	@	0.024106	328	0.024486	333	5
25	Off-peak kWh	33,262	MWh	@	0.022613	752	0.022969	764	12
26	Super Off-peak kWh	58,994	MWh	@	0.018167	1,072	0.018453	1,089	17
27	Total Transmission					$ 3,866		$ 3,927	$ 61
	Delivery								
28	System Access	202,551	Bills	@	8.00	$ 1,620	8.00	$ 1,620	$ -
29	Separately Metered EV Charger	295	Bills	@	(8.00)	$ (2)	(8.00)	$ (2)	$ -
30	Distribution	168,382	MWh	@	0.093333	15,716	0.094572	15,924	209
	Provisions								
31	Senior Citizen (RSC)	41,852	Bills	@	(4.00)	(167)	(4.00)	(167)	-
32	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	5,053	Bills	@	(8.00)	(40)	(8.00)	(40)	-
34	Total Delivery					$ 17,126		$ 17,334	$ 209
35	Total Full Service					$ 34,132		$ 32,345	$ (1,787)
	ROA SERVICE								
	Delivery								
36	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
37	Distribution	-	MWh	@	0.093333	-	0.094572	-	-
	Provisions								
38	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
39	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
40	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
41	Total Delivery					$ -		$ -	$ -
42	Total Full & ROA Service					$ 34,132		$ 32,345	$ (1,787)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Non-Transmitting Meters (RSM)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	First 600 kWh	23,089	MWh	@	0.033007	$ 762	0.018238	$ 421	$ (341)
2	Excess kWh	14,767	MWh	@	0.060410	892	0.033381	493	(399)
	Capacity								
3	First 600 kWh	23,089	MWh	@	0.029234	675	0.032965	761	86
4	Excess kWh	14,767	MWh	@	0.053506	790	0.060335	891	101
	Winter (Oct. - May)								
5	Non-capacity All kWh	70,407	MWh	@	0.033007	2,324	0.018238	1,284	(1,040)
6	Capacity All kWh	70,407	MWh	@	0.029234	2,058	0.032965	2,321	263
7	Annual PSCR Factor	108,263	MWh	@	0.009410	1,019	0.009410	1,019	-
8	Total Production					$ 8,520		$ 7,190	$ (1,330)
	Transmission								
	Summer (June - Sept.)								
9	First 600 kWh	23,089	MWh	@	0.020756	$ 479	0.021082	$ 487	$ 8
10	Excess kWh	14,767	MWh	@	0.037988	561	0.038586	570	9
	Winter (Oct. - May)								
11	All kWh	70,407	MWh	@	0.020756	1,461	0.021082	1,484	23
12	Total Transmission					$ 2,502		$ 2,541	$ 39
	Delivery								
13	System Access	131,680	Bills	@	8.00	$ 1,053	8.00	$ 1,053	$ -
14	Opt-out Fee	100,852	Bills	@	12.61	1,272	12.61	1,272	-
15	Distribution	108,263	MWh	@	0.093333	10,104	0.094572	10,239	134
	Provisions								
16	Senior Citizen (RSC)	36,309	Bills	@	(4.00)	(145)	(4.00)	(145)	-
17	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
18	Income Assistance (RIA)	4,599	Bills	@	(8.00)	(37)	(8.00)	(37)	-
19	Total Delivery					$ 12,248		$ 12,382	$ 134
20	Total Full Service					$ 23,269		$ 22,113	$ (1,157)
	ROA SERVICE								
	Delivery								
21	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
22	Opt-out Fee	-	Bills	@	12.61	-	12.61	-	-
23	Distribution	-	MWh	@	0.093333	-	0.094572	-	-
	Provisions								
24	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
25	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
27	Total Delivery					$ -		$ -	$ -
28	Total Full & ROA Service					$ 23,269		$ 22,113	$ (1,157)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Energy-only (GS)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	1,447,697	MWh	@	0.046363	$ 67,119	0.027125	$ 39,269	$ (27,850)
2	Capacity All kWh	1,447,697	MWh	@	0.035056	50,750	0.039510	57,199	6,449
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,667,142	MWh	@	0.034013	90,716	0.019900	53,076	(37,641)
4	Capacity All kWh	2,667,142	MWh	@	0.025987	69,310	0.029289	78,118	8,808
5	Annual PSCR Factor	4,114,839	MWh	@	0.009410	38,721	0.009410	38,721	-
6	Total Production					$ 316,616		$ 266,383	$ (50,234)
	Transmission								
	Summer (June - Sept.)								
7	All kWh	1,447,697	MWh	@	0.026688	$ 38,636	0.027108	$ 39,245	$ 608
	Winter (Oct. - May)								
8	All kWh	2,667,142	MWh	@	0.019784	52,766	0.020095	53,597	831
9	Total Transmission					$ 91,403		$ 92,842	$ 1,439
	Delivery								
10	System Access	2,459,675	Bills	@	20.00	$ 49,193	20.00	$ 49,193	$ -
11	Distribution	4,114,839	MWh	@	0.069433	285,704	0.070829	291,451	5,747
	Provisions								
12	Education GEI	95,811	MWh	@	(0.001000)	(96)	(0.000914)	(88)	8
13	Total Delivery					$ 334,801		$ 340,557	$ 5,755
14	Total Full Service					$ 742,820		$ 699,782	$ (43,039)
	ROA SERVICE								
	Delivery								
15	System Access	1,014	Bills	@	20.00	$ 20	20.00	$ 20	$ -
16	Distribution	18,702	MWh	@	0.069433	1,299	0.070829	1,325	26
	Provisions								
17	Education GEI	11,475	MWh	@	(0.001000)	(11)	(0.000914)	(10)	1
18	Total Delivery					$ 1,307		$ 1,334	$ 27
19	Total Full & ROA Service					$ 744,128		$ 701,116	$ (43,012)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Time-of-Use (GSTU)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	14,873	MWh	@	0.062830	$ 934	0.036760	$ 547	$ (388)
2	Mid-peak kWh	11,717	MWh	@	0.048934	573	0.028630	335	(238)
3	Off-peak kWh	4,487	MWh	@	0.036694	165	0.021469	96	(68)
	Capacity								
4	On-peak kWh	14,873	MWh	@	0.047982	714	0.054080	804	91
5	Mid-peak kWh	11,717	MWh	@	0.037369	438	0.042118	494	56
6	Off-peak kWh	4,487	MWh	@	0.028063	126	0.031629	142	16
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	25,578	MWh	@	0.037107	949	0.021710	555	(394)
8	Off-peak kWh	27,907	MWh	@	0.030029	838	0.017569	490	(348)
	Capacity								
9	On-peak kWh	25,578	MWh	@	0.028428	727	0.032041	820	92
10	Off-peak kWh	27,907	MWh	@	0.022961	641	0.025879	722	81
	Provisions								
11	Interruptible (GSI)	-	MWh	@	(0.021695)	-	(0.021695)	-	-
12	Annual PSCR Factor	84,563	MWh	@	0.009410	796	0.009410	796	-
13	Total Production					$ 6,901		$ 5,801	$ (1,099)
	Transmission								
	Summer (June - Sept.)								
14	On-peak kWh	14,873	MWh	@	0.036529	$ 543	0.037105	$ 552	$ 9
15	Mid-peak kWh	11,717	MWh	@	0.028449	333	0.028897	339	5
16	Off-peak kWh	4,487	MWh	@	0.021365	96	0.021701	97	2
	Winter (Oct. - May)								
17	On-peak kWh	25,578	MWh	@	0.021643	554	0.021984	562	9
18	Off-peak kWh	27,907	MWh	@	0.017480	488	0.017756	496	8
19	Total Transmission					$ 2,014		$ 2,046	$ 32
	Delivery								
20	System Access	22,689	Bills	@	20.00	$ 454	20.00	$ 454	$ -
21	Distribution	84,563	MWh	@	0.069433	5,871	0.070829	5,990	118
	Provisions								
22	Education GEI	-	MWh	@	(0.001000)	-	(0.000914)	-	-
23	Total Delivery					$ 6,325		$ 6,443	$ 118
24	Total Full Service					$ 15,240		$ 14,290	$ (950)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Demand (GSD)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Peak kW	2,893	MW	@	6.10	$ 17,632	4.90	$ 14,163	$ (3,469)
2	All kWh	1,048,776	MWh	@	0.032526	34,112	0.016966	17,793	(16,319)
	Capacity								
3	Peak kW	2,893	MW	@	10.17	29,425	11.47	33,177	3,753
4	All kWh	1,048,776	MWh	@	-	-	-	-	-
	Winter (Oct. - May)								
	Non-capacity								
5	Peak kW	5,338	MW	@	2.89	15,402	2.32	12,372	(3,031)
6	All kWh	1,930,830	MWh	@	0.023861	46,072	0.012446	24,032	(22,041)
	Capacity								
7	Peak kW	5,338	MW	@	9.05	48,326	10.21	54,490	6,164
8	All kWh	1,930,830	MWh	@	-	-	-	-	-
9	Power Factor Adjustment					156		220	64
	Provisions								
10	Interruptible (GSI)-Summer	29	MW	@	(8.50)	(247)	(8.50)	(247)	-
11	Interruptible (GSI)-Winter	53	MW	@	(7.50)	(398)	(7.50)	(398)	-
12	Annual PSCR Factor	2,979,606	MWh	@	0.009410	28,038	0.009410	28,038	-
13	Total Production					$ 218,520		$ 183,641	$ (34,879)
	Transmission								
	Summer (June - Sept.)								
14	Peak kW	2,893	MW	@	8.00	$ 23,147	8.13	$ 23,512	$ 365
	Winter (Oct. - May)								
15	Peak kW	5,338	MW	@	7.12	38,017	7.23	38,615	599
16	Total Transmission					$ 61,164		$ 62,127	$ 963
	Delivery								
17	System Access	241,823	Bills	@	30.00	$ 7,255	30.00	$ 7,255	$ -
18	Peak kW	8,231	MW	@	1.00	8,231	1.00	8,231	-
19	Distribution	2,979,606	MWh	@	0.057650	171,774	0.058483	174,257	2,483
20	Power Factor Adjustment					254		257	4
	Provisions								
21	Education GEI	131,112	MWh	@	(0.000820)	(107)	(0.000743)	(97)	10
22	Total Delivery					$ 187,406		$ 189,903	$ 2,497
23	Total Full Service					$ 467,090		$ 435,671	$ (31,419)
	ROA SERVICE								
	Delivery								
24	System Access	5,663	Bills	@	30.00	$ 170	30.00	$ 170	$ -
25	Peak kW	344	MW	@	1.00	344	1.00	344	-
26	Distribution	174,288	MWh	@	0.057650	10,048	0.058483	10,193	145
27	Power Factor Adjustment					16		16	0
	Provisions								
28	Education GEI	68,199	MWh	@	(0.000820)	(56)	(0.000743)	(51)	5
29	Total Delivery					$ 10,522		$ 10,673	$ 151
30	Total Full & ROA Service					$ 477,612		$ 446,344	$ (31,268)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 1 (GP VL 1)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate	Present Revenue	Proposed Rate	Proposed Revenue	Net Increase / (Decrease)
					(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
					$/unit	$000	$/unit	$000	$000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	1,101	MWh	@	0.043974	$ 48	0.027149	$ 30	$ (19)
2	Capacity All kWh	1,101	MWh	@	0.027595	30	0.031128	34	4
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,353	MWh	@	0.032261	76	0.019917	47	(29)
4	Capacity All kWh	2,353	MWh	@	0.021049	50	0.023745	56	6
5	Power Factor Adjustment					3		3	(1)
6	Annual PSCR Factor	3,454	MWh	@	0.009410	33	0.009410	33	-
7	Total Production					$ 240		$ 202	$ (38)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	1,101	MWh	@	0.023364	$ 26	0.023732	$ 26	$ 0
	Winter (Oct. - May)								
9	All kWh	2,353	MWh	@	0.017822	42	0.018103	43	1
10	Total Transmission					$ 68		$ 69	$ 1
	Delivery								
11	System Access	49	Bills	@	100.00	$ 5	100.00	$ 5	$ -
12	Distribution	3,454	MWh	@	0.006957	24	0.009270	32	8
13	Substation Ownership Credit	700	MWh	@	(0.004093)	(3)	(0.004093)	(3)	-
14	Power Factor Adjustment					0		0	0
	Provisions								
15	Education GEI	-	MWh	@	(0.000578)	-	(0.000511)	-	-
16	Total Delivery					$ 26		$ 35	$ 8
17	Total Full Service					$ 334		$ 305	$ (29)
	ROA SERVICE								
	Delivery								
18	System Access	-	Bills	@	100.00	$ -	100.00	$ -	$ -
19	Distribution	-	MWh	@	0.006957	-	0.009270	-	-
20	Substation Ownership Credit	-	MWh	@	(0.004093)	-	(0.004093)	-	-
21	Power Factor Adjustment					-		-	-
	Provisions								
22	Education GEI	-	MWh	@	(0.000578)	-	(0.000511)	-	-
23	Total Delivery					$ -		$ -	$ -
24	Total Full & ROA Service					$ 334		$ 305	$ (29)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 2 (GP VL 2)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate	Present Revenue	Proposed Rate	Proposed Revenue	Net Increase / (Decrease)
					(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
					$/unit	$000	$/unit	$000	$000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	9,485	MWh	@	0.044489	$ 422	0.027466	$ 261	$ (161)
2	Capacity All kWh	9,485	MWh	@	0.027998	266	0.031583	300	34
	Winter (Oct. - May)								
3	Non-capacity All kWh	21,775	MWh	@	0.032638	711	0.020150	439	(272)
4	Capacity All kWh	21,775	MWh	@	0.021357	465	0.024091	525	60
5	Power Factor Adjustment					49		40	(9)
6	Annual PSCR Factor	31,259	MWh	@	0.009410	294	0.009410	294	-
7	Total Production					$ 2,206		$ 1,857	$ (349)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	9,485	MWh	@	0.023706	$ 225	0.024079	$ 228	$ 4
	Winter (Oct. - May)								
9	All kWh	21,775	MWh	@	0.018083	394	0.018367	400	6
10	Total Transmission					$ 619		$ 628	$ 10
	Delivery								
11	System Access	435	Bills	@	100.00	$ 43	100.00	$ 43	$ -
12	Distribution	31,259	MWh	@	0.010996	344	0.011169	349	5
13	Substation Ownership Credit	6,580	MWh	@	(0.004513)	(30)	(0.004513)	(30)	-
14	Power Factor Adjustment					8		8	0
	Provisions								
15	Education GEI	-	MWh	@	(0.000578)	-	(0.000511)	-	-
16	Total Delivery					$ 366		$ 371	$ 6
17	Total Full Service					$ 3,191		$ 2,857	$ (333)
	ROA SERVICE								
	Delivery								
18	System Access	24	Bills	@	100.00	$ 2	100.00	$ 2	$ -
19	Distribution	1,783	MWh	@	0.010996	20	0.011169	20	0
20	Substation Ownership Credit	-	MWh	@	(0.004513)	-	(0.004513)	-	-
21	Power Factor Adjustment					(0)		(0)	(0)
	Provisions								
22	Education GEI	-	MWh	@	(0.000578)	-	(0.000511)	-	-
23	Total Delivery					$ 22		$ 22	$ 0
24	Total Full & ROA Service					$ 3,212		$ 2,879	$ (333)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 3 (GP VL 3)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate	Present Revenue	Proposed Rate	Proposed Revenue	Net Increase / (Decrease)
					(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
					$/unit	$000	$/unit	$000	$000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	221,271	MWh	@	0.044937	$ 9,943	0.027743	$ 6,139	$ (3,805)
2	Capacity All kWh	221,271	MWh	@	0.028442	6,293	0.032084	7,099	806
	Winter (Oct. - May)								
3	Non-capacity All kWh	410,967	MWh	@	0.032967	13,548	0.020353	8,364	(5,184)
4	Capacity All kWh	410,967	MWh	@	0.021696	8,916	0.024474	10,058	1,142
5	Power Factor Adjustment					486		397	(88)
6	Annual PSCR Factor	632,239	MWh	@	0.009410	5,949	0.009410	5,949	-
7	Total Production					$ 45,136		$ 38,007	$ (7,130)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	221,271	MWh	@	0.024082	$ 5,329	0.024461	$ 5,413	$ 84
	Winter (Oct. - May)								
9	All kWh	410,967	MWh	@	0.018370	7,549	0.018659	7,668	119
10	Total Transmission					$ 12,878		$ 13,081	$ 203
	Delivery								
11	System Access	15,834	Bills	@	100.00	$ 1,583	100.00	$ 1,583	$ -
12	Distribution	632,239	MWh	@	0.024415	15,436	0.024958	15,780	344
13	Power Factor Adjustment					194		198	4
	Provisions								
14	Education GEI	85,102	MWh	@	(0.000578)	(49)	(0.000511)	(43)	6
15	Total Delivery					$ 17,164		$ 17,518	$ 354
16	Total Full Service					$ 75,178		$ 68,605	$ (6,573)
	ROA SERVICE								
	Delivery								
17	System Access	696	Bills	@	100.00	$ 70	100.00	$ 70	$ -
18	Distribution	70,285	MWh	@	0.024415	1,716	0.024958	1,754	38
19	Power Factor Adjustment					5		5	0
	Provisions								
20	Education GEI	36,890	MWh	@	(0.000578)	(21)	(0.000511)	(19)	2
21	Total Delivery					$ 1,770		$ 1,810	$ 41
22	Total Full & ROA Service					$ 76,948		$ 70,415	$ (6,532)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 1 (GPD VL 1)

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Line No.	(a) Description		(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE	**Present**	Proposed							
	Production									
	Summer (June - Sept.)									
	Non-capacity									
1	On-peak kW	668	4,268	MW	@	5.96	$ 3,979	6.05	$ 25,816	$ 21,837
2	On-peak kWh	86,218	964,618	MWh	@	0.040427	3,486	0.023377	22,550	19,064
3	Off-peak kWh	296,066	2,052,866	MWh	@	0.026219	7,762	0.015161	31,123	23,361
4	Capacity On-peak kW	668	4,268	MW	@	10.06	6,719	12.18	51,983	45,263
	Winter (Oct. - May)									
	Non-capacity									
5	On-peak kW	1,369	8,569	MW	@	5.15	7,050	5.23	44,783	37,733
6	On-peak kWh	179,258	1,928,858	MWh	@	0.025351	4,544	0.014659	28,276	23,731
7	Off-peak kWh	605,998	4,105,198	MWh	@	0.022012	13,339	0.012729	52,253	38,914
8	Capacity On-peak kW	1,369	8,569	MW	@	9.33	12,777	11.29	96,788	84,011
	Provisions									
9	Economic Development GED	-	-	MW	@	-	-	-	-	-
	Interruptible GI									
10	Summer Contracted kW	60	60	MW	@	(8.50)	(514)	(8.50)	(514)	-
11	Winter Contracted kW	121	121	MW	@	(7.50)	(905)	(7.50)	(905)	-
	Interruptible GI-2									
12	Summer Capacity & Transmission		-	MWh	@	0.029081	-	0.028186	-	-
13	Winter Capacity & Transmission		-	MWh	@	0.026985	-	0.026294	-	-
14	LMP		-	MWh	@	-	-	-	-	-
	Coincident Peak Provision									
15	Summer Capacity		-	MWh		-	-	0.025783	-	-
16	Summer Transmission		-	MWh		-	-	0.014425	-	-
17	Winter Capacity		-	MWh		-	-	0.023462	-	-
18	Winter Transmission		-	MWh		-	-	0.013483	-	-
19	Critical Peak Event		-	MWh		-	-	1.00	-	-
20	Power Factor Adjustment						(122)		(738)	(616)
21	Annual PSCR Factor	1,167,540	9,051,540	MWh	@	0.009410	10,987	0.009410	85,175	74,188
22	Total Production						$ 69,103		$ 436,590	$ 367,487
	Transmission									
	Summer (June - Sept.)									
23	On-peak kW	668	4,268	MW	@	9.13	$ 6,094	10.20	$ 43,527	$ 37,434
	Winter (Oct. - May)									
24	On-peak kW	1,369	8,569	MW	@	8.50	11,632	9.49	81,359	69,727
25	Total Transmission						$ 17,725		$ 124,886	$ 107,161
	Delivery									
26	System Access	267	279	Bills	@	200.00	$ 53	200.00	$ 56	$ 2
27	Maximum kW	2,528	13,328	MW	@	2.37	5,996	2.70	35,924	29,928
28	Substation Ownership	42	42	MW	@	(1.82)	(76)	(1.82)	(76)	-
29	Distribution	1,167,540	9,051,540	MWh	@	-	-	-	-	-
30	Power Factor Adjustment						(12)		(75)	(63)
	Provisions									
31	Education GEI	-	-	MWh	@	(0.000205)	-	(0.000231)	-	-
32	Total Delivery						$ 5,961		$ 35,828	$ 29,868
33	Total Full Service						$ 92,789		$ 597,304	$ 504,515
	ROA SERVICE									
	Delivery									
34	System Access	169	169	Bills	@	200.00	$ 34	200.00	$ 34	$ -
35	Maximum kW	2,403	2,403	MW	@	2.37	5,700	2.70	6,477	777
36	Substation Ownership	196	196	MW	@	(1.82)	(356)	(1.82)	(356)	-
37	Distribution	1,270,576	1,270,576	MWh	@	-	-	-	-	-
38	Power Factor Adjustment						(14)		(16)	(2)
	Provisions									
39	Education GEI	2,675	2,675	MWh	@	(0.000205)	(1)	(0.000231)	(1)	(0)
40	Total Delivery						$ 5,364		$ 6,138	$ 775
41	Total Full & ROA Service						$ 98,153		$ 603,442	$ 505,290

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 2 (GPD VL 2)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	886	MW	@	6.03	$ 5,340	6.12	$ 5,420	$ 80
2	On-peak kWh	121,063	MWh	@	0.040900	4,951	0.023650	2,863	(2,088)
3	Off-peak kWh	357,634	MWh	@	0.026526	9,486	0.015338	5,485	(4,001)
4	Capacity On-peak kW	886	MW	@	10.21	9,042	12.36	10,944	1,902
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,801	MW	@	5.21	9,381	5.29	9,521	140
6	On-peak kWh	240,894	MWh	@	0.025648	6,178	0.014831	3,573	(2,606)
7	Off-peak kWh	733,449	MWh	@	0.022270	16,334	0.012878	9,445	(6,889)
8	Capacity On-peak kW	1,801	MW	@	9.47	17,051	11.46	20,637	3,586
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	40	MW	@	(8.50)	(343)	(8.50)	(343)	-
11	Winter Contracted kW	81	MW	@	(7.50)	(608)	(7.50)	(608)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.031449	-	0.037602	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.029198	-	0.034895	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.034183	-	-
16	Summer Transmission	-	MWh		-	-	0.019143	-	-
17	Winter Capacity	-	MWh		-	-	0.030953	-	-
18	Winter Transmission	-	MWh		-	-	0.009405	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					(103)		(90)	13
21	Annual PSCR Factor	1,453,040	MWh	@	0.009410	13,673	0.009410	13,673	-
22	Total Production					$ 90,384		$ 80,521	$ (9,863)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	886	MW	@	9.26	$ 8,200	10.35	$ 9,164	$ 964
	Winter (Oct. - May)								
24	On-peak kW	1,801	MW	@	8.62	15,523	9.63	17,348	1,825
25	Total Transmission					$ 23,723		$ 26,511	$ 2,789
	Delivery								
26	System Access	721	Bills	@	200.00	$ 144	200.00	$ 144	$ -
27	Maximum kW	3,094	MW	@	3.61	11,178	3.13	9,681	(1,497)
28	Substation Ownership	269	MW	@	(1.93)	(520)	(1.93)	(520)	-
29	Distribution	1,453,040	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(14)		(12)	2
	Provisions								
31	Education GEI	29,734	MWh	@	(0.000205)	(6)	(0.000231)	(7)	(1)
32	Total Delivery					$ 10,782		$ 9,286	$ (1,495)
33	Total Full Service					$ 124,888		$ 116,319	$ (8,570)
	ROA SERVICE								
	Delivery								
34	System Access	453	Bills	@	200.00	$ 91	200.00	$ 91	$ -
35	Maximum kW	2,306	MW	@	3.61	8,331	3.13	7,216	(1,116)
36	Substation Ownership	298	MW	@	(1.93)	(576)	(1.93)	(576)	-
37	Distribution	1,080,207	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					16		13	(2)
	Provisions								
39	Education GEI	66,701	MWh	@	(0.000205)	(14)	(0.000231)	(15)	(2)
40	Total Delivery					$ 7,848		$ 6,729	$ (1,120)
41	Total Full & ROA Service					$ 132,737		$ 123,048	$ (9,689)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 3 (GPD VL 3)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	1,514	MW	@	6.09	$ 9,218	6.18	$ 9,357	$ 139
2	On-peak kWh	209,315	MWh	@	0.041312	8,647	0.023889	5,000	(3,647)
3	Off-peak kWh	587,189	MWh	@	0.026793	15,733	0.015493	9,097	(6,635)
4	Capacity On-peak kW	1,514	MW	@	10.37	15,697	12.55	19,004	3,307
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	3,075	MW	@	5.26	16,175	5.34	16,423	248
6	On-peak kWh	417,471	MWh	@	0.025907	10,815	0.014980	6,254	(4,562)
7	Off-peak kWh	1,200,805	MWh	@	0.022495	27,012	0.013007	15,619	(11,393)
8	Capacity On-peak kW	3,075	MW	@	9.62	29,583	11.64	35,800	6,217
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	4	MW	@	(8.50)	(34)	(8.50)	(34)	-
11	Winter Contracted kW	8	MW	@	(7.50)	(57)	(7.50)	(57)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.033010	-	0.039431	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.031900	-	0.037995	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.035607	-	-
16	Summer Transmission	-	MWh		-	-	0.019978	-	-
17	Winter Capacity	-	MWh		-	-	0.032271	-	-
18	Winter Transmission	-	MWh		-	-	0.018596	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					91		80	(11)
21	Annual PSCR Factor	2,414,780	MWh	@	0.009410	22,723	0.009410	22,723	-
22	Total Production					$ 155,603		$ 139,266	$ (16,338)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	1,514	MW	@	9.41	$ 14,244	10.51	$ 15,912	$ 1,669
	Winter (Oct. - May)								
24	On-peak kW	3,075	MW	@	8.76	26,938	9.79	30,093	3,155
25	Total Transmission					$ 41,182		$ 46,005	$ 4,823
	Delivery								
26	System Access	9,273	Bills	@	200.00	$ 1,855	200.00	$ 1,855	$ -
27	Maximum kW	5,899	MW	@	6.68	39,405	5.82	34,356	(5,049)
28	Distribution	2,414,780	MWh	@	-	-	-	-	-
29	Power Factor Adjustment					27		24	(3)
	Provisions								
30	Education GEI	110,078	MWh	@	(0.000204)	(22)	(0.000231)	(25)	(3)
31	Total Delivery					$ 41,264		$ 36,208	$ (5,056)
32	Total Full Service					$ 238,049		$ 221,479	$ (16,570)
	ROA SERVICE								
	Delivery								
33	System Access	3,656	Bills	@	200.00	$ 731	200.00	$ 731	$ -
34	Maximum kW	2,542	MW	@	6.68	16,982	5.82	14,806	(2,176)
35	Distribution	953,091	MWh	@	-	-	-	-	-
36	Power Factor Adjustment					37		32	(5)
	Provisions								
37	Education GEI	149,120	MWh	@	(0.000204)	(30)	(0.000231)	(34)	(4)
38	Total Delivery					$ 17,720		$ 15,535	$ (2,185)
39	Total Full & ROA Service					$ 255,769		$ 237,014	$ (18,755)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 1 (GPTU VL 1)

Case No.: U-22070
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	13,186	MWh	@	0.061877	$ 816	0.039165	$ 516	$ (299)
2	Mid-peak kWh	17,748	MWh	@	0.055068	977	0.034855	619	(359)
3	Low-peak kWh	48,608	MWh	@	0.044513	2,164	0.028175	1,370	(794)
4	Off-peak kWh	86,924	MWh	@	0.033174	2,884	0.020998	1,825	(1,058)
	Capacity								
5	High-peak kWh	13,186	MWh	@	0.035267	465	0.039765	524	59
6	Mid-peak kWh	17,748	MWh	@	0.031400	557	0.035405	628	71
7	Low-peak kWh	48,608	MWh	@	0.025306	1,230	0.028533	1,387	157
8	Off-peak kWh	86,924	MWh	@	0.018927	1,645	0.021341	1,855	210
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	26,006	MWh	@	0.039842	1,036	0.025218	656	(380)
10	Mid-peak kWh	36,415	MWh	@	0.036938	1,345	0.023380	851	(494)
11	Off-peak kWh	235,629	MWh	@	0.031011	7,307	0.019628	4,625	(2,682)
	Capacity								
12	High-peak kWh	26,006	MWh	@	0.022720	591	0.025617	666	75
13	Mid-peak kWh	36,415	MWh	@	0.021035	766	0.023717	864	98
14	Off-peak kWh	235,629	MWh	@	0.017499	4,123	0.019731	4,649	526
15	Power Factor Adjustment					42		34	(8)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	464,518	MWh	@	0.009410	4,371	0.009410	4,371	-
19	Total Production					$ 30,320		$ 25,441	$ (4,879)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	13,186	MWh	@	0.030861	$ 407	0.031347	$ 413	$ 6
21	Mid-peak kWh	17,748	MWh	@	0.027477	488	0.027910	495	8
22	Low-peak kWh	48,608	MWh	@	0.022144	1,076	0.022493	1,093	17
23	Off-peak kWh	86,924	MWh	@	0.016563	1,440	0.016824	1,462	23
24	Winter (Oct. - May)								
25	High-peak kWh	26,006	MWh	@	0.019881	517	0.020194	525	8
26	Mid-peak kWh	36,415	MWh	@	0.018407	670	0.018697	681	11
27	Off-peak kWh	235,629	MWh	@	0.015313	3,608	0.015554	3,665	57
28	Total Transmission					$ 8,206		$ 8,335	$ 129
	Delivery								
29	System Access	280	Bills	@	200.00	$ 56	200.00	$ 56	$ -
30	Maximum kW	1,315	MW	@	2.37	3,119	2.70	3,544	425
31	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
32	Distribution	464,518	MWh	@	-	-	-	-	-
33	Power Factor Adjustment					5		6	1
	Provisions								
34	Education GEI	39,403	MWh	@	(0.000205)	(8)	(0.000231)	(9)	(1)
35	Total Delivery					$ 3,172		$ 3,596	$ 425
36	Total Full Service					$ 41,698		$ 37,373	$ (4,325)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 2 (GPTU VL 2)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	16,699	MWh	@	0.062601	$ 1,045	0.039624	$ 662	$ (384)
2	Mid-peak kWh	22,367	MWh	@	0.055712	1,246	0.035263	789	(457)
3	Low-peak kWh	51,905	MWh	@	0.045034	2,337	0.028504	1,480	(858)
4	Off-peak kWh	84,694	MWh	@	0.033562	2,843	0.021243	1,799	(1,043)
	Capacity								
5	High-peak kWh	16,699	MWh	@	0.035782	598	0.040345	674	76
6	Mid-peak kWh	22,367	MWh	@	0.031859	713	0.035921	803	91
7	Low-peak kWh	51,905	MWh	@	0.025675	1,333	0.028950	1,503	170
8	Off-peak kWh	84,694	MWh	@	0.019204	1,626	0.021653	1,834	207
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	32,702	MWh	@	0.040309	1,318	0.025513	834	(484)
10	Mid-peak kWh	44,338	MWh	@	0.037370	1,657	0.023654	1,049	(608)
11	Off-peak kWh	243,938	MWh	@	0.031374	7,653	0.019858	4,844	(2,809)
	Capacity								
12	High-peak kWh	32,702	MWh	@	0.023051	754	0.025991	850	96
13	Mid-peak kWh	44,338	MWh	@	0.021342	946	0.024064	1,067	121
14	Off-peak kWh	243,938	MWh	@	0.017754	4,331	0.020019	4,883	552
15	Power Factor Adjustment					(12)		(10)	2
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	496,642	MWh	@	0.009410	4,673	0.009410	4,673	-
19	Total Production					$ 33,061		$ 27,734	$ (5,328)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	16,699	MWh	@	0.031312	$ 523	0.031805	$ 531	$ 8
21	Mid-peak kWh	22,367	MWh	@	0.027879	624	0.028318	633	10
22	Low-peak kWh	51,905	MWh	@	0.022468	1,166	0.022821	1,185	18
23	Off-peak kWh	84,694	MWh	@	0.016805	1,423	0.017069	1,446	22
	Winter (Oct. - May)								
24	High-peak kWh	32,702	MWh	@	0.020172	660	0.020489	670	10
25	Mid-peak kWh	44,338	MWh	@	0.018676	828	0.018970	841	13
26	Off-peak kWh	243,938	MWh	@	0.015536	3,790	0.015781	3,850	60
27	Total Transmission					$ 9,013		$ 9,155	$ 142
	Delivery								
28	System Access	963	Bills	@	200.00	$ 193	200.00	$ 193	$ -
29	Maximum kW	1,431	MW	@	3.61	5,168	3.13	4,476	(692)
30	Substation Ownership	235	MW	@	(1.93)	(453)	(1.93)	(453)	-
31	Distribution	496,642	MWh	@	-	-	-	-	-
32	Power Factor Adjustment					(2)		(2)	0
	Provisions								
33	Education GEI	18,544	MWh	@	(0.000205)	(4)	(0.000231)	(4)	(0)
34	Total Delivery					$ 4,902		$ 4,210	$ (692)
35	Total Full Service					$ 46,976		$ 41,099	$ (5,878)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 3 (GPTU VL 3)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	127,203	MWh	@	0.063232	$ 8,043	0.040023	$ 5,091	$ (2,952)
2	Mid-peak kWh	168,181	MWh	@	0.056274	9,464	0.035619	5,990	(3,474)
3	Low-peak kWh	375,163	MWh	@	0.045488	17,065	0.028792	10,802	(6,264)
4	Off-peak kWh	562,171	MWh	@	0.033901	19,058	0.021457	12,063	(6,995)
	Capacity								
5	High-peak kWh	127,203	MWh	@	0.036350	4,624	0.040986	5,214	590
6	Mid-peak kWh	168,181	MWh	@	0.032364	5,443	0.036491	6,137	694
7	Low-peak kWh	375,163	MWh	@	0.026083	9,785	0.029409	11,033	1,248
8	Off-peak kWh	562,171	MWh	@	0.019509	10,967	0.021997	12,366	1,399
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	216,061	MWh	@	0.040715	8,797	0.025771	5,568	(3,229)
10	Mid-peak kWh	295,549	MWh	@	0.037747	11,156	0.023892	7,061	(4,095)
11	Off-peak kWh	1,567,912	MWh	@	0.031690	49,687	0.020058	31,449	(18,237)
	Capacity								
12	High-peak kWh	216,061	MWh	@	0.023417	5,060	0.026403	5,705	645
13	Mid-peak kWh	295,549	MWh	@	0.021680	6,408	0.024445	7,225	817
14	Off-peak kWh	1,567,912	MWh	@	0.018036	28,279	0.020336	31,886	3,606
15	Power Factor Adjustment					456		370	(85)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	3,312,240	MWh	@	0.009410	31,168	0.009410	31,168	-
19	Total Production					$ 225,460		$ 189,128	$ (36,332)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	127,203	MWh	@	0.031809	$ 4,046	0.032310	$ 4,110	$ 64
21	Mid-peak kWh	168,181	MWh	@	0.028321	4,763	0.028767	4,838	75
22	Low-peak kWh	375,163	MWh	@	0.022824	8,563	0.023184	8,698	135
23	Off-peak kWh	562,171	MWh	@	0.017071	9,597	0.017340	9,748	151
	Winter (Oct. - May)								
24	High-peak kWh	216,061	MWh	@	0.020492	4,427	0.020814	4,497	70
25	Mid-peak kWh	295,549	MWh	@	0.018972	5,607	0.019271	5,695	88
26	Off-peak kWh	1,567,912	MWh	@	0.015783	24,746	0.016031	25,136	390
27	Total Transmission					$ 61,750		$ 62,722	$ 972
	Delivery								
28	System Access	16,957	Bills	@	200.00	$ 3,391	200.00	$ 3,391	$ -
29	Maximum kW	10,275	MW	@	6.68	68,640	5.82	59,845	(8,795)
30	Distribution	3,312,240	MWh	@	-	-	-	-	-
31	Power Factor Adjustment					161		141	(21)
	Provisions								
32	Education GEI	278,712	MWh	@	(0.000204)	(57)	(0.000231)	(64)	(8)
33	Total Delivery					$ 72,136		$ 63,312	$ (8,823)
34	Total Full Service					$ 359,346		$ 315,163	$ (44,183)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 1 (EIP VL 1)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	206	MWh	@	0.099498	$ 21	0.066850	$ 14	$ (7)
2	High-peak kWh	7,015	MWh	@	0.066332	465	0.044567	313	(153)
3	Mid-peak kWh	7,214	MWh	@	0.059487	429	0.039968	288	(141)
4	Low-peak kWh	45,458	MWh	@	0.047278	2,149	0.031765	1,444	(705)
5	Off-peak kWh	61,205	MWh	@	0.034619	2,119	0.023260	1,424	(695)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	206	MWh	@	0.040218	8	0.045508	9	1
8	High-peak kWh	7,015	MWh	@	0.026812	188	0.030339	213	25
9	Mid-peak kWh	7,214	MWh	@	0.023872	172	0.027012	195	23
10	Low-peak kWh	45,458	MWh	@	0.019239	875	0.021769	990	115
11	Off-peak kWh	61,205	MWh	@	0.014390	881	0.016282	997	116
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	647	MWh	@	0.062127	40	0.041742	27	(13)
13	High-peak kWh	14,105	MWh	@	0.041418	584	0.027828	393	(192)
14	Mid-peak kWh	14,704	MWh	@	0.038779	570	0.026054	383	(187)
15	Off-peak kWh	182,038	MWh	@	0.032609	5,936	0.021909	3,988	(1,948)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	647	MWh	@	0.025909	17	0.029317	19	2
18	High-peak kWh	14,105	MWh	@	0.017272	244	0.019545	276	32
19	Mid-peak kWh	14,704	MWh	@	0.015992	235	0.018095	266	31
20	Off-peak kWh	182,038	MWh	@	0.013303	2,422	0.015053	2,740	319
21	Power Factor Adjustment					7		5	(1)
22	Interruptible Credit	332,592	MWh	@	(0.008461)	(2,814)	(0.008461)	(2,814)	-
23	Annual PSCR Factor	332,592	MWh	@	0.009410	3,130	0.009410	3,130	-
24	Total Production					$ 17,677		$ 14,298	$ (3,379)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	206	MWh	@	0.041546	$ 9	0.042201	$ 9	$ 0
26	High-peak kWh	7,015	MWh	@	0.027698	194	0.028134	197	3
27	Mid-peak kWh	7,214	MWh	@	0.024660	178	0.025049	181	3
28	Low-peak kWh	45,458	MWh	@	0.019874	903	0.020187	918	14
29	Off-peak kWh	61,205	MWh	@	0.014865	910	0.015099	924	14
	Winter (Oct. - May)								
30	Critical-peak kWh	647	MWh	@	0.026765	17	0.027186	18	0
31	High-peak kWh	14,105	MWh	@	0.017843	252	0.018124	256	4
32	Mid-peak kWh	14,704	MWh	@	0.016520	243	0.016780	247	4
33	Off-peak kWh	182,038	MWh	@	0.013743	2,502	0.013959	2,541	39
34	Total Transmission					$ 5,208		$ 5,290	$ 82
	Delivery								
35	System Access	64	Bills	@	200.00	$ 13	200.00	$ 13	$ -
36	Maximum kW	771	MW	@	2.37	1,830	2.70	2,079	249
37	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
38	Power Factor Adjustment					1		1	0
39	Distribution	332,592	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,843		$ 2,093	$ 249
41	Total Full Service					$ 24,728		$ 21,681	$ (3,047)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 2 (EIP VL 2)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	27	MWh	@	0.100662	$ 3	0.067632	$ 2	$ (1)
2	High-peak kWh	895	MWh	@	0.067108	60	0.045088	40	(20)
3	Mid-peak kWh	937	MWh	@	0.060183	56	0.040436	38	(19)
4	Low-peak kWh	7,371	MWh	@	0.047832	353	0.032137	237	(116)
5	Off-peak kWh	10,461	MWh	@	0.035024	366	0.023532	246	(120)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	27	MWh	@	0.040805	1	0.046172	1	0
8	High-peak kWh	895	MWh	@	0.027203	24	0.030782	28	3
9	Mid-peak kWh	937	MWh	@	0.024220	23	0.027406	26	3
10	Low-peak kWh	7,371	MWh	@	0.019519	144	0.022087	163	19
11	Off-peak kWh	10,461	MWh	@	0.014600	153	0.016520	173	20
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	79	MWh	@	0.062854	5	0.042230	3	(2)
13	High-peak kWh	1,503	MWh	@	0.041903	63	0.028153	42	(21)
14	Mid-peak kWh	1,737	MWh	@	0.039232	68	0.026359	46	(22)
15	Off-peak kWh	30,227	MWh	@	0.032990	997	0.022165	670	(327)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	79	MWh	@	0.026287	2	0.029745	2	0
18	High-peak kWh	1,503	MWh	@	0.017525	26	0.019830	30	3
19	Mid-peak kWh	1,737	MWh	@	0.016225	28	0.018359	32	4
20	Off-peak kWh	30,227	MWh	@	0.013498	408	0.015273	462	54
21	Power Factor Adjustment					(14)		(11)	3
22	Interruptible Credit	53,237	MWh	@	(0.008461)	(450)	(0.008461)	(450)	-
23	Annual PSCR Factor	53,237	MWh	@	0.009410	501	0.009410	501	-
24	Total Production					$ 2,817		$ 2,280	$ (538)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	27	MWh	@	0.042153	$ 1	0.042817	$ 1	$ 0
26	High-peak kWh	895	MWh	@	0.028102	25	0.028544	26	0
27	Mid-peak kWh	937	MWh	@	0.025021	23	0.025415	24	0
28	Low-peak kWh	7,371	MWh	@	0.020164	149	0.020482	151	2
29	Off-peak kWh	10,461	MWh	@	0.015082	158	0.015320	160	2
	Winter (Oct. - May)								
30	Critical-peak kWh	79	MWh	@	0.027155	2	0.027583	2	0
31	High-peak kWh	1,503	MWh	@	0.018104	27	0.018389	28	0
32	Mid-peak kWh	1,737	MWh	@	0.016761	29	0.017025	30	0
33	Off-peak kWh	30,227	MWh	@	0.013944	421	0.014163	428	7
34	Total Transmission					$ 836		$ 849	$ 13
	Delivery								
35	System Access	82	Bills	@	200.00	$ 16	200.00	$ 16	$ -
36	Maximum kW	373	MW	@	3.61	1,347	3.13	1,166	(180)
37	Substation Ownership	169	MW	@	(1.93)	(326)	(1.93)	(326)	-
38	Power Factor Adjustment					(5)		(4)	1
39	Distribution	53,237	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,032		$ 852	$ (179)
41	Total Full Service					$ 4,685		$ 3,981	$ (704)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 3 (EIP VL 3)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	1	MWh	@	0.101677	$ 0	0.068314	$ 0	$ (0)
2	High-peak kWh	66	MWh	@	0.067784	5	0.045543	3	(1)
3	Mid-peak kWh	104	MWh	@	0.060790	6	0.040843	4	(2)
4	Low-peak kWh	1,569	MWh	@	0.048314	76	0.032461	51	(25)
5	Off-peak kWh	908	MWh	@	0.035378	32	0.023769	22	(11)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	1	MWh	@	0.041452	0	0.046905	0	0
8	High-peak kWh	66	MWh	@	0.027635	2	0.031270	2	0
9	Mid-peak kWh	104	MWh	@	0.024605	3	0.027841	3	0
10	Low-peak kWh	1,569	MWh	@	0.019829	31	0.022438	35	4
11	Off-peak kWh	908	MWh	@	0.014831	13	0.016782	15	2
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	4	MWh	@	0.063488	0	0.042656	0	(0)
13	High-peak kWh	93	MWh	@	0.042325	4	0.028437	3	(1)
14	Mid-peak kWh	119	MWh	@	0.039628	5	0.026625	3	(2)
15	Off-peak kWh	3,871	MWh	@	0.033323	129	0.022389	87	(42)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	4	MWh	@	0.026704	0	0.030217	0	0
18	High-peak kWh	93	MWh	@	0.017803	2	0.020145	2	0
19	Mid-peak kWh	119	MWh	@	0.016483	2	0.018651	2	0
20	Off-peak kWh	3,871	MWh	@	0.013712	53	0.015516	60	7
21	Power Factor Adjustment					(1)		(1)	0
22	Interruptible Credit	6,737	MWh	@	(0.008461)	(57)	(0.008461)	(57)	-
23	Annual PSCR Factor	6,737	MWh	@	0.009410	63	0.009410	63	-
24	Total Production					$ 368		$ 298	$ (70)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	1	MWh	@	0.042822	$ 0	0.043496	$ 0	$ 0
26	High-peak kWh	66	MWh	@	0.028548	2	0.028997	2	0
27	Mid-peak kWh	104	MWh	@	0.025418	3	0.025818	3	0
28	Low-peak kWh	1,569	MWh	@	0.020484	32	0.020807	33	1
29	Off-peak kWh	908	MWh	@	0.015321	14	0.015563	14	0
	Winter (Oct. - May)								
30	Critical-peak kWh	4	MWh	@	0.027586	0	0.028021	0	0
31	High-peak kWh	93	MWh	@	0.018391	2	0.018681	2	0
32	Mid-peak kWh	119	MWh	@	0.017027	2	0.017295	2	0
33	Off-peak kWh	3,871	MWh	@	0.014165	55	0.014388	56	1
34	Total Transmission					$ 109		$ 111	$ 2
	Delivery								
35	System Access	54	Bills	@	200.00	$ 11	200.00	$ 11	$ -
36	Maximum kW	40	MW	@	6.68	267	5.82	232	(34)
37	Power Factor Adjustment					(1)		(0)	0
38	Distribution	6,737	MWh	@	-	-	-	-	-
39	Total Delivery					$ 277		$ 243	$ (34)
40	Total Full Service					$ 754		$ 652	$ (103)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Metered Lighting (GML)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c) Present Rate $/unit	(d) Present Revenue $000	(e) Proposed Rate $/unit	(f) Proposed Revenue $000	(g) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
1	Secondary All kWh	10,328	MWh	@	0.034716	$ 359	0.026629	$ 275	$ (84)
2	Primary All kWh	448	MWh	@	0.017037	8	0.013068	6	(2)
3	Annual PSCR Factor	10,776	MWh	@	0.009410	101	0.009410	101	-
4	Total Production					$ 468		$ 382	$ (85)
	Transmission								
5	Secondary All kWh	10,328	MWh	@	0.010556	109	0.010722	111	2
6	Primary All kWh	448	MWh	@	0.005180	2	0.005262	2	0
7	Total Transmission	10,776				111		113	2
	Delivery								
	Secondary								
8	System Access	4,489	Bills	@	10.00	$ 45	10.00	$ 45	$ -
9	Distribution	10,328	MWh	@	0.118564	1,225	0.119676	1,236	11
	Primary								
10	System Access	297	Bills	@	20.00	$ 6	20.00	$ 6	$ -
11	Distribution	448	MWh	@	0.090355	41	0.091203	41	0
12	Total Delivery					$ 1,316		$ 1,328	$ 12
13	Total Full Service					$ 1,895		$ 1,823	$ (72)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Universal Unmetered Light (UUL)

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Witness: LMConnolly
Date: June 2026

Line		Billing Determinants							Present					Proposed					
						Customer	Company		Customer Owned		Company Owned			Customer Owned		Company Owned			Net Increase
No.	Description	Customer	Company	Units	Watts	MWh	MWh		Production	Delivery	Production	Delivery	Revenue	Production	Delivery	Production	Delivery	Revenue	/ (Decrease)
									$/Light	$/Light	$/Light	$/Light	$000	$/Light	$/Light	$/Light	$/Light	$000	$000
1	15 - 24 Watts	12	-	Lights	20	0	-	@	0.28	7.29	0.28	10.29	$ 0	0.23	7.45	0.23	10.45	$ 0	$ 0
2	25 - 34 Watts	-	64,500	Lights	30	-	666	@	0.43	8.07	0.43	11.07	742	0.35	8.25	0.35	11.25	748	6
3	35 - 44 Watts	1,524	412,356	Lights	40	21	5,701	@	0.57	8.85	0.57	11.85	5,136	0.46	9.05	0.46	12.05	5,173	37
4	45 - 54 Watts	1,308	865,773	Lights	50	23	15,000	@	0.72	9.63	0.72	12.63	11,572	0.58	9.84	0.58	12.84	11,632	61
5	55 - 64 Watts	1,092	7,056	Lights	60	23	147	@	0.86	10.41	0.86	13.41	113	0.70	10.64	0.70	13.64	114	1
6	65 - 74 Watts	312	129,516	Lights	70	8	3,150	@	1.01	11.19	1.01	14.19	1,972	0.82	11.44	0.82	14.44	1,980	8
7	75 - 84 Watts	72	34,020	Lights	80	2	947	@	1.15	11.97	1.15	14.97	549	0.93	12.23	0.93	15.23	551	1
8	85 - 94 Watts	-	98,178	Lights	90	-	3,075	@	1.29	12.75	1.29	15.75	1,673	1.05	13.03	1.05	16.03	1,677	4
9	95 - 104 Watts	-	180	Lights	100	-	6	@	1.44	13.53	1.44	16.53	3	1.17	13.82	1.17	16.82	3	0
10	105 - 114 Watts	-	7,044	Lights	110	-	270	@	1.58	14.31	1.58	17.31	133	1.29	14.62	1.29	17.62	133	0
11	115 - 124 Watts	804	364,751	Lights	120	34	15,256	@	1.73	15.09	1.73	18.09	7,243	1.40	15.42	1.40	18.42	7,243	-
12	125 - 134 Watts	-	320	Lights	130	-	15	@	1.87	15.86	1.87	18.86	7	1.52	16.21	1.52	19.21	7	-
13	135 - 144 Watts	-	924	Lights	140	-	45	@	2.02	16.64	2.02	19.64	20	1.64	17.01	1.64	20.01	20	(0)
14	145 - 154 Watts	-	3,996	Lights	150	-	209	@	2.16	17.42	2.16	20.42	90	1.76	17.81	1.76	20.81	90	(0)
15	155 - 164 Watts	-	52	Lights	160	-	3	@	2.31	18.20	2.31	21.20	1	1.87	18.60	1.87	21.60	1	(0)
16	165 - 174 Watts	1,404	51,182	Lights	170	83	3,036	@	2.45	18.98	2.45	21.98	1,280	1.99	19.40	1.99	22.40	1,278	(2)
17	175 - 184 Watts	-	-	Lights	180	-	-	@	2.60	19.76	2.60	22.76	-	2.11	20.20	2.11	23.20	-	-
18	185 - 194 Watts	-	156	Lights	190	-	10	@	2.74	20.54	2.74	23.54	4	2.23	20.99	2.23	23.99	4	(0)
19	195 - 204 Watts	-	60	Lights	200	-	4	@	2.89	21.32	2.89	24.32	2	2.35	21.79	2.35	24.79	2	(0)
20	205 - 214 Watts	504	12,740	Lights	210	37	934	@	3.03	22.10	3.03	25.10	371	2.46	22.59	2.46	25.59	370	(1)
21	215 - 224 Watts	-	28	Lights	220	-	2	@	3.17	22.88	3.17	25.88	1	2.58	23.38	2.58	26.38	1	(0)
22	225 - 234 Watts	-	-	Lights	230	-	-	@	3.32	23.66	3.32	26.66	-	2.70	24.18	2.70	27.18	-	-
23	235 - 244 Watts	-	-	Lights	240	-	-	@	3.46	24.44	3.46	27.44	-	2.82	24.98	2.82	27.98	-	-
24	245 - 254 Watts	60	432	Lights	250	5	38	@	3.61	25.22	3.61	28.22	15	2.93	25.77	2.93	28.77	15	(0)
25	255 - 264 Watts	-	-	Lights	260	-	-	@	3.75	26.00	3.75	29.00	-	3.05	26.57	3.05	29.57	-	-
26	265 - 274 Watts	-	-	Lights	270	-	-	@	3.90	26.78	3.90	29.78	-	3.17	27.36	3.17	30.36	-	-
27	275 - 284 Watts	396	3,949	Lights	280	39	386	@	4.04	27.56	4.04	30.56	149	3.29	28.16	3.29	31.16	148	(1)
28	285 - 294 Watts	12	1,292	Lights	290	1	131	@	4.19	28.34	4.19	31.34	46	3.40	28.96	3.40	31.96	46	(0)
29	295 - 304 Watts	-	-	Lights	300	-	-	@	4.33	29.12	4.33	32.12	-	3.52	29.75	3.52	32.75	-	-
30	305 - 314 Watts	108	-	Lights	310	12	-	@	4.48	29.90	4.48	32.90	4	3.64	30.55	3.64	33.55	4	(0)
31	315 - 324 Watts	540	29,081	Lights	320	60	3,252	@	4.62	30.68	4.62	33.68	1,133	3.76	31.35	3.76	34.35	1,127	(6)
32	325 - 334 Watts	-	-	Lights	330	-	-	@	4.77	31.45	4.77	34.45	-	3.87	32.14	3.87	35.14	-	-
33	335 - 344 Watts	-	-	Lights	340	-	-	@	4.91	32.23	4.91	35.23	-	3.99	32.94	3.99	35.94	-	-
34	345 - 354 Watts	-	-	Lights	350	-	-	@	5.05	33.01	5.05	36.01	-	4.11	33.74	4.11	36.74	-	-
35	355 - 364 Watts	-	-	Lights	360	-	-	@	5.20	33.79	5.20	36.79	-	4.23	34.53	4.23	37.53	-	-
36	365 - 374 Watts	-	-	Lights	370	-	-	@	5.34	34.57	5.34	37.57	-	4.34	35.33	4.34	38.33	-	-
37	375 - 384 Watts	-	-	Lights	380	-	-	@	5.49	35.35	5.49	38.35	-	4.46	36.13	4.46	39.13	-	-
38	385 - 394 Watts	-	-	Lights	390	-	-	@	5.63	36.13	5.63	39.13	-	4.58	36.92	4.58	39.92	-	-
39	395 - 404 Watts	-	12	Lights	400	-	2	@	5.78	36.91	5.78	39.91	1	4.70	37.72	4.70	40.72	1	(0)
40	405 - 414 Watts	24	24	Lights	410	3	3	@	5.92	37.69	5.92	40.69	2	4.81	38.52	4.81	41.52	2	(0)
41	415 - 424 Watts	-	-	Lights	420	-	-	@	6.07	38.47	6.07	41.47	-	4.93	39.31	4.93	42.31	-	-
42	425 - 434 Watts	-	-	Lights	430	-	-	@	6.21	39.25	6.21	42.25	-	5.05	40.11	5.05	43.11	-	-
43	435 - 444 Watts	-	-	Lights	440	-	-	@	6.36	40.03	6.36	43.03	-	5.17	40.90	5.17	43.90	-	-
44	445 - 454 Watts	-	-	Lights	450	-	-	@	6.50	40.81	6.50	43.81	-	5.28	41.70	5.28	44.70	-	-
45	455 - 464 Watts	888	1,460	Lights	460	143	235	@	6.65	41.59	6.65	44.59	118	5.40	42.50	5.40	45.50	117	(1)
46	465 - 474 Watts	-	-	Lights	470	-	-	@	6.79	42.37	6.79	45.37	-	5.52	43.29	5.52	46.29	-	-
47	475 - 484 Watts	180	9,489	Lights	480	30	1,593	@	6.94	43.15	6.94	46.15	513	5.64	44.09	5.64	47.09	509	(3)
48	Conversion Credit	-	129,840	Lights								(7.72)	(1,002)				(7.72)	(1,002)	-
49	Annual PSCR Factor	9,240	2,098,571	Lights		524	54,116		0.009410		0.009410		514	0.009410		0.009410		514	-
50	Total Unmetered LED	9,240	2,098,571	Lights		524	54,116						$ 32,405					$ 32,509	$ 104

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Unmetered Service (GU)

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
Line		Billing Determinants			Present		Proposed		Net Increase
No.	Description	Quantity	Units		Rate	Revenue	Rate	Revenue	/ (Decrease)
					$/unit	$000	$/unit	$000	$000
	FULL SERVICE								
	Production								
1	Non-capacity All kWh	99,352	MWh	@	0.037706	$ 3,746	0.025214	$ 2,505	$ (1,241)
2	Capacity All kWh	99,352	MWh	@	0.015927	1,582	0.018005	1,789	206
3	Annual PSCR Factor	99,352	MWh	@	0.009410	935	0.009410	935	-
4	Total Production					$ 6,264		$ 5,229	$ (1,035)
	Transmission								
5	All kWh	99,352	MWh	@	0.015085	1,499	0.015322	1,522	24
	Delivery								
6	System Access	5,578	Bills	@	2.00	$ 11	2.00	$ 11	$ -
7	Distribution	99,352	MWh	@	0.034452	3,423	0.034831	3,461	38
8	Total Delivery					$ 3,434		$ 3,472	$ 38
9	Total Full Service					$ 11,196		$ 10,223	$ (973)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Large Self-generation (GSG-2)

Case No.: U-22070
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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	STANDBY SERVICE								
	Production								
	Voltage Level 1								
1	On-peak kW-day	108	MW	@	11.57	$ 1,254	11.57	$ 1,254	$ -
2	All kWh	77,349	MWh	@	0.046132	3,568	0.046132	3,568	-
	Voltage Level 2								
3	On-peak kW-day	223	MW	@	11.73	2,613	11.73	2,613	-
4	All kWh	77,337	MWh	@	0.048126	3,722	0.048126	3,722	-
	Voltage Level 3								
5	On-peak kW-day	55	MW	@	11.91	650	11.91	650	-
6	All kWh	18,615	MWh	@	0.047120	877	0.047120	877	-
7	Power Factor Adjustment					261		261	-
8	Total Production					$ 12,946		$ 12,946	$ -
	Transmission								
	Voltage Level 1								
9	On-peak kW-day	108	MW	@	3.05	$ 330	3.05	$ 330	$ -
	Voltage Level 2								
10	On-peak kW-day	223	MW	@	3.09	688	3.09	688	-
	Voltage Level 3								
11	On-peak kW-day	55	MW	@	3.14	171	3.14	171	-
12	Total Transmission					$ 1,190		$ 1,190	$ -
	Delivery								
	System Access								
	Voltage Level 1								
13	Standby	64	Bills	@	100.00	$ 6	100.00	$ 6	$ -
14	Supplemental	-	Bills	@	100.00	-	100.00	-	-
15	Maximum kW	889	MW	@	2.37	2,110	2.70	2,397	287
16	Interconnect	355	MW	@	(2.37)	(842)	(2.70)	(957)	(115)
17	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
	Voltage Level 2								
18	Standby	94	Bills	@	100.00	$ 9	100.00	$ 9	$ -
19	Supplemental	-	Bills	@	100.00	-	100.00	-	-
20	Maximum kW	610	MW	@	3.61	2,203	3.13	1,908	(295)
21	Substation Ownership	288	MW	@	(1.93)	(555)	(1.93)	(555)	-
	Voltage Level 3								
22	Standby	13	Bills	@	100.00	$ 1	100.00	$ 1	$ -
23	Supplemental	-	Bills	@	100.00	-	100.00	-	-
24	Maximum kW	62	MW	@	6.68	412	5.82	359	(53)
25	Power Factor Adjustment					63		58	(5)
26	Total Delivery					$ 3,408		$ 3,228	$ (180)
27	Total Standby Service					$ 17,543		$ 17,364	$ (180)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response (DR) Surcharge

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	ID	(b) Program plus Cust. Credits (1)	(c) Financial Incentive (1)	(d) Reconciled Balance (1)	(e) Total	(f) Units
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	DR0001	0.001707	-	-	0.001707	per kWh
2	Smart Hours RSH	DR0001	0.001707	-	-	0.001707	per kWh
3	Night Time Savers RPM	DR0001	0.001707	-	-	0.001707	per kWh
4	Non-Transmitting Meters RSM	DR0001	0.001707	-	-	0.001707	per kWh
	Secondary Class						
5	Energy-only GS	DR0002	0.001552	-	-	0.001552	per kWh
6	Time-of-Use GSTU	DR0003	0.001552	-	-	0.001552	per kWh
7	Demand GSD	DR0004	0.52	-	-	0.52	per Peak kW
	Primary Class						
	Energy-only GP						
8	Voltage Level 1	DR0005	0.001313	-	-	0.001313	per kWh
9	Voltage Level 2	DR0006	0.001328	-	-	0.001328	per kWh
10	Voltage Level 3	DR0007	0.001342	-	-	0.001342	per kWh
	Demand GPD						
11	Voltage Level 1	DR0008	0.63	-	-	0.63	per On-Peak kW
12	Voltage Level 2	DR0009	0.64	-	-	0.64	per On-Peak kW
13	Voltage Level 3	DR0010	0.65	-	-	0.65	per On-Peak kW
	Time-of-Use GPTU						
14	Voltage Level 1	DR0011	0.001188	-	-	0.001188	per kWh
15	Voltage Level 2	DR0012	0.001202	-	-	0.001202	per kWh
16	Voltage Level 3	DR0013	0.001214	-	-	0.001214	per kWh
	Energy Intensive EIP						
17	Voltage Level 1	DR0014	0.000959	-	-	0.000959	per kWh
18	Voltage Level 2	DR0015	0.000970	-	-	0.000970	per kWh
19	Voltage Level 3	DR0016	0.000980	-	-	0.000980	per kWh
	Lighting & Unmetered Class						
20	Metered Lighting GML	DR0017	0.000372	-	-	0.000372	per kWh
21	Universal Unmetered Lighting UUL	DR0018	0.000347	-	-	0.000347	per kWh
22	Unmetered GU	DR0019	0.001011	-	-	0.001011	per kWh
	ROA SERVICE						
	Secondary Class						
23	Energy-only GS		NA	NA	NA	NA	
24	Demand GSD		NA	NA	NA	NA	
	Primary Class						
	Energy-only GP						
25	Voltage Level 1		NA	NA	NA	NA	
26	Voltage Level 2		NA	NA	NA	NA	
27	Voltage Level 3		NA	NA	NA	NA	
	Demand GPD						
28	Voltage Level 1		NA	NA	NA	NA	
29	Voltage Level 2		NA	NA	NA	NA	
30	Voltage Level 3		NA	NA	NA	NA	

(1) WP-LMC-19

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Rate Case (ERC) Deferral Surcharge

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) ERC Deferral [1] ($000)	(d) ERC Deferral Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 15,413	0.001215
	Secondary Class			
2	Energy-only GS	4,114,839	3,839	0.000933
3	Time-of-Use GSTU	84,563	79	0.000933
4	Demand GSD	2,979,606	2,139	0.000718
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	0	0.000031
6	Voltage Level 2	31,259	6	0.000177
7	Voltage Level 3	632,239	193	0.000305
	Demand GPD			
8	Voltage Level 1	9,051,540	199	0.000022
9	Voltage Level 2	1,453,040	183	0.000126
10	Voltage Level 3	2,414,780	522	0.000216
	Time-of-Use GPTU			
11	Voltage Level 1	464,518	10	0.000022
12	Voltage Level 2	496,642	63	0.000126
13	Voltage Level 3	3,312,240	715	0.000216
	Energy Intensive EIP			
14	Voltage Level 1	332,592	7	0.000022
15	Voltage Level 2	53,237	7	0.000126
16	Voltage Level 3	6,737	1	0.000216
	Lighting & Unmetered Class			
17	Metered Lighting GML	10,776	15	0.001397
18	Universal Unmetered Lighting UUL	54,640	342	0.006258
19	Unmetered GU	99,352	40	0.000399
	Self-generation Class			
20	Large Self-generation GSG-2			
21	Voltage Level 1	77,349	2	0.000022
22	Voltage Level 2	77,337	10	0.000126
23	Voltage Level 3	18,615	4	0.000216
24	Total Full Service		$ 23,788	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) ERC Deferral [1] ($000)	(h) ERC Deferral Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001215
	Secondary Class			
2	Energy-only GS	18,702	17	0.000933
3	Time-of-Use GSTU	-	-	0.000933
4	Demand GSD	174,288	125	0.000718
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000031
6	Voltage Level 2	1,783	0	0.000177
7	Voltage Level 3	70,285	21	0.000305
	Demand GPD			
8	Voltage Level 1	1,270,576	28	0.000022
9	Voltage Level 2	1,080,207	136	0.000126
10	Voltage Level 3	953,091	206	0.000216
11	Total ROA Service		$ 534	
12	Total Surcharge Revenue Collected		$ 24,323	
13	Rounding		5	
14	Total Surcharge Revenue Target		$ 24,327	

(1) A-89 (EAD-5), line 12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 1 - 12 months ending April 30, 2027

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue (1) ($000)	(d) IRM Surcharge ($ / kWh)	Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue (1) ($000)	(h) IRM Surcharge ($ / kWh)
	FULL SERVICE					**ROA SERVICE**			
1	Residential Class	12,685,410	$ 8,829	0.000696	1	Residential Class	-	$ -	0.000696
	Secondary Class					Secondary Class			
2	Energy-only GS	4,114,839	2,197	0.000534	2	Energy-only GS	18,702	10	0.000534
3	Time-of-Use GSTU	84,563	45	0.000534	3	Time-of-Use GSTU	-	-	0.000534
4	Demand GSD	2,979,606	1,225	0.000411	4	Demand GSD	174,288	72	0.000411
	Primary Class					Primary Class			
	Energy-only GP					Energy-only GP			
5	Voltage Level 1	3,454	0	0.000018	5	Voltage Level 1	-	-	0.000018
6	Voltage Level 2	31,259	3	0.000103	6	Voltage Level 2	1,783	0	0.000103
7	Voltage Level 3	632,239	112	0.000177	7	Voltage Level 3	70,285	12	0.000177
	Demand GPD					Demand GPD			
8	Voltage Level 1	9,051,540	118	0.000013	8	Voltage Level 1	1,270,576	17	0.000013
9	Voltage Level 2	1,453,040	108	0.000074	9	Voltage Level 2	1,080,207	80	0.000074
10	Voltage Level 3	2,414,780	309	0.000128	10	Voltage Level 3	953,091	122	0.000128
	Time-of-Use GPTU								
11	Voltage Level 1	464,518	6	0.000013	11	Total ROA Service		$ 313	
12	Voltage Level 2	496,642	37	0.000074					
13	Voltage Level 3	3,312,240	424	0.000128	12	Total Surcharge Revenue Collected		$ 13,970	
	Energy Intensive EIP				13	Rounding		(43)	
14	Voltage Level 1	332,592	4	0.000013	14	Total Surcharge Revenue Target		$ 13,927	
15	Voltage Level 2	53,237	4	0.000074					
16	Voltage Level 3	6,737	1	0.000128					
	Lighting & Unmetered Class								
17	Metered Lighting GML	10,776	9	0.000800					
18	Universal Unmetered Lighting UUL	54,640	196	0.003583					
19	Unmetered GU	99,352	23	0.000229					
	Self-generation Class								
20	Large Self-generation GSG-2								
21	Voltage Level 1	77,349	1	0.000013					
22	Voltage Level 2	77,337	6	0.000074					
23	Voltage Level 3	18,615	2	0.000128					
24	Total Full Service		$ 13,658						

(1) A-89 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 2 - 12 months ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-65 (LMC-2)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue (1) ($000)	(d) IRM Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 16,212	0.001278
	Secondary Class			
2	Energy-only GS	4,114,839	4,041	0.000982
3	Time-of-Use GSTU	84,563	83	0.000982
4	Demand GSD	2,979,606	2,253	0.000756
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	0	0.000033
6	Voltage Level 2	31,259	10	0.000325
7	Voltage Level 3	632,239	205	0.000325
	Demand GPD			
8	Voltage Level 1	9,051,540	181	0.000020
9	Voltage Level 2	1,453,040	286	0.000197
10	Voltage Level 3	2,414,780	476	0.000197
	Time-of-Use GPTU			
11	Voltage Level 1	464,518	9	0.000020
12	Voltage Level 2	496,642	98	0.000197
13	Voltage Level 3	3,312,240	653	0.000197
	Energy Intensive EIP			
14	Voltage Level 1	332,592	7	0.000020
15	Voltage Level 2	53,237	10	0.000197
16	Voltage Level 3	6,737	1	0.000197
	Lighting & Unmetered Class			
17	Metered Lighting GML	10,776	16	0.001470
18	Universal Unmetered Lighting UUL	54,640	360	0.006580
19	Unmetered GU	99,352	42	0.000420
	Self-generation Class			
20	Large Self-generation GSG-2			
21	Voltage Level 1	77,349	2	0.000020
22	Voltage Level 2	77,337	15	0.000197
23	Voltage Level 3	18,615	4	0.000197
24	Total Full Service		$ 24,963	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue (1) ($000)	(h) IRM Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001278
	Secondary Class			
2	Energy-only GS	18,702	18	0.000982
3	Time-of-Use GSTU	-	-	0.000982
4	Demand GSD	174,288	132	0.000756
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000033
6	Voltage Level 2	1,783	1	0.000325
7	Voltage Level 3	70,285	23	0.000325
	Demand GPD			
8	Voltage Level 1	1,270,576	25	0.000020
9	Voltage Level 2	1,080,207	213	0.000197
10	Voltage Level 3	953,091	188	0.000197
11	Total ROA Service		$ 600	
12	Total Surcharge Revenue Collected		$ 25,562	
13	Rounding		34	
14	Total Surcharge Revenue Target		$ 25,597	

(1) A-89 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Total Revenues

Proposal 2

U-21870 Final Order Model

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Exhibit No.: A-66 (LMC-3)
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Line No.	(a) Description	(b) Customers	(c) Sales	(d) Revenue Present	(e) Revenue Proposed	(f) Net Increase / (Decrease) Revenue	(g) Net Increase / (Decrease) Percent
		Mthly	MWh	$000	$000	$000	%
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	1,628,594	12,230,766	$ 2,530,673	$ 2,427,340	$ (103,334)	(4.1)
2	Smart Hours RSH	24,351	177,999	36,984	35,478	(1,506)	(4.1)
3	Night Time Savers RPM	16,879	168,382	34,132	32,750	(1,382)	(4.0)
4	Non-Transmitting Meters RSM	10,973	108,263	23,269	22,373	(897)	(3.9)
5	Total Residential Class	1,680,798	12,685,410	$ 2,625,059	$ 2,517,940	$ (107,119)	(4.1)
	Secondary Class						
6	Energy-only GS	204,973	4,114,839	$ 742,820	$ 708,365	$ (34,456)	(4.6)
7	Time-of-Use GSTU	1,891	84,563	15,240	14,467	(773)	(5.1)
8	Demand GSD	20,152	2,979,606	467,203	441,145	(26,058)	(5.6)
9	Total Secondary	227,015	7,179,008	$ 1,225,264	$ 1,163,977	$ (61,287)	(5.0)
	Primary Class						
10	Energy-only GP	1,360	666,952	$ 78,703	$ 72,775	$ (5,928)	(7.5)
11	Demand GPD	855	5,035,360	455,727	409,450	(46,277)	(10.2)
12	Large Load	1	7,884,000	-	531,955	531,955	NA
13	Time-of-Use GPTU	1,517	4,273,401	448,037	408,252	(39,784)	(8.9)
14	Energy Intensive EIP	17	392,565	30,168	25,533	(4,635)	(15.4)
15	Total Primary	3,749	18,252,279	$ 1,012,633	$ 1,447,965	$ 435,332	43.0
	Lighting & Unmetered Class						
16	Metered Lighting GML	399	10,776	$ 1,895	$ 1,836	$ (59)	(3.1)
17	Universal Unmetered Lighting UUL	4,696	54,640	32,405	32,724	319	1.0
18	Unmetered GU	465	99,352	11,196	10,346	(850)	(7.6)
19	Total Lighting & Unmetered	5,560	164,769	$ 45,496	$ 44,905	$ (590)	(1.3)
	Self-generation Class						
20	Small Self-generation GSG-1	-	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	14	173,301	17,543	16,787	(757)	(4.3)
22	Total Self-generation	14	173,301	$ 17,543	$ 16,787	$ (757)	(4.3)
23	Total Full Service	1,917,136	38,454,766	$ 4,925,995	$ 5,191,574	$ 265,579	5.4
	ROA SERVICE						
	Secondary Class						
24	Energy-only GS	85	18,702	$ 1,307	$ 1,344	$ 37	2.8
25	Demand GSD	472	174,288	10,522	10,744	222	2.1
26	Total Secondary	556	192,989	$ 11,829	$ 12,089	$ 259	2.2
	Primary Class						
27	Energy-only GP	60	72,068	$ 1,792	$ 1,848	$ 56	3.1
28	Demand GPD	356	3,303,873	30,936	28,126	(2,810)	(9.1)
29	Total Primary	417	3,375,942	$ 32,727	$ 29,974	$ (2,754)	(8.4)
30	Total ROA Service	973	3,568,931	$ 44,557	$ 42,062	$ (2,494)	(5.6)
31	Total Jurisdictional Service	1,918,109	42,023,697	$ 4,970,552	$ 5,233,636	$ 263,085	5.3
32	Plus: Rounding			-	340	(340)	
33	Total Jurisdictional Revenues			$ 4,970,552	$ 5,233,977	$ 263,425	5.3
34	Less: PSCR Factor Revenues			299,823	374,011	74,188	
35	Less: DR Surcharge			-	51,821	51,821	
36	Less: IRM Surcharge			-	13,927	13,927	
37	Total Jurisdictional Base Revenues			$ 4,670,729	$ 4,794,217	$ 123,488	2.6
38	Total Jurisdictional Revenues			4,970,552	5,233,977	263,425	5.3
39	Plus: ERC Deferral Surcharge			-	24,111	24,111	
40	Total Jurisdictional Revenues Requested			$ 4,970,552	$ 5,258,088	$ 287,536	5.8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Production & Transmission Revenues

Proposal 2

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Sales	Revenue Present	Revenue Proposed	Net Increase / (Decrease) Revenue	Net Increase / (Decrease) Percent
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,230,766	$ 1,259,128	$ 1,132,129	$ (126,999)	(10.1)
2	Smart Hours RSH	177,999	18,333	16,482	(1,851)	(10.1)
3	Night Time Savers RPM	168,382	17,006	15,298	(1,708)	(10.0)
4	Non-Transmitting Meters RSM	108,263	11,022	9,916	(1,106)	(10.0)
5	Total Residential Class	12,685,410	$ 1,305,488	$ 1,173,825	$ (131,663)	(10.1)
	Secondary Class					
6	Energy-only GS	4,114,839	$ 408,019	$ 365,611	$ (42,408)	(10.4)
7	Time-of-Use GSTU	84,563	8,915	7,978	(936)	(10.5)
8	Demand GSD	2,979,606	279,797	250,017	(29,780)	(10.6)
9	Total Secondary	7,179,008	$ 696,731	$ 623,607	$ (73,124)	(10.5)
	Primary Class					
10	Energy-only GP	666,952	$ 61,147	$ 54,739	$ (6,408)	(10.5)
11	Demand GPD	5,035,360	397,720	353,620	(44,100)	(11.1)
12	Large Load	7,884,000	-	505,541	505,541	NA
13	Time-of-Use GPTU	4,273,401	367,811	327,685	(40,126)	(10.9)
14	Energy Intensive EIP	392,565	27,016	23,504	(3,512)	(13.0)
15	Total Primary	18,252,279	$ 853,693	$ 1,265,088	$ 411,395	48.2
	Lighting & Unmetered Class					
16	Metered Lighting GML	10,776	$ 579	$ 499	$ (80)	(13.7)
17	Universal Unmetered Lighting UUL	54,640	2,776	2,363	(413)	(14.9)
18	Unmetered GU	99,352	7,762	6,852	(911)	(11.7)
19	Total Lighting & Unmetered	164,769	$ 11,117	$ 9,714	$ (1,403)	(12.6)
	Self-generation Class					
20	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	173,301	14,136	14,136	-	-
22	Total Self-generation	173,301	$ 14,136	$ 14,136	$ -	-
23	Total Full Service	38,454,766	$ 2,881,165	$ 3,086,370	$ 205,205	7.1
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	-	$ -	$ -	$ -	NA
25	Demand GSD	-	-	-	-	NA
26	Total Secondary	-	$ -	$ -	$ -	NA
	Primary Class					
27	Energy-only GP	-	$ -	$ -	$ -	NA
28	Demand GPD	-	-	-	-	NA
29	Total Primary	-	$ -	$ -	$ -	NA
30	Total ROA Service	-	$ -	$ -	$ -	NA
31	Total Jurisdictional Service	38,454,766	$ 2,881,165	$ 3,086,370	$ 205,205	7.1
32	Plus: Rounding		-	7,466	7,466	
33	Total Jurisdictional Base Revenues		$ 2,881,165	$ 3,093,836	$ 212,670	7.4
34	Less: PSCR Factor Revenues		299,823	374,011	74,188	
35	Less: DR Surcharge		-	51,821	51,821	
36	Less: IRM Surcharge		-	-	-	
37	Total Jurisdictional Base Revenues		$ 2,581,342	$ 2,668,003	$ 86,660	3.4
38	Total Jurisdictional Revenues		2,881,165	3,093,836	212,670	7.4
39	Plus: ERC Deferral Surcharge		-	-	-	
40	Total Jurisdictional Revenues Requested		$ 2,881,165	$ 3,093,836	$ 212,670	7.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Delivery Revenues

Proposal 2

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Sales	(c) Revenue Present	(d) Revenue Proposed	(e) Net Increase / (Decrease) Revenue	(f) Net Increase / (Decrease) Percent
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,230,766	$ 1,271,545	$ 1,295,210	$ 23,665	1.9
2	Smart Hours RSH	177,999	18,652	18,996	344	1.8
3	Night Time Savers RPM	168,382	17,126	17,452	326	1.9
4	Non-Transmitting Meters RSM	108,263	12,248	12,457	209	1.7
5	Total Residential Class	12,685,410	$ 1,319,571	$ 1,344,115	$ 24,545	1.9
	Secondary Class					
6	Energy-only GS	4,114,839	$ 334,801	$ 342,754	$ 7,953	2.4
7	Time-of-Use GSTU	84,563	6,325	6,488	163	2.6
8	Demand GSD	2,979,606	187,406	191,128	3,722	2.0
9	Total Secondary	7,179,008	$ 528,533	$ 540,370	$ 11,838	2.2
	Primary Class					
10	Energy-only GP	666,952	$ 17,556	$ 18,036	$ 480	2.7
11	Demand GPD	5,035,360	58,006	55,830	(2,177)	(3.8)
12	Large Load	7,884,000	-	18,954	18,954	NA
13	Time-of-Use GPTU	4,273,401	80,226	80,567	341	0.4
14	Energy Intensive EIP	392,565	3,152	2,029	(1,123)	(35.6)
15	Total Primary	18,252,279	$ 158,940	$ 175,416	$ 16,476	10.4
	Lighting & Unmetered Class					
16	Metered Lighting GML	10,776	$ 1,316	$ 1,336	$ 20	1.6
17	Universal Unmetered Lighting UUL	54,640	29,629	30,360	731	2.5
18	Unmetered GU	99,352	3,434	3,494	60	1.8
19	Total Lighting & Unmetered	164,769	$ 34,379	$ 35,191	$ 812	2.4
	Self-generation Class					
20	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	173,301	3,408	2,651	(757)	(22.2)
22	Total Self-generation	173,301	$ 3,408	$ 2,651	$ (757)	(22.2)
23	Total Full Service	38,454,766	$ 2,044,829	$ 2,097,743	$ 52,914	2.6
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	18,702	$ 1,307	$ 1,344	$ 37	2.8
25	Demand GSD	174,288	10,522	10,744	222	2.1
26	Total Secondary	192,989	$ 11,829	$ 12,089	$ 259	2.2
	Primary Class					
27	Energy-only GP	72,068	$ 1,792	$ 1,848	$ 56	3.1
28	Demand GPD	3,303,873	30,936	28,126	(2,810)	(9.1)
29	Total Primary	3,375,942	$ 32,727	$ 29,974	$ (2,754)	(8.4)
30	Total ROA Service	3,568,931	$ 44,557	$ 42,062	$ (2,494)	(5.6)
31	Total Jurisdictional Service	42,023,697	$ 2,089,386	$ 2,139,805	$ 50,419	2.4
32	Plus: Rounding		-	336	336	
33	Total Jurisdictional Base Revenues		$ 2,089,386	$ 2,140,141	$ 50,755	2.4
34	Less: PSCR Factor Revenues		-	-	-	
35	Less: DR Surcharge		-	-	-	
36	Less: IRM Surcharge		-	13,927	13,927	
37	Total Jurisdictional Base Revenues		$ 2,089,386	$ 2,126,214	$ 36,828	1.8
38	Total Jurisdictional Revenues		2,089,386	2,140,141	50,755	2.4
39	Plus: ERC Deferral Surcharge		-	24,111	24,111	
40	Total Jurisdictional Revenues Requested		$ 2,089,386	$ 2,164,252	$ 74,866	3.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Rate Design Targets
($000)

Proposal 2

U-21870 Final Order Model

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
Page: 4 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Jurisdictional	(c) Residential	(d) Secondary Class GS	(e) Secondary Class GSD	(f) Primary Class GP	(g) Primary Class GPD	(h) Primary Class LL	(i) Primary Class GPTU	(j) Primary Class EIP	(k) Lighting & Unmetered Class GML	(l) Lighting & Unmetered Class UUL	(m) Lighting & Unmetered Class GU	(n) Self Gen. Class GSG-1	(o) Self Gen. Class GSG-2	Source
	Production															
1	Capacity (SRM)	$ 1,105,401	$ 488,807	$ 143,402	$ 91,125	$ 19,012	$ 106,844	$ 138,149	$ 106,019	$ 7,036	$ 8	$ -	$ 1,868	$ -	$ 3,131	
	Capacity Adjustments [1]															
2	DR Revenue Requirement	(43,454)	(18,153)	(5,465)	(3,563)	(750)	(4,512)	(6,256)	(4,335)	(316)	(3)	(16)	(84)	-	-	WP-LMC-32
3	Self Generation	-	1,232	361	230	48	269	348	267	18	0	-	5	-	(2,778)	Alloc. Line 1
4	Total Adjustments	(43,454)	(16,921)	(5,103)	(3,334)	(702)	(4,242)	(5,908)	(4,068)	(299)	(3)	(16)	(79)	-	(2,778)	
5	Capacity (SRM) Design Target	$ 1,061,947	$ 471,885	$ 138,299	$ 87,791	$ 18,310	$ 102,602	$ 132,241	$ 101,952	$ 6,737	$ 4	$ (16)	$ 1,789	$ -	$ 353	
6	Energy [2]	$ 855,908	$ 264,268	$ 95,523	$ 69,292	$ 15,670	$ 118,230	$ 187,894	$ 101,363	$ 9,886	$ 280	$ 1,433	$ 2,536	$ -	$ (10,466)	
	Energy Adjustments [1]															
7	Self Generation	-	(3,192)	(1,154)	(837)	(189)	(1,428)	(2,270)	(1,224)	(119)	(3)	(17)	(31)	-	10,466	Alloc. Line 6
8	Total Adjustments	-	(3,192)	(1,154)	(837)	(189)	(1,428)	(2,270)	(1,224)	(119)	(3)	(17)	(31)	-	10,466	
9	Energy Design Target	$ 855,908	$ 261,075	$ 94,369	$ 68,455	$ 15,481	$ 116,802	$ 185,624	$ 100,138	$ 9,767	$ 277	$ 1,416	$ 2,505	$ -	$ -	
10	Total Production	$ 1,917,855	$ 732,961	$ 232,668	$ 156,247	$ 33,790	$ 219,403	$ 317,865	$ 202,090	$ 16,504	$ 281	$ 1,400	$ 4,294	$ -	$ 353	
11	**Transmission**															
12	Transmission	758,515	300,835	94,589	61,931	13,734	83,651	113,129	79,960	6,230	113	434	1,518	-	2,391	
13	Self Generation	-	951	299	196	43	265	358	253	20	0	1	5	-	(2,391)	Alloc. Line 12
14	Transmission Design Target	$ 758,515	$ 301,786	$ 94,888	$ 62,127	$ 13,778	$ 83,915	$ 113,487	$ 80,213	$ 6,250	$ 113	$ 435	$ 1,522	$ -	$ -	
	Delivery															
15	Distribution [3]	$ 1,877,265	$ 1,159,835	$ 308,197	$ 188,863	$ 16,459	$ 82,580	$ 15,270	$ 69,451	$ 1,193	$ 1,240	$ 28,563	$ 3,384	$ -	$ 2,229	
16	Customer	248,945	187,288	35,884	9,078	2,929	5,350	1,126	5,601	112	76	1,324	82	-	95	
17	Subtotal Delivery	2,126,210	1,347,123	344,081	197,941	19,388	87,930	16,396	75,052	1,304	1,316	29,887	3,466	-	2,324	
	Credit Adjustments [4]															
18	Substation Credits	$ -	$ 1,792	$ 476	$ 292	$ (8)	$ (1,400)	$ 24	$ (346)	$ (323)	$ 2	$ 44	$ 5	$ -	$ (558)	WP-LMC-37
19	Life Line Credits	0	(13,629)	3,778	2,343	377	2,207	2,533	2,016	136	10	230	-	-	-	WP-LMC-34
20	Total Adjustments	0	(11,837)	4,254	2,634	370	807	2,557	1,670	(187)	12	274	5	-	(558)	
21	Total Delivery Design Target	$ 2,126,210	$ 1,335,286	$ 348,334	$ 200,576	$ 19,757	$ 88,737	$ 18,954	$ 76,722	$ 1,117	$ 1,328	$ 30,161	$ 3,472	$ -	$ 1,766	
22	Total Rate Design Target	$ 4,802,580	$ 2,370,033	$ 675,890	$ 418,949	$ 67,325	$ 392,056	$ 450,306	$ 359,025	$ 23,871	$ 1,722	$ 31,996	$ 9,288	$ -	$ 2,119	
23	DR Surcharge	$ 51,821	$ 21,649	$ 6,517	$ 4,249	$ 894	$ 5,380	$ 7,461	$ 5,169	$ 377	$ 4	$ 19	$ 100	$ -	$ -	WP-LMC-44
24	IRM Surcharge	$ 13,931	$ 8,829	$ 2,252	$ 1,296	$ 127	$ 512	$ 339	$ 323	$ 17	$ 9	$ 196	$ 23	$ -	$ 9	A-68 (LMC-7)
25	Total Revenue Requirement	$ 4,868,332	$ 2,400,511	$ 684,660	$ 424,495	$ 68,346	$ 397,948	$ 458,106	$ 364,517	$ 24,266	$ 1,734	$ 32,211	$ 9,411	$ -	$ 2,128	

Notes
(1) Capacity and energy production costs adjusted to capture elements occurring outside the Cost-of-Service Study.
(2) Includes Non-SRM capacity related costs.
(3) Excludes IRM costs recovered through the IRM surcharge.
(4) Credit adjustments approved in Case No. U-21389

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Summer On-peak (RSP)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
Page: 5 of 32
Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	814,657	MWh	@	0.060410	$ 49,214	0.033381	$ 27,194	$ (22,020)
2	Off-peak kWh	3,560,451	MWh	@	0.041347	147,215	0.022847	81,347	(65,868)
	Capacity								
3	On-peak kWh	814,657	MWh	@	0.053506	43,589	0.060335	49,152	5,563
4	Off-peak kWh	3,560,451	MWh	@	0.036622	130,390	0.041296	147,031	16,641
	Winter (Oct. - May)								
5	Non-capacity All kWh	7,855,392	MWh	@	0.033007	259,279	0.018238	143,270	(116,009)
6	Capacity All kWh	7,855,392	MWh	@	0.029234	229,647	0.032965	258,956	29,309
	Provisions								
	Device Cycling								
7	AC Cycling(1)	270,897	Bills	@	(5.00)	(1,354)	(5.00)	(1,354)	-
8	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
9	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
10	Peak Time Rewards	1,016	MWh	@	(0.50)	(508)	(0.50)	(508)	-
	Critical Peak Pricing								
11	Critical-peak Charge	266	MWh	@	1.00	266	1.00	266	-
12	Off-peak Credits	41,754	MWh	@	(0.006373)	(266)	(0.006373)	(266)	-
13	Annual PSCR Factor	12,230,766	MWh	@	0.009410	115,092	0.009410	115,092	-
14	Total Production					$ 972,564		$ 820,180	$ (152,384)
	Transmission								
	Summer (June - Sept.)								
15	On-peak kWh	814,657	MWh	@	0.037988	$ 30,947	0.038586	$ 31,434	$ 487
16	Off-peak kWh	3,560,451	MWh	@	0.026001	92,574	0.026410	94,031	1,458
	Winter (Oct. - May)								
17	All kWh	7,855,392	MWh	@	0.020756	163,043	0.021082	165,611	2,567
18	Total Transmission					$ 286,564		$ 291,077	$ 4,513
	Delivery								
19	System Access	19,543,128	Bills	@	8.00	$ 156,345	8.00	$ 156,345	$ -
20	Distribution	12,230,766	MWh	@	0.093333	1,141,532	0.094572	1,156,684	15,152
	Provisions								
21	Senior Citizen (RSC)	4,444,922	Bills	@	(4.00)	(17,780)	(4.00)	(17,780)	-
22	Low Income Credit (LIAC)	66,396	Bills	@	(42.00)	(2,789)	(42.00)	(2,789)	-
23	Income Assistance (RIA)	720,358	Bills	@	(8.00)	(5,763)	(8.00)	(5,763)	-
24	Total Delivery					$ 1,271,545		$ 1,286,698	$ 15,152
25	Total Full Service					$ 2,530,673		$ 2,397,954	$ (132,719)
	ROA SERVICE								
	Delivery								
26	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
27	Distribution	-	MWh	@	0.093333	-	0.094572	-	-
	Provisions								
28	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
29	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
30	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
31	Total Delivery					$ -		$ -	$ -
32	Total Full & ROA Service					$ 2,530,673		$ 2,397,954	$ (132,719)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Smart Hours (RSH)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
Page: 6 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	11,637	MWh	@	0.060410	$ 703	0.033381	$ 388	$ (315)
2	Off-peak kWh	54,082	MWh	@	0.041347	2,236	0.022847	1,236	(1,001)
	Capacity								
3	On-peak kWh	11,637	MWh	@	0.053506	623	0.060335	702	79
4	Off-peak kWh	54,082	MWh	@	0.036622	1,981	0.041296	2,233	253
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kWh	17,187	MWh	@	0.038335	659	0.021183	364	(295)
6	Off-peak kWh	95,088	MWh	@	0.031989	3,042	0.017676	1,681	(1,361)
	Capacity								
7	On-peak kWh	17,187	MWh	@	0.033954	584	0.038287	658	74
8	Off-peak kWh	95,088	MWh	@	0.028333	2,694	0.031949	3,038	344
	Provisions								
	Device Cycling								
9	AC Cycling(1)	3,816	Bills	@	(5.00)	(19)	(5.00)	(19)	-
10	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
11	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
12	Peak Time Rewards	30	MWh	@	(0.50)	(15)	(0.50)	(15)	-
	Critical Peak Pricing								
13	Critical-peak Charge	5	MWh	@	1.00	5	1.00	5	-
14	Off-peak Credits	1,456	MWh	@	(0.006373)	(9)	(0.006373)	(9)	-
15	Annual PSCR Factor	177,999	MWh	@	0.009410	1,675	0.009410	1,675	-
16	Total Production					$ 14,157		$ 11,937	$ (2,220)
	Transmission								
	Summer (June - Sept.)								
17	On-peak kWh	11,637	MWh	@	0.037988	$ 442	0.038586	$ 449	$ 7
18	Off-peak kWh	54,082	MWh	@	0.026001	1,406	0.026410	1,428	22
	Winter (Oct. - May)								
19	On-peak kWh	17,187	MWh	@	0.024106	414	0.024486	421	7
20	Off-peak kWh	95,088	MWh	@	0.020116	1,913	0.020432	1,943	30
21	Total Transmission					$ 4,175		$ 4,241	$ 66
	Delivery								
22	System Access	292,217	Bills	@	8.00	$ 2,338	8.00	$ 2,338	$ -
23	Distribution	177,999	MWh	@	0.093333	16,613	0.094572	16,834	221
	Provisions								
24	Senior Citizen (RSC)	48,048	Bills	@	(4.00)	(192)	(4.00)	(192)	-
25	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	13,378	Bills	@	(8.00)	(107)	(8.00)	(107)	-
27	Total Delivery					$ 18,652		$ 18,872	$ 221
28	Total Full Service					$ 36,984		$ 35,050	$ (1,934)
	ROA SERVICE								
	Delivery								
29	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
30	Distribution	-	MWh	@	0.093333	-	0.094572	-	-
	Provisions								
31	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
32	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
34	Total Delivery					$ -		$ -	$ -
35	Total Full & ROA Service					$ 36,984		$ 35,050	$ (1,934)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Nighttime Savers (RPM)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
Page: 7 of 32
Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	9,384	MWh	@	0.060410	$ 567	0.033381	$ 313	$ (254)
2	Off-peak kWh	19,685	MWh	@	0.046196	909	0.025526	502	(407)
3	Super Off-peak kWh	33,466	MWh	@	0.037381	1,251	0.020656	691	(560)
	Capacity								
4	On-peak kWh	9,384	MWh	@	0.053506	502	0.060335	566	64
5	Off-peak kWh	19,685	MWh	@	0.040916	805	0.046138	908	103
6	Super Off-peak kWh	33,466	MWh	@	0.033109	1,108	0.037334	1,249	141
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	13,591	MWh	@	0.038335	521	0.021183	288	(233)
8	Off-peak kWh	33,262	MWh	@	0.035960	1,196	0.019871	661	(535)
9	Super Off-peak kWh	58,994	MWh	@	0.028890	1,704	0.015964	942	(763)
	Capacity								
10	On-peak kWh	13,591	MWh	@	0.033954	461	0.038287	520	59
11	Off-peak kWh	33,262	MWh	@	0.031850	1,059	0.035915	1,195	135
12	Super Off-peak kWh	58,994	MWh	@	0.025588	1,510	0.028854	1,702	193
	Provisions								
	Device Cycling								
13	AC Cycling(1)	4,141	Bills	@	(5.00)	(21)	(5.00)	(21)	-
14	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
15	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
16	Peak Time Rewards	23	MWh	@	(0.50)	(11)	(0.50)	(11)	-
	Critical Peak Pricing								
17	Critical-peak Charge	1	MWh	@	1.00	1	1.00	1	-
18	Off-peak Credits	1,417	MWh	@	(0.006373)	(9)	(0.006373)	(9)	-
19	Annual PSCR Factor	168,382	MWh	@	0.009410	1,584	0.009410	1,584	-
20	Total Production					$ 13,139		$ 11,083	$ (2,056)
	Transmission								
	Summer (June - Sept.)								
21	On-peak kWh	9,384	MWh	@	0.037988	$ 356	0.038586	$ 362	$ 6
22	Off-peak kWh	19,685	MWh	@	0.029049	572	0.029507	581	9
23	Super Off-peak kWh	33,466	MWh	@	0.023506	787	0.023876	799	12
	Winter (Oct. - May)								
24	On-peak kWh	13,591	MWh	@	0.024106	328	0.024486	333	5
25	Off-peak kWh	33,262	MWh	@	0.022613	752	0.022969	764	12
26	Super Off-peak kWh	58,994	MWh	@	0.018167	1,072	0.018453	1,089	17
27	Total Transmission					$ 3,866		$ 3,927	$ 61
	Delivery								
28	System Access	202,551	Bills	@	8.00	$ 1,620	8.00	$ 1,620	$ -
29	Separately Metered EV Charger	295	Bills	@	(8.00)	$ (2)	(8.00)	$ (2)	$ -
30	Distribution	168,382	MWh	@	0.093333	15,716	0.094572	15,924	209
	Provisions								
31	Senior Citizen (RSC)	41,852	Bills	@	(4.00)	(167)	(4.00)	(167)	-
32	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	5,053	Bills	@	(8.00)	(40)	(8.00)	(40)	-
34	Total Delivery					$ 17,126		$ 17,334	$ 209
35	Total Full Service					$ 34,132		$ 32,345	$ (1,787)
	ROA SERVICE								
	Delivery								
36	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
37	Distribution	-	MWh	@	0.093333	-	0.094572	-	-
	Provisions								
38	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
39	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
40	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
41	Total Delivery					$ -		$ -	$ -
42	Total Full & ROA Service					$ 34,132		$ 32,345	$ (1,787)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Non-Transmitting Meters (RSM)

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Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c)	(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE									
	Production									
	Summer (June - Sept.)									
	Non-capacity									
1	First 600 kWh	23,089	MWh	@		0.033007	$ 762	0.018238	$ 421	$ (341)
2	Excess kWh	14,767	MWh	@		0.060410	892	0.033381	493	(399)
	Capacity									
3	First 600 kWh	23,089	MWh	@		0.029234	675	0.032965	761	86
4	Excess kWh	14,767	MWh	@		0.053506	790	0.060335	891	101
	Winter (Oct. - May)									
5	Non-capacity All kWh	70,407	MWh	@		0.033007	2,324	0.018238	1,284	(1,040)
6	Capacity All kWh	70,407	MWh	@		0.029234	2,058	0.032965	2,321	263
7	Annual PSCR Factor	108,263	MWh	@		0.009410	1,019	0.009410	1,019	-
8	Total Production						$ 8,520		$ 7,190	$ (1,330)
	Transmission									
	Summer (June - Sept.)									
9	First 600 kWh	23,089	MWh	@		0.020756	$ 479	0.021082	$ 487	$ 8
10	Excess kWh	14,767	MWh	@		0.037988	561	0.038586	570	9
	Winter (Oct. - May)									
11	All kWh	70,407	MWh	@		0.020756	1,461	0.021082	1,484	23
12	Total Transmission						$ 2,502		$ 2,541	$ 39
	Delivery									
13	System Access	131,680	Bills	@		8.00	$ 1,053	8.00	$ 1,053	$ -
14	Opt-out Fee	100,852	Bills	@		12.61	1,272	12.61	1,272	-
15	Distribution	108,263	MWh	@		0.093333	10,104	0.094572	10,239	134
	Provisions									
16	Senior Citizen (RSC)	36,309	Bills	@		(4.00)	(145)	(4.00)	(145)	-
17	Low Income Credit (LIAC)	-	Bills	@		(42.00)	-	(42.00)	-	-
18	Income Assistance (RIA)	4,599	Bills	@		(8.00)	(37)	(8.00)	(37)	-
19	Total Delivery						$ 12,248		$ 12,382	$ 134
20	Total Full Service						$ 23,269		$ 22,113	$ (1,157)
	ROA SERVICE									
	Delivery									
21	System Access	-	Bills	@		8.00	$ -	8.00	$ -	$ -
22	Opt-out Fee	-	Bills	@		12.61	-	12.61	-	-
23	Distribution	-	MWh	@		0.093333	-	0.094572	-	-
	Provisions									
24	Senior Citizen (RSC)	-	Bills	@		(4.00)	-	(4.00)	-	-
25	Low Income Credit (LIAC)	-	Bills	@		(42.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	-	Bills	@		(8.00)	-	(8.00)	-	-
27	Total Delivery						$ -		$ -	$ -
28	Total Full & ROA Service						$ 23,269		$ 22,113	$ (1,157)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Energy-only (GS)

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Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	1,447,697	MWh	@	0.046363	$ 67,119	0.027125	$ 39,269	$ (27,850)
2	Capacity All kWh	1,447,697	MWh	@	0.035056	50,750	0.039510	57,199	6,449
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,667,142	MWh	@	0.034013	90,716	0.019900	53,076	(37,641)
4	Capacity All kWh	2,667,142	MWh	@	0.025987	69,310	0.029289	78,118	8,808
5	Annual PSCR Factor	4,114,839	MWh	@	0.009410	38,721	0.009410	38,721	-
6	Total Production					$ 316,616		$ 266,383	$ (50,234)
	Transmission								
	Summer (June - Sept.)								
7	All kWh	1,447,697	MWh	@	0.026688	$ 38,636	0.027108	$ 39,245	$ 608
	Winter (Oct. - May)								
8	All kWh	2,667,142	MWh	@	0.019784	52,766	0.020095	53,597	831
9	Total Transmission					$ 91,403		$ 92,842	$ 1,439
	Delivery								
10	System Access	2,459,675	Bills	@	20.00	$ 49,193	20.00	$ 49,193	$ -
11	Distribution	4,114,839	MWh	@	0.069433	285,704	0.070829	291,451	5,747
	Provisions								
12	Education GEI	95,811	MWh	@	(0.001000)	(96)	(0.000914)	(88)	8
13	Total Delivery					$ 334,801		$ 340,557	$ 5,755
14	Total Full Service					$ 742,820		$ 699,782	$ (43,039)
	ROA SERVICE								
	Delivery								
15	System Access	1,014	Bills	@	20.00	$ 20	20.00	$ 20	$ -
16	Distribution	18,702	MWh	@	0.069433	1,299	0.070829	1,325	26
	Provisions								
17	Education GEI	11,475	MWh	@	(0.001000)	(11)	(0.000914)	(10)	1
18	Total Delivery					$ 1,307		$ 1,334	$ 27
19	Total Full & ROA Service					$ 744,128		$ 701,116	$ (43,012)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Time-of-Use (GSTU)

Case No.: U-22070
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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c)	(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE									
	Production									
	Summer (June - Sept.)									
	Non-capacity									
1	On-peak kWh	14,873	MWh	@		0.062830	$ 934	0.036760	$ 547	$ (388)
2	Mid-peak kWh	11,717	MWh	@		0.048934	573	0.028630	335	(238)
3	Off-peak kWh	4,487	MWh	@		0.036694	165	0.021469	96	(68)
	Capacity									
4	On-peak kWh	14,873	MWh	@		0.047982	714	0.054080	804	91
5	Mid-peak kWh	11,717	MWh	@		0.037369	438	0.042118	494	56
6	Off-peak kWh	4,487	MWh	@		0.028063	126	0.031629	142	16
	Winter (Oct. - May)									
	Non-capacity									
7	On-peak kWh	25,578	MWh	@		0.037107	949	0.021710	555	(394)
8	Off-peak kWh	27,907	MWh	@		0.030029	838	0.017569	490	(348)
	Capacity									
9	On-peak kWh	25,578	MWh	@		0.028428	727	0.032041	820	92
10	Off-peak kWh	27,907	MWh	@		0.022961	641	0.025879	722	81
	Provisions									
11	Interruptible (GSI)	-	MWh	@		(0.021695)	-	(0.021695)	-	-
12	Annual PSCR Factor	84,563	MWh	@		0.009410	796	0.009410	796	-
13	Total Production						$ 6,901		$ 5,801	$ (1,099)
	Transmission									
	Summer (June - Sept.)									
14	On-peak kWh	14,873	MWh	@		0.036529	$ 543	0.037105	$ 552	$ 9
15	Mid-peak kWh	11,717	MWh	@		0.028449	333	0.028897	339	5
16	Off-peak kWh	4,487	MWh	@		0.021365	96	0.021701	97	2
	Winter (Oct. - May)									
17	On-peak kWh	25,578	MWh	@		0.021643	554	0.021984	562	9
18	Off-peak kWh	27,907	MWh	@		0.017480	488	0.017756	496	8
19	Total Transmission						$ 2,014		$ 2,046	$ 32
	Delivery									
20	System Access	22,689	Bills	@		20.00	$ 454	20.00	$ 454	$ -
21	Distribution	84,563	MWh	@		0.069433	5,871	0.070829	5,990	118
	Provisions									
22	Education GEI	-	MWh	@		(0.001000)	-	(0.000914)	-	-
23	Total Delivery						$ 6,325		$ 6,443	$ 118
24	Total Full Service						$ 15,240		$ 14,290	$ (950)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Demand (GSD)

Case No.: U-22070
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Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Peak kW	2,893	MW	@	6.10	$ 17,632	4.90	$ 14,163	$ (3,469)
2	All kWh	1,048,776	MWh	@	0.032526	34,112	0.016966	17,793	(16,319)
	Capacity								
3	Peak kW	2,893	MW	@	10.17	29,425	11.47	33,177	3,753
4	All kWh	1,048,776	MWh	@	-	-	-	-	-
	Winter (Oct. - May)								
	Non-capacity								
5	Peak kW	5,338	MW	@	2.89	15,402	2.32	12,371	(3,031)
6	All kWh	1,930,830	MWh	@	0.023861	46,072	0.012446	24,032	(22,041)
	Capacity								
7	Peak kW	5,338	MW	@	9.05	48,326	10.21	54,490	6,164
8	All kWh	1,930,830	MWh	@	-	-	-	-	-
9	Power Factor Adjustment					269		220	(49)
	Provisions								
10	Interruptible (GSI)-Summer	29	MW	@	(8.50)	(247)	(8.50)	(247)	-
11	Interruptible (GSI)-Winter	53	MW	@	(7.50)	(398)	(7.50)	(398)	-
12	Annual PSCR Factor	2,979,606	MWh	@	0.009410	28,038	0.009410	28,038	-
13	Total Production					$ 218,633		$ 183,641	$ (34,992)
	Transmission								
	Summer (June - Sept.)								
14	Peak kW	2,893	MW	@	8.00	$ 23,147	8.13	$ 23,512	$ 365
	Winter (Oct. - May)								
15	Peak kW	5,338	MW	@	7.12	38,017	7.23	38,615	599
16	Total Transmission					$ 61,164		$ 62,127	$ 963
	Delivery								
17	System Access	241,823	Bills	@	30.00	$ 7,255	30.00	$ 7,255	$ -
18	Peak kW	8,231	MW	@	1.00	8,231	1.00	8,231	-
19	Distribution	2,979,606	MWh	@	0.057650	171,774	0.058483	174,257	2,483
20	Power Factor Adjustment					254		257	4
	Provisions								
21	Education GEI	131,112	MWh	@	(0.000820)	(107)	(0.000743)	(97)	10
22	Total Delivery					$ 187,406		$ 189,903	$ 2,497
23	Total Full Service					$ 467,203		$ 435,671	$ (31,532)
	ROA SERVICE								
	Delivery								
24	System Access	5,663	Bills	@	30.00	$ 170	30.00	$ 170	$ -
25	Peak kW	344	MW	@	1.00	344	1.00	344	-
26	Distribution	174,288	MWh	@	0.057650	10,048	0.058483	10,193	145
27	Power Factor Adjustment					16		16	0
	Provisions								
28	Education GEI	68,199	MWh	@	(0.000820)	(56)	(0.000743)	(51)	5
29	Total Delivery					$ 10,522		$ 10,673	$ 151
30	Total Full & ROA Service					$ 477,725		$ 446,344	$ (31,381)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 1 (GP VL 1)

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Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	1,101	MWh	@	0.043974	$ 48	0.027149	$ 30	$ (19)
2	Capacity All kWh	1,101	MWh	@	0.027595	30	0.031128	34	4
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,353	MWh	@	0.032261	76	0.019917	47	(29)
4	Capacity All kWh	2,353	MWh	@	0.021049	50	0.023745	56	6
5	Power Factor Adjustment					3		3	(1)
6	Annual PSCR Factor	3,454	MWh	@	0.009410	33	0.009410	33	-
7	Total Production					$ 240		$ 202	$ (38)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	1,101	MWh	@	0.023364	$ 26	0.023732	$ 26	$ 0
	Winter (Oct. - May)								
9	All kWh	2,353	MWh	@	0.017822	42	0.018103	43	1
10	Total Transmission					$ 68		$ 69	$ 1
	Delivery								
11	System Access	49	Bills	@	100.00	$ 5	100.00	$ 5	$ -
12	Distribution	3,454	MWh	@	0.006957	24	0.002478	9	(15)
13	Substation Ownership Credit	700	MWh	@	(0.004093)	(3)	(0.004093)	(3)	-
14	Power Factor Adjustment					0		0	(0)
	Provisions								
15	Education GEI	-	MWh	@	(0.000578)	-	(0.000511)	-	-
16	Total Delivery					$ 26		$ 11	$ (16)
17	Total Full Service					$ 334		$ 281	$ (53)
	ROA SERVICE								
	Delivery								
18	System Access	-	Bills	@	100.00	$ -	100.00	$ -	$ -
19	Distribution	-	MWh	@	0.006957	-	0.002478	-	-
20	Substation Ownership Credit	-	MWh	@	(0.004093)	-	(0.004093)	-	-
21	Power Factor Adjustment					-		-	-
	Provisions								
22	Education GEI	-	MWh	@	(0.000578)	-	(0.000511)	-	-
23	Total Delivery					$ -		$ -	$ -
24	Total Full & ROA Service					$ 334		$ 281	$ (53)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 2 (GP VL 2)

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Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	9,485	MWh	@	0.044489	$ 422	0.027466	$ 261	$ (161)
2	Capacity All kWh	9,485	MWh	@	0.027998	266	0.031583	300	34
	Winter (Oct. - May)								
3	Non-capacity All kWh	21,775	MWh	@	0.032638	711	0.020150	439	(272)
4	Capacity All kWh	21,775	MWh	@	0.021357	465	0.024091	525	60
5	Power Factor Adjustment					49		40	(9)
6	Annual PSCR Factor	31,259	MWh	@	0.009410	294	0.009410	294	-
7	Total Production					$ 2,206		$ 1,857	$ (349)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	9,485	MWh	@	0.023706	$ 225	0.024079	$ 228	$ 4
	Winter (Oct. - May)								
9	All kWh	21,775	MWh	@	0.018083	394	0.018367	400	6
10	Total Transmission					$ 619		$ 628	$ 10
	Delivery								
11	System Access	435	Bills	@	100.00	$ 43	100.00	$ 43	$ -
12	Distribution	31,259	MWh	@	0.010996	344	0.011184	350	6
13	Substation Ownership Credit	6,580	MWh	@	(0.004513)	(30)	(0.004513)	(30)	-
14	Power Factor Adjustment					8		8	0
	Provisions								
15	Education GEI	-	MWh	@	(0.000578)	-	(0.000511)	-	-
16	Total Delivery					$ 366		$ 372	$ 6
17	Total Full Service					$ 3,191		$ 2,858	$ (333)
	ROA SERVICE								
	Delivery								
18	System Access	24	Bills	@	100.00	$ 2	100.00	$ 2	$ -
19	Distribution	1,783	MWh	@	0.010996	20	0.011184	20	0
20	Substation Ownership Credit	-	MWh	@	(0.004513)	-	(0.004513)	-	-
21	Power Factor Adjustment					(0)		(0)	(0)
	Provisions								
22	Education GEI	-	MWh	@	(0.000578)	-	(0.000511)	-	-
23	Total Delivery					$ 22		$ 22	$ 0
24	Total Full & ROA Service					$ 3,212		$ 2,880	$ (333)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 3 (GP VL 3)

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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	221,271	MWh	@	0.044937	$ 9,943	0.027743	$ 6,139	$ (3,805)
2	Capacity All kWh	221,271	MWh	@	0.028442	6,293	0.032084	7,099	806
	Winter (Oct. - May)								
3	Non-capacity All kWh	410,967	MWh	@	0.032967	13,548	0.020353	8,364	(5,184)
4	Capacity All kWh	410,967	MWh	@	0.021696	8,916	0.024474	10,058	1,142
5	Power Factor Adjustment					486		397	(88)
6	Annual PSCR Factor	632,239	MWh	@	0.009410	5,949	0.009410	5,949	-
7	Total Production					$ 45,136		$ 38,007	$ (7,130)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	221,271	MWh	@	0.024082	$ 5,329	0.024461	$ 5,413	$ 84
	Winter (Oct. - May)								
9	All kWh	410,967	MWh	@	0.018370	7,549	0.018659	7,668	119
10	Total Transmission					$ 12,878		$ 13,081	$ 203
	Delivery								
11	System Access	15,834	Bills	@	100.00	$ 1,583	100.00	$ 1,583	$ -
12	Distribution	632,239	MWh	@	0.024415	15,436	0.024993	15,801	365
13	Power Factor Adjustment					194		198	5
	Provisions								
14	Education GEI	85,102	MWh	@	(0.000578)	(49)	(0.000511)	(43)	6
15	Total Delivery					$ 17,164		$ 17,540	$ 376
16	Total Full Service					$ 75,178		$ 68,627	$ (6,551)
	ROA SERVICE								
	Delivery								
17	System Access	696	Bills	@	100.00	$ 70	100.00	$ 70	$ -
18	Distribution	70,285	MWh	@	0.024415	1,716	0.024993	1,757	41
19	Power Factor Adjustment					5		5	0
	Provisions								
20	Education GEI	36,890	MWh	@	(0.000578)	(21)	(0.000511)	(19)	2
21	Total Delivery					$ 1,770		$ 1,813	$ 43
22	Total Full & ROA Service					$ 76,948		$ 70,440	$ (6,508)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 1 (GPD VL 1)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	668	MW	@	5.96	$ 3,979	4.94	$ 3,299	$ (680)
2	On-peak kWh	86,218	MWh	@	0.040427	3,486	0.023463	2,023	(1,463)
3	Off-peak kWh	296,066	MWh	@	0.026219	7,762	0.015217	4,505	(3,257)
4	Capacity On-peak kW	668	MW	@	10.06	6,719	11.37	7,590	871
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,369	MW	@	5.15	7,050	4.27	5,844	(1,205)
6	On-peak kWh	179,258	MWh	@	0.025351	4,544	0.014714	2,638	(1,907)
7	Off-peak kWh	605,998	MWh	@	0.022012	13,339	0.012776	7,742	(5,597)
8	Capacity On-peak kW	1,369	MW	@	9.33	12,777	10.54	14,433	1,656
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	60	MW	@	(8.50)	(514)	(8.50)	(514)	-
11	Winter Contracted kW	121	MW	@	(7.50)	(905)	(7.50)	(905)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.029081	-	0.029831	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.026985	-	0.027792	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.028485	-	-
16	Summer Transmission	-	MWh		-	-	0.016191	-	-
17	Winter Capacity	-	MWh		-	-	0.025823	-	-
18	Winter Transmission	-	MWh		-	-	0.015046	-	-
19	Critical Peak Event	-	MWh		-	-	1.00	-	-
20	Power Factor Adjustment					(122)		(98)	24
21	Annual PSCR Factor	1,167,540	MWh	@	0.009410	10,987	0.009410	10,987	-
22	Total Production					$ 69,103		$ 57,544	$ (11,559)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	668	MW	@	9.13	$ 6,094	9.27	$ 6,189	$ 96
	Winter (Oct. - May)								
24	On-peak kW	1,369	MW	@	8.50	11,632	8.63	11,815	183
25	Total Transmission					$ 17,725		$ 18,004	$ 279
	Delivery								
26	System Access	267	Bills	@	200.00	$ 53	200.00	$ 53	$ -
27	Maximum kW	2,528	MW	@	2.37	5,996	0.85	2,145	(3,851)
28	Substation Ownership	42	MW	@	(1.82)	(76)	(1.82)	(76)	-
29	Distribution	1,167,540	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(12)		(4)	8
	Provisions								
31	Education GEI	-	MWh	@	(0.000205)	-	(0.000175)	-	-
32	Total Delivery					$ 5,961		$ 2,117	$ (3,843)
33	Total Full Service					$ 92,789		$ 77,666	$ (15,123)
	ROA SERVICE								
	Delivery								
34	System Access	169	Bills	@	200.00	$ 34	200.00	$ 34	$ -
35	Maximum kW	2,403	MW	@	2.37	5,700	0.85	2,039	(3,661)
36	Substation Ownership	196	MW	@	(1.82)	(356)	(1.82)	(356)	-
37	Distribution	1,270,576	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					(14)		(4)	9
	Provisions								
39	Education GEI	2,675	MWh	@	(0.000205)	(1)	(0.000175)	(0)	0
40	Total Delivery					$ 5,364		$ 1,712	$ (3,652)
41	Total Full & ROA Service					$ 98,153		$ 79,378	$ (18,775)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 2 (GPD VL 2)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	886	MW	@	6.03	$ 5,340	5.00	$ 4,427	$ (913)
2	On-peak kWh	121,063	MWh	@	0.040900	4,951	0.023738	2,874	(2,078)
3	Off-peak kWh	357,634	MWh	@	0.026526	9,486	0.015395	5,506	(3,981)
4	Capacity On-peak kW	886	MW	@	10.21	9,042	11.53	10,214	1,172
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,801	MW	@	5.21	9,381	4.32	7,777	(1,604)
6	On-peak kWh	240,894	MWh	@	0.025648	6,178	0.014886	3,586	(2,593)
7	Off-peak kWh	733,449	MWh	@	0.022270	16,334	0.012925	9,480	(6,854)
8	Capacity On-peak kW	1,801	MW	@	9.47	17,051	10.70	19,261	2,210
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	40	MW	@	(8.50)	(343)	(8.50)	(343)	-
11	Winter Contracted kW	81	MW	@	(7.50)	(608)	(7.50)	(608)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.031449	-	0.032260	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.029198	-	0.030071	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.030585	-	-
16	Summer Transmission	-	MWh		-	-	0.017399	-	-
17	Winter Capacity	-	MWh		-	-	0.027751	-	-
18	Winter Transmission	-	MWh		-	-	0.008548	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					(103)		(84)	20
21	Annual PSCR Factor	1,453,040	MWh	@	0.009410	13,673	0.009410	13,673	-
22	Total Production					$ 90,384		$ 75,764	$ (14,620)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	886	MW	@	9.26	$ 8,200	9.41	$ 8,329	$ 129
	Winter (Oct. - May)								
24	On-peak kW	1,801	MW	@	8.62	15,523	8.76	15,767	244
25	Total Transmission					$ 23,723		$ 24,096	$ 374
	Delivery								
26	System Access	721	Bills	@	200.00	$ 144	200.00	$ 144	$ -
27	Maximum kW	3,094	MW	@	3.61	11,178	3.69	11,415	236
28	Substation Ownership	269	MW	@	(1.93)	(520)	(1.93)	(520)	-
29	Distribution	1,453,040	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(14)		(15)	(0)
	Provisions								
31	Education GEI	29,734	MWh	@	(0.000205)	(6)	(0.000175)	(5)	1
32	Total Delivery					$ 10,782		$ 11,019	$ 237
33	Total Full Service					$ 124,888		$ 110,879	$ (14,009)
	ROA SERVICE								
	Delivery								
34	System Access	453	Bills	@	200.00	$ 91	200.00	$ 91	$ -
35	Maximum kW	2,306	MW	@	3.61	8,331	3.69	8,508	176
36	Substation Ownership	298	MW	@	(1.93)	(576)	(1.93)	(576)	-
37	Distribution	1,080,207	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					16		16	0
	Provisions								
39	Education GEI	66,701	MWh	@	(0.000205)	(14)	(0.000175)	(12)	2
40	Total Delivery					$ 7,848		$ 8,027	$ 179
41	Total Full & ROA Service					$ 132,737		$ 118,906	$ (13,831)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 3 (GPD VL 3)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	1,514	MW	@	6.09	$ 9,218	5.05	$ 7,643	$ (1,575)
2	On-peak kWh	209,315	MWh	@	0.041312	8,647	0.023977	5,019	(3,628)
3	Off-peak kWh	587,189	MWh	@	0.026793	15,733	0.015550	9,131	(6,602)
4	Capacity On-peak kW	1,514	MW	@	10.37	15,697	11.72	17,736	2,040
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	3,075	MW	@	5.26	16,175	4.36	13,415	(2,761)
6	On-peak kWh	417,471	MWh	@	0.025907	10,815	0.015036	6,277	(4,538)
7	Off-peak kWh	1,200,805	MWh	@	0.022495	27,012	0.013055	15,677	(11,335)
8	Capacity On-peak kW	3,075	MW	@	9.62	29,583	10.87	33,413	3,830
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	4	MW	@	(8.50)	(34)	(8.50)	(34)	-
11	Winter Contracted kW	8	MW	@	(7.50)	(57)	(7.50)	(57)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.033010	-	0.033868	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.031900	-	0.032841	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.031864	-	-
16	Summer Transmission	-	MWh		-	-	0.018158	-	-
17	Winter Capacity	-	MWh		-	-	0.028937	-	-
18	Winter Transmission	-	MWh		-	-	0.016902	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					91		74	(17)
21	Annual PSCR Factor	2,414,780	MWh	@	0.009410	22,723	0.009410	22,723	-
22	Total Production					$ 155,603		$ 131,016	$ (24,587)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	1,514	MW	@	9.41	$ 14,244	9.55	$ 14,463	$ 219
	Winter (Oct. - May)								
24	On-peak kW	3,075	MW	@	8.76	26,938	8.89	27,352	414
25	Total Transmission					$ 41,182		$ 41,815	$ 633
	Delivery								
26	System Access	9,273	Bills	@	200.00	$ 1,855	200.00	$ 1,855	$ -
27	Maximum kW	5,899	MW	@	6.68	39,405	6.87	40,506	1,101
28	Distribution	2,414,780	MWh	@	-	-	-	-	-
29	Power Factor Adjustment					27		28	1
	Provisions								
30	Education GEI	110,078	MWh	@	(0.000204)	(22)	(0.000175)	(19)	3
31	Total Delivery					$ 41,264		$ 42,369	$ 1,105
32	Total Full Service					$ 238,049		$ 215,200	$ (22,849)
	ROA SERVICE								
	Delivery								
33	System Access	3,656	Bills	@	200.00	$ 731	200.00	$ 731	$ -
34	Maximum kW	2,542	MW	@	6.68	16,986	6.87	17,457	471
35	Distribution	953,091	MWh	@	-	-	-	-	-
36	Power Factor Adjustment					37		38	1
	Provisions								
37	Education GEI	149,120	MWh	@	(0.000204)	(30)	(0.000175)	(26)	4
38	Total Delivery					$ 17,724		$ 18,200	$ 476
39	Total Full & ROA Service					$ 255,773		$ 233,400	$ (22,373)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Large Load Voltage Level 1

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	3,600	MW	@	5.96	$ -	7.00	$ 25,216	$ 25,216
2	On-peak kWh	878,400	MWh	@	0.040427	-	0.023274	20,443	20,443
3	Off-peak kWh	1,756,800	MWh	@	0.026219	-	0.015094	26,517	26,517
4	Capacity On-peak kW	3,600	MW	@	10.06	-	12.87	46,326	46,326
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	7,200	MW	@	5.15	-	6.05	43,570	43,570
6	On-peak kWh	1,749,600	MWh	@	0.025351	-	0.014595	25,535	25,535
7	Off-peak kWh	3,499,200	MWh	@	0.022012	-	0.012672	44,343	44,343
8	Capacity On-peak kW	7,200	MW	@	9.33	-	11.93	85,915	85,915
	Provisions								
20	Power Factor Adjustment					-			-
21	Annual PSCR Factor	7,884,000	MWh	@	0.009410	-	0.009410	74,188	74,188
22	Total Production					$ -		$ 392,054	$ 392,054
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	3,600	MW	@	9.13	$ -	11.02	$ 39,656	$ 39,656
	Winter (Oct. - May)								
24	On-peak kW	7,200	MW	@	8.50	-	10.25	73,831	73,831
25	Total Transmission					$ -		$ 113,487	$ 113,487
	Delivery								
26	System Access	12	Bills	@	200.00	$ -	200.00	$ 2	$ 2
27	Maximum kW	10,800	MW	@	2.37	-	1.75	18,951	18,951
28	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
29	Distribution	7,884,000	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					-			-
	Provisions								
31	Education GEI	-	MWh	@	(0.000205)	-	(0.000122)	-	-
32	Total Delivery					$ -		$ 18,954	$ 18,954
33	Total Full Service					$ -		$ 524,494	$ 524,494

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 1 (GPTU VL 1)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	13,186	MWh	@	0.061877	$ 816	0.039165	$ 516	$ (299)
2	Mid-peak kWh	17,748	MWh	@	0.055068	977	0.034855	619	(359)
3	Low-peak kWh	48,608	MWh	@	0.044513	2,164	0.028175	1,370	(794)
4	Off-peak kWh	86,924	MWh	@	0.033174	2,884	0.020998	1,825	(1,058)
	Capacity								
5	High-peak kWh	13,186	MWh	@	0.035267	465	0.039765	524	59
6	Mid-peak kWh	17,748	MWh	@	0.031400	557	0.035405	628	71
7	Low-peak kWh	48,608	MWh	@	0.025306	1,230	0.028533	1,387	157
8	Off-peak kWh	86,924	MWh	@	0.018927	1,645	0.021341	1,855	210
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	26,006	MWh	@	0.039842	1,036	0.025218	656	(380)
10	Mid-peak kWh	36,415	MWh	@	0.036938	1,345	0.023380	851	(494)
11	Off-peak kWh	235,629	MWh	@	0.031011	7,307	0.019628	4,625	(2,682)
	Capacity								
12	High-peak kWh	26,006	MWh	@	0.022720	591	0.025617	666	75
13	Mid-peak kWh	36,415	MWh	@	0.021035	766	0.023717	864	98
14	Off-peak kWh	235,629	MWh	@	0.017499	4,123	0.019731	4,649	526
15	Power Factor Adjustment					42		34	(8)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	464,518	MWh	@	0.009410	4,371	0.009410	4,371	-
19	Total Production					$ 30,320		$ 25,441	$ (4,879)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	13,186	MWh	@	0.030861	$ 407	0.031347	$ 413	$ 6
21	Mid-peak kWh	17,748	MWh	@	0.027477	488	0.027910	495	8
22	Low-peak kWh	48,608	MWh	@	0.022144	1,076	0.022493	1,093	17
23	Off-peak kWh	86,924	MWh	@	0.016563	1,440	0.016824	1,462	23
24	Winter (Oct. - May)								
25	High-peak kWh	26,006	MWh	@	0.019881	517	0.020194	525	8
26	Mid-peak kWh	36,415	MWh	@	0.018407	670	0.018697	681	11
27	Off-peak kWh	235,629	MWh	@	0.015313	3,608	0.015554	3,665	57
28	Total Transmission					$ 8,206		$ 8,335	$ 129
	Delivery								
29	System Access	280	Bills	@	200.00	$ 56	200.00	$ 56	$ -
30	Maximum kW	1,315	MW	@	2.37	3,119	0.85	1,116	(2,003)
31	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
32	Distribution	464,518	MWh	@	-	-	-	-	-
33	Power Factor Adjustment					5		2	(3)
	Provisions								
34	Education GEI	39,403	MWh	@	(0.000205)	(8)	(0.000175)	(7)	1
35	Total Delivery					$ 3,172		$ 1,166	$ (2,005)
36	Total Full Service					$ 41,698		$ 34,943	$ (6,755)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 2 (GPTU VL 2)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
Page: 20 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	16,699	MWh	@	0.062601	$ 1,045	0.039624	$ 662	$ (384)
2	Mid-peak kWh	22,367	MWh	@	0.055712	1,246	0.035263	789	(457)
3	Low-peak kWh	51,905	MWh	@	0.045034	2,337	0.028504	1,480	(858)
4	Off-peak kWh	84,694	MWh	@	0.033562	2,843	0.021243	1,799	(1,043)
	Capacity								
5	High-peak kWh	16,699	MWh	@	0.035782	598	0.040345	674	76
6	Mid-peak kWh	22,367	MWh	@	0.031859	713	0.035921	803	91
7	Low-peak kWh	51,905	MWh	@	0.025675	1,333	0.028950	1,503	170
8	Off-peak kWh	84,694	MWh	@	0.019204	1,626	0.021653	1,834	207
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	32,702	MWh	@	0.040309	1,318	0.025513	834	(484)
10	Mid-peak kWh	44,338	MWh	@	0.037370	1,657	0.023654	1,049	(608)
11	Off-peak kWh	243,938	MWh	@	0.031374	7,653	0.019858	4,844	(2,809)
	Capacity								
12	High-peak kWh	32,702	MWh	@	0.023051	754	0.025991	850	96
13	Mid-peak kWh	44,338	MWh	@	0.021342	946	0.024064	1,067	121
14	Off-peak kWh	243,938	MWh	@	0.017754	4,331	0.020019	4,883	552
15	Power Factor Adjustment					(12)		(10)	2
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	496,642	MWh	@	0.009410	4,673	0.009410	4,673	-
19	Total Production					$ 33,061		$ 27,734	$ (5,328)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	16,699	MWh	@	0.031312	$ 523	0.031805	$ 531	$ 8
21	Mid-peak kWh	22,367	MWh	@	0.027879	624	0.028318	633	10
22	Low-peak kWh	51,905	MWh	@	0.022468	1,166	0.022821	1,185	18
23	Off-peak kWh	84,694	MWh	@	0.016805	1,423	0.017069	1,446	22
	Winter (Oct. - May)								
24	High-peak kWh	32,702	MWh	@	0.020172	660	0.020489	670	10
25	Mid-peak kWh	44,338	MWh	@	0.018676	828	0.018970	841	13
26	Off-peak kWh	243,938	MWh	@	0.015536	3,790	0.015781	3,850	60
27	Total Transmission					$ 9,013		$ 9,155	$ 142
	Delivery								
28	System Access	963	Bills	@	200.00	$ 193	200.00	$ 193	$ -
29	Maximum kW	1,431	MW	@	3.61	5,168	3.69	5,277	109
30	Substation Ownership	235	MW	@	(1.93)	(453)	(1.93)	(453)	-
31	Distribution	496,642	MWh	@	-	-	-	-	-
32	Power Factor Adjustment					(2)		(2)	(0)
	Provisions								
33	Education GEI	18,544	MWh	@	(0.000205)	(4)	(0.000175)	(3)	1
34	Total Delivery					$ 4,902		$ 5,012	$ 110
35	Total Full Service					$ 46,976		$ 41,901	$ (5,076)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 3 (GPTU VL 3)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
Page: 21 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	127,203	MWh	@	0.063232	$ 8,043	0.040023	$ 5,091	$ (2,952)
2	Mid-peak kWh	168,181	MWh	@	0.056274	9,464	0.035619	5,990	(3,474)
3	Low-peak kWh	375,163	MWh	@	0.045488	17,065	0.028792	10,802	(6,264)
4	Off-peak kWh	562,171	MWh	@	0.033901	19,058	0.021457	12,063	(6,995)
	Capacity								
5	High-peak kWh	127,203	MWh	@	0.036350	4,624	0.040986	5,214	590
6	Mid-peak kWh	168,181	MWh	@	0.032364	5,443	0.036491	6,137	694
7	Low-peak kWh	375,163	MWh	@	0.026083	9,785	0.029409	11,033	1,248
8	Off-peak kWh	562,171	MWh	@	0.019509	10,967	0.021997	12,366	1,399
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	216,061	MWh	@	0.040715	8,797	0.025771	5,568	(3,229)
10	Mid-peak kWh	295,549	MWh	@	0.037747	11,156	0.023892	7,061	(4,095)
11	Off-peak kWh	1,567,912	MWh	@	0.031690	49,687	0.020058	31,449	(18,238)
	Capacity								
12	High-peak kWh	216,061	MWh	@	0.023417	5,060	0.026403	5,705	645
13	Mid-peak kWh	295,549	MWh	@	0.021680	6,408	0.024445	7,225	817
14	Off-peak kWh	1,567,912	MWh	@	0.018036	28,279	0.020336	31,886	3,606
15	Power Factor Adjustment					456		370	(85)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	3,312,240	MWh	@	0.009410	31,168	0.009410	31,168	-
19	Total Production					$ 225,460		$ 189,128	$ (36,332)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	127,203	MWh	@	0.031809	$ 4,046	0.032310	$ 4,110	$ 64
21	Mid-peak kWh	168,181	MWh	@	0.028321	4,763	0.028767	4,838	75
22	Low-peak kWh	375,163	MWh	@	0.022824	8,563	0.023184	8,698	135
23	Off-peak kWh	562,171	MWh	@	0.017071	9,597	0.017340	9,748	151
	Winter (Oct. - May)								
24	High-peak kWh	216,061	MWh	@	0.020492	4,427	0.020814	4,497	70
25	Mid-peak kWh	295,549	MWh	@	0.018972	5,607	0.019271	5,695	88
26	Off-peak kWh	1,567,912	MWh	@	0.015783	24,746	0.016031	25,136	390
27	Total Transmission					$ 61,750		$ 62,722	$ 972
	Delivery								
28	System Access	16,957	Bills	@	200.00	$ 3,391	200.00	$ 3,391	$ -
29	Maximum kW	10,275	MW	@	6.68	68,656	6.87	70,558	1,902
30	Distribution	3,312,240	MWh	@	-	-	-	-	-
31	Power Factor Adjustment					161		166	4
	Provisions								
32	Education GEI	278,712	MWh	@	(0.000204)	(57)	(0.000175)	(49)	8
33	Total Delivery					$ 72,152		$ 74,067	$ 1,914
34	Total Full Service					$ 359,362		$ 325,917	$ (33,445)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 1 (EIP VL 1)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	206	MWh	@	0.099498	$ 21	0.066850	$ 14	$ (7)
2	High-peak kWh	7,015	MWh	@	0.066332	465	0.044567	313	(153)
3	Mid-peak kWh	7,214	MWh	@	0.059487	429	0.039968	288	(141)
4	Low-peak kWh	45,458	MWh	@	0.047278	2,149	0.031765	1,444	(705)
5	Off-peak kWh	61,205	MWh	@	0.034619	2,119	0.023260	1,424	(695)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	206	MWh	@	0.040218	8	0.045508	9	1
8	High-peak kWh	7,015	MWh	@	0.026812	188	0.030339	213	25
9	Mid-peak kWh	7,214	MWh	@	0.023872	172	0.027012	195	23
10	Low-peak kWh	45,458	MWh	@	0.019239	875	0.021769	990	115
11	Off-peak kWh	61,205	MWh	@	0.014390	881	0.016282	997	116
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	647	MWh	@	0.062127	40	0.041742	27	(13)
13	High-peak kWh	14,105	MWh	@	0.041418	584	0.027828	393	(192)
14	Mid-peak kWh	14,704	MWh	@	0.038779	570	0.026054	383	(187)
15	Off-peak kWh	182,038	MWh	@	0.032609	5,936	0.021909	3,988	(1,948)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	647	MWh	@	0.025909	17	0.029317	19	2
18	High-peak kWh	14,105	MWh	@	0.017272	244	0.019545	276	32
19	Mid-peak kWh	14,704	MWh	@	0.015992	235	0.018095	266	31
20	Off-peak kWh	182,038	MWh	@	0.013303	2,422	0.015053	2,740	319
21	Power Factor Adjustment					7		5	(1)
22	Interruptible Credit	332,592	MWh	@	(0.008461)	(2,814)	(0.008461)	(2,814)	-
23	Annual PSCR Factor	332,592	MWh	@	0.009410	3,130	0.009410	3,130	-
24	Total Production					$ 17,677		$ 14,298	$ (3,379)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	206	MWh	@	0.041546	$ 9	0.042201	$ 9	$ 0
26	High-peak kWh	7,015	MWh	@	0.027698	194	0.028134	197	3
27	Mid-peak kWh	7,214	MWh	@	0.024660	178	0.025049	181	3
28	Low-peak kWh	45,458	MWh	@	0.019874	903	0.020187	918	14
29	Off-peak kWh	61,205	MWh	@	0.014865	910	0.015099	924	14
	Winter (Oct. - May)								
30	Critical-peak kWh	647	MWh	@	0.026765	17	0.027186	18	0
31	High-peak kWh	14,105	MWh	@	0.017843	252	0.018124	256	4
32	Mid-peak kWh	14,704	MWh	@	0.016520	243	0.016780	247	4
33	Off-peak kWh	182,038	MWh	@	0.013743	2,502	0.013959	2,541	39
34	Total Transmission					$ 5,208		$ 5,290	$ 82
	Delivery								
35	System Access	64	Bills	@	200.00	$ 13	200.00	$ 13	$ -
36	Maximum kW	771	MW	@	2.37	1,830	0.85	654	(1,175)
37	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
38	Power Factor Adjustment					1		0	(0)
39	Distribution	332,592	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,843		$ 668	$ (1,176)
41	Total Full Service					$ 24,728		$ 20,256	$ (4,472)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 2 (EIP VL 2)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	27	MWh	@	0.100662	$ 3	0.067632	$ 2	$ (1)
2	High-peak kWh	895	MWh	@	0.067108	60	0.045088	40	(20)
3	Mid-peak kWh	937	MWh	@	0.060183	56	0.040436	38	(19)
4	Low-peak kWh	7,371	MWh	@	0.047832	353	0.032137	237	(116)
5	Off-peak kWh	10,461	MWh	@	0.035024	366	0.023532	246	(120)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	27	MWh	@	0.040805	1	0.046172	1	0
8	High-peak kWh	895	MWh	@	0.027203	24	0.030782	28	3
9	Mid-peak kWh	937	MWh	@	0.024220	23	0.027406	26	3
10	Low-peak kWh	7,371	MWh	@	0.019519	144	0.022087	163	19
11	Off-peak kWh	10,461	MWh	@	0.014600	153	0.016520	173	20
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	79	MWh	@	0.062854	5	0.042230	3	(2)
13	High-peak kWh	1,503	MWh	@	0.041903	63	0.028153	42	(21)
14	Mid-peak kWh	1,737	MWh	@	0.039232	68	0.026359	46	(22)
15	Off-peak kWh	30,227	MWh	@	0.032990	997	0.022165	670	(327)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	79	MWh	@	0.026287	2	0.029745	2	0
18	High-peak kWh	1,503	MWh	@	0.017525	26	0.019830	30	3
19	Mid-peak kWh	1,737	MWh	@	0.016225	28	0.018359	32	4
20	Off-peak kWh	30,227	MWh	@	0.013498	408	0.015273	462	54
21	Power Factor Adjustment					(14)		(11)	3
22	Interruptible Credit	53,237	MWh	@	(0.008461)	(450)	(0.008461)	(450)	-
23	Annual PSCR Factor	53,237	MWh	@	0.009410	501	0.009410	501	-
24	Total Production					$ 2,817		$ 2,280	$ (538)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	27	MWh	@	0.042153	$ 1	0.042817	$ 1	$ 0
26	High-peak kWh	895	MWh	@	0.028102	25	0.028544	26	0
27	Mid-peak kWh	937	MWh	@	0.025021	23	0.025415	24	0
28	Low-peak kWh	7,371	MWh	@	0.020164	149	0.020482	151	2
29	Off-peak kWh	10,461	MWh	@	0.015082	158	0.015320	160	2
	Winter (Oct. - May)								
30	Critical-peak kWh	79	MWh	@	0.027155	2	0.027583	2	0
31	High-peak kWh	1,503	MWh	@	0.018104	27	0.018389	28	0
32	Mid-peak kWh	1,737	MWh	@	0.016761	29	0.017025	30	0
33	Off-peak kWh	30,227	MWh	@	0.013944	421	0.014163	428	7
34	Total Transmission					$ 836		$ 849	$ 13
	Delivery								
35	System Access	82	Bills	@	200.00	$ 16	200.00	$ 16	$ -
36	Maximum kW	373	MW	@	3.61	1,347	3.69	1,375	28
37	Substation Ownership	169	MW	@	(1.93)	(326)	(1.93)	(326)	-
38	Power Factor Adjustment					(5)		(5)	(0)
39	Distribution	53,237	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,032		$ 1,060	$ 28
41	Total Full Service					$ 4,685		$ 4,189	$ (496)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 3 (EIP VL 3)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c) Present Rate $/unit	(d) Present Revenue $000	(e) Proposed Rate $/unit	(f) Proposed Revenue $000	(g) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	1	MWh	@	0.101677	$ 0	0.068314	$ 0	$ (0)
2	High-peak kWh	66	MWh	@	0.067784	5	0.045543	3	(1)
3	Mid-peak kWh	104	MWh	@	0.060790	6	0.040843	4	(2)
4	Low-peak kWh	1,569	MWh	@	0.048314	76	0.032461	51	(25)
5	Off-peak kWh	908	MWh	@	0.035378	32	0.023769	22	(11)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	1	MWh	@	0.041452	0	0.046905	0	0
8	High-peak kWh	66	MWh	@	0.027635	2	0.031270	2	0
9	Mid-peak kWh	104	MWh	@	0.024605	3	0.027841	3	0
10	Low-peak kWh	1,569	MWh	@	0.019829	31	0.022438	35	4
11	Off-peak kWh	908	MWh	@	0.014831	13	0.016782	15	2
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	4	MWh	@	0.063488	0	0.042656	0	(0)
13	High-peak kWh	93	MWh	@	0.042325	4	0.028437	3	(1)
14	Mid-peak kWh	119	MWh	@	0.039628	5	0.026625	3	(2)
15	Off-peak kWh	3,871	MWh	@	0.033323	129	0.022389	87	(42)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	4	MWh	@	0.026704	0	0.030217	0	0
18	High-peak kWh	93	MWh	@	0.017803	2	0.020145	2	0
19	Mid-peak kWh	119	MWh	@	0.016483	2	0.018651	2	0
20	Off-peak kWh	3,871	MWh	@	0.013712	53	0.015516	60	7
21	Power Factor Adjustment					(1)		(1)	0
22	Interruptible Credit	6,737	MWh	@	(0.008461)	(57)	(0.008461)	(57)	-
23	Annual PSCR Factor	6,737	MWh	@	0.009410	63	0.009410	63	-
24	Total Production					$ 368		$ 298	$ (70)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	1	MWh	@	0.042822	$ 0	0.043496	$ 0	$ 0
26	High-peak kWh	66	MWh	@	0.028548	2	0.028997	2	0
27	Mid-peak kWh	104	MWh	@	0.025418	3	0.025818	3	0
28	Low-peak kWh	1,569	MWh	@	0.020484	32	0.020807	33	1
29	Off-peak kWh	908	MWh	@	0.015321	14	0.015563	14	0
	Winter (Oct. - May)								
30	Critical-peak kWh	4	MWh	@	0.027586	0	0.028021	0	0
31	High-peak kWh	93	MWh	@	0.018391	2	0.018681	2	0
32	Mid-peak kWh	119	MWh	@	0.017027	2	0.017295	2	0
33	Off-peak kWh	3,871	MWh	@	0.014165	55	0.014388	56	1
34	Total Transmission					$ 109		$ 111	$ 2
	Delivery								
35	System Access	54	Bills	@	200.00	$ 11	200.00	$ 11	$ -
36	Maximum kW	40	MW	@	6.68	267	6.87	274	7
37	Power Factor Adjustment					(1)		(1)	(0)
38	Distribution	6,737	MWh	@	-	-	-	-	-
39	Total Delivery					$ 277		$ 284	$ 7
40	Total Full Service					$ 754		$ 693	$ (61)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Metered Lighting (GML)

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
1	Secondary All kWh	10,328	MWh	@	0.034716	$ 359	0.026629	$ 275	$ (84)
2	Primary All kWh	448	MWh	@	0.017037	8	0.013068	6	(2)
3	Annual PSCR Factor	10,776	MWh	@	0.009410	101	0.009410	101	-
4	Total Production					$ 468		$ 382	$ (85)
	Transmission								
5	Secondary All kWh	10,328	MWh	@	0.010556	109	0.010722	111	2
6	Primary All kWh	448	MWh	@	0.005180	2	0.005262	2	0
7	Total Transmission	10,776				111		113	2
	Delivery								
	Secondary								
8	System Access	4,489	Bills	@	10.00	$ 45	10.00	$ 45	$ -
9	Distribution	10,328	MWh	@	0.118564	1,225	0.119676	1,236	11
	Primary								
10	System Access	297	Bills	@	20.00	$ 6	20.00	$ 6	$ -
11	Distribution	448	MWh	@	0.090355	41	0.091203	41	0
12	Total Delivery					$ 1,316		$ 1,328	$ 12
13	Total Full Service					$ 1,895		$ 1,823	$ (72)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Universal Unmetered Light (UUL)

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Witness: LMConnolly
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)		(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Line		Billing Determinants							Present					Proposed					
						Customer	Company		Customer Owned		Company Owned			Customer Owned		Company Owned			Net Increase
No.	Description	Customer	Company	Units	Watts	MWh	MWh		Production	Delivery	Production	Delivery	Revenue	Production	Delivery	Production	Delivery	Revenue	/ (Decrease)
									$/Light	$/Light	$/Light	$/Light	$000	$/Light	$/Light	$/Light	$/Light	$000	$000
1	15 - 24 Watts	12	-	Lights	20	0	-	@	0.28	7.29	0.28	10.29	$ 0	0.23	7.45	0.23	10.45	$ 0	$ 0
2	25 - 34 Watts	-	64,500	Lights	30	-	666	@	0.43	8.07	0.43	11.07	742	0.35	8.25	0.35	11.25	748	6
3	35 - 44 Watts	1,524	412,356	Lights	40	21	5,701	@	0.57	8.85	0.57	11.85	5,136	0.46	9.05	0.46	12.05	5,173	37
4	45 - 54 Watts	1,308	865,773	Lights	50	23	15,000	@	0.72	9.63	0.72	12.63	11,572	0.58	9.84	0.58	12.84	11,632	61
5	55 - 64 Watts	1,092	7,056	Lights	60	23	147	@	0.86	10.41	0.86	13.41	113	0.70	10.64	0.70	13.64	114	1
6	65 - 74 Watts	312	129,516	Lights	70	8	3,150	@	1.01	11.19	1.01	14.19	1,972	0.82	11.44	0.82	14.44	1,980	8
7	75 - 84 Watts	72	34,020	Lights	80	2	947	@	1.15	11.97	1.15	14.97	549	0.93	12.23	0.93	15.23	551	1
8	85 - 94 Watts	-	98,178	Lights	90	-	3,075	@	1.29	12.75	1.29	15.75	1,673	1.05	13.03	1.05	16.03	1,677	4
9	95 - 104 Watts	-	180	Lights	100	-	6	@	1.44	13.53	1.44	16.53	3	1.17	13.82	1.17	16.82	3	0
10	105 - 114 Watts	-	7,044	Lights	110	-	270	@	1.58	14.31	1.58	17.31	133	1.29	14.62	1.29	17.62	133	0
11	115 - 124 Watts	804	364,751	Lights	120	34	15,256	@	1.73	15.09	1.73	18.09	7,243	1.40	15.42	1.40	18.42	7,243	-
12	125 - 134 Watts	-	320	Lights	130	-	15	@	1.87	15.86	1.87	18.86	7	1.52	16.21	1.52	19.21	7	-
13	135 - 144 Watts	-	924	Lights	140	-	45	@	2.02	16.64	2.02	19.64	20	1.64	17.01	1.64	20.01	20	(0)
14	145 - 154 Watts	-	3,996	Lights	150	-	209	@	2.16	17.42	2.16	20.42	90	1.76	17.81	1.76	20.81	90	(0)
15	155 - 164 Watts	-	52	Lights	160	-	3	@	2.31	18.20	2.31	21.20	1	1.87	18.60	1.87	21.60	1	(0)
16	165 - 174 Watts	1,404	51,182	Lights	170	83	3,036	@	2.45	18.98	2.45	21.98	1,280	1.99	19.40	1.99	22.40	1,278	(2)
17	175 - 184 Watts	-	-	Lights	180	-	-	@	2.60	19.76	2.60	22.76	-	2.11	20.20	2.11	23.20	-	-
18	185 - 194 Watts	-	156	Lights	190	-	10	@	2.74	20.54	2.74	23.54	4	2.23	20.99	2.23	23.99	4	(0)
19	195 - 204 Watts	-	60	Lights	200	-	4	@	2.89	21.32	2.89	24.32	2	2.35	21.79	2.35	24.79	2	(0)
20	205 - 214 Watts	504	12,740	Lights	210	37	934	@	3.03	22.10	3.03	25.10	371	2.46	22.59	2.46	25.59	370	(1)
21	215 - 224 Watts	-	28	Lights	220	-	2	@	3.17	22.88	3.17	25.88	1	2.58	23.38	2.58	26.38	1	(0)
22	225 - 234 Watts	-	-	Lights	230	-	-	@	3.32	23.66	3.32	26.66	-	2.70	24.18	2.70	27.18	-	-
23	235 - 244 Watts	-	-	Lights	240	-	-	@	3.46	24.44	3.46	27.44	-	2.82	24.98	2.82	27.98	-	-
24	245 - 254 Watts	60	432	Lights	250	5	38	@	3.61	25.22	3.61	28.22	15	2.93	25.77	2.93	28.77	15	(0)
25	255 - 264 Watts	-	-	Lights	260	-	-	@	3.75	26.00	3.75	29.00	-	3.05	26.57	3.05	29.57	-	-
26	265 - 274 Watts	-	-	Lights	270	-	-	@	3.90	26.78	3.90	29.78	-	3.17	27.36	3.17	30.36	-	-
27	275 - 284 Watts	396	3,949	Lights	280	39	386	@	4.04	27.56	4.04	30.56	149	3.29	28.16	3.29	31.16	148	(1)
28	285 - 294 Watts	12	1,292	Lights	290	1	131	@	4.19	28.34	4.19	31.34	46	3.40	28.96	3.40	31.96	46	(0)
29	295 - 304 Watts	-	-	Lights	300	-	-	@	4.33	29.12	4.33	32.12	-	3.52	29.75	3.52	32.75	-	-
30	305 - 314 Watts	108	-	Lights	310	12	-	@	4.48	29.90	4.48	32.90	4	3.64	30.55	3.64	33.55	4	(0)
31	315 - 324 Watts	540	29,081	Lights	320	60	3,252	@	4.62	30.68	4.62	33.68	1,133	3.76	31.35	3.76	34.35	1,127	(6)
32	325 - 334 Watts	-	-	Lights	330	-	-	@	4.77	31.45	4.77	34.45	-	3.87	32.14	3.87	35.14	-	-
33	335 - 344 Watts	-	-	Lights	340	-	-	@	4.91	32.23	4.91	35.23	-	3.99	32.94	3.99	35.94	-	-
34	345 - 354 Watts	-	-	Lights	350	-	-	@	5.05	33.01	5.05	36.01	-	4.11	33.74	4.11	36.74	-	-
35	355 - 364 Watts	-	-	Lights	360	-	-	@	5.20	33.79	5.20	36.79	-	4.23	34.53	4.23	37.53	-	-
36	365 - 374 Watts	-	-	Lights	370	-	-	@	5.34	34.57	5.34	37.57	-	4.34	35.33	4.34	38.33	-	-
37	375 - 384 Watts	-	-	Lights	380	-	-	@	5.49	35.35	5.49	38.35	-	4.46	36.13	4.46	39.13	-	-
38	385 - 394 Watts	-	-	Lights	390	-	-	@	5.63	36.13	5.63	39.13	-	4.58	36.92	4.58	39.92	-	-
39	395 - 404 Watts	-	12	Lights	400	-	2	@	5.78	36.91	5.78	39.91	1	4.70	37.72	4.70	40.72	1	(0)
40	405 - 414 Watts	24	24	Lights	410	3	3	@	5.92	37.69	5.92	40.69	2	4.81	38.52	4.81	41.52	2	(0)
41	415 - 424 Watts	-	-	Lights	420	-	-	@	6.07	38.47	6.07	41.47	-	4.93	39.31	4.93	42.31	-	-
42	425 - 434 Watts	-	-	Lights	430	-	-	@	6.21	39.25	6.21	42.25	-	5.05	40.11	5.05	43.11	-	-
43	435 - 444 Watts	-	-	Lights	440	-	-	@	6.36	40.03	6.36	43.03	-	5.17	40.90	5.17	43.90	-	-
44	445 - 454 Watts	-	-	Lights	450	-	-	@	6.50	40.81	6.50	43.81	-	5.28	41.70	5.28	44.70	-	-
45	455 - 464 Watts	888	1,460	Lights	460	143	235	@	6.65	41.59	6.65	44.59	118	5.40	42.50	5.40	45.50	117	(1)
46	465 - 474 Watts	-	-	Lights	470	-	-	@	6.79	42.37	6.79	45.37	-	5.52	43.29	5.52	46.29	-	-
47	475 - 484 Watts	180	9,489	Lights	480	30	1,593	@	6.94	43.15	6.94	46.15	513	5.64	44.09	5.64	47.09	509	(3)
48	Conversion Credit	-	129,840	Lights								(7.72)	(1,002)				(7.72)	(1,002)	-
49	Annual PSCR Factor	9,240	2,098,571	Lights		524	54,116		0.009410		0.009410		514	0.009410		0.009410		514	-
50	Total Unmetered LED	9,240	2,098,571	Lights		524	54,116						$ 32,405					$ 32,509	$ 104

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Unmetered Service (GU)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
1	Non-capacity All kWh	99,352	MWh	@	0.037706	$ 3,746	0.025214	$ 2,505	$ (1,241)
2	Capacity All kWh	99,352	MWh	@	0.015927	1,582	0.018005	1,789	206
3	Annual PSCR Factor	99,352	MWh	@	0.009410	935	0.009410	935	-
4	Total Production					$ 6,264		$ 5,229	$ (1,035)
	Transmission								
5	All kWh	99,352	MWh	@	0.015085	1,499	0.015322	1,522	24
	Delivery								
6	System Access	5,578	Bills	@	2.00	$ 11	2.00	$ 11	$ -
7	Distribution	99,352	MWh	@	0.034452	3,423	0.034831	3,461	38
8	Total Delivery					$ 3,434		$ 3,472	$ 38
9	Total Full Service					$ 11,196		$ 10,223	$ (973)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Large Self-generation (GSG-2)

Case No.: U-22070
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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	STANDBY SERVICE								
	Production								
	Voltage Level 1								
1	On-peak kW-day	108	MW	@	11.57	$ 1,254	11.57	$ 1,254	$ -
2	All kWh	77,349	MWh	@	0.046132	3,568	0.046132	3,568	-
	Voltage Level 2								
3	On-peak kW-day	223	MW	@	11.73	2,613	11.73	2,613	-
4	All kWh	77,337	MWh	@	0.048126	3,722	0.048126	3,722	-
	Voltage Level 3								
5	On-peak kW-day	55	MW	@	11.91	650	11.91	650	-
6	All kWh	18,615	MWh	@	0.047120	877	0.047120	877	-
7	Power Factor Adjustment					261		261	-
8	Total Production					$ 12,946		$ 12,946	$ -
	Transmission								
	Voltage Level 1								
9	On-peak kW-day	108	MW	@	3.05	$ 330	3.05	$ 330	$ -
	Voltage Level 2								
10	On-peak kW-day	223	MW	@	3.09	688	3.09	688	-
	Voltage Level 3								
11	On-peak kW-day	55	MW	@	3.14	171	3.14	171	-
12	Total Transmission					$ 1,190		$ 1,190	$ -
	Delivery								
	System Access								
	Voltage Level 1								
13	Standby	64	Bills	@	100.00	$ 6	100.00	$ 6	$ -
14	Supplemental	-	Bills	@	100.00	-	100.00	-	-
15	Maximum kW	889	MW	@	2.37	2,110	0.85	755	(1,355)
16	Interconnect	355	MW	@	(2.37)	(842)	(0.85)	(301)	541
17	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
	Voltage Level 2								
18	Standby	94	Bills	@	100.00	$ 9	100.00	$ 9	$ -
19	Supplemental	-	Bills	@	100.00	-	100.00	-	-
20	Maximum kW	610	MW	@	3.61	2,203	3.69	2,250	47
21	Substation Ownership	288	MW	@	(1.93)	(555)	(1.93)	(555)	-
	Voltage Level 3								
22	Standby	13	Bills	@	100.00	$ 1	100.00	$ 1	$ -
23	Supplemental	-	Bills	@	100.00	-	100.00	-	-
24	Maximum kW	62	MW	@	6.68	412	6.87	424	12
25	Power Factor Adjustment					63		54	(9)
26	Total Delivery					$ 3,408		$ 2,642	$ (765)
27	Total Standby Service					$ 17,543		$ 16,778	$ (765)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response (DR) Surcharge

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Line No.	(a) Description	(b) Program plus Cust. Credits (1)	(c) Financial Incentive (1)	(d) Reconciled Balance (1)	(e) Total	(f) Units
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	0.001707	-	-	0.001707	per kWh
2	Smart Hours RSH	0.001707	-	-	0.001707	per kWh
3	Night Time Savers RPM	0.001707	-	-	0.001707	per kWh
4	Non-Transmitting Meters RSM	0.001707	-	-	0.001707	per kWh
	Secondary Class					
5	Energy-only GS	0.001552	-	-	0.001552	per kWh
6	Time-of-Use GSTU	0.001552	-	-	0.001552	per kWh
7	Demand GSD	0.52	-	-	0.52	per Peak kW
	Primary Class					
	Energy-only GP					
8	Voltage Level 1	0.001313	-	-	0.001313	per kWh
9	Voltage Level 2	0.001328	-	-	0.001328	per kWh
10	Voltage Level 3	0.001342	-	-	0.001342	per kWh
	Demand GPD					
11	Voltage Level 1	0.57	-	-	0.57	per On-Peak kW
12	Voltage Level 2	0.58	-	-	0.58	per On-Peak kW
13	Voltage Level 3	0.58	-	-	0.58	per On-Peak kW
14	Large Load	0.69	-	-	0.69	per On-Peak kW
	Time-of-Use GPTU					
15	Voltage Level 1	0.001188	-	-	0.001188	per kWh
16	Voltage Level 2	0.001202	-	-	0.001202	per kWh
17	Voltage Level 3	0.001214	-	-	0.001214	per kWh
	Energy Intensive EIP					
18	Voltage Level 1	0.000959	-	-	0.000959	per kWh
19	Voltage Level 2	0.000970	-	-	0.000970	per kWh
20	Voltage Level 3	0.000980	-	-	0.000980	per kWh
	Lighting & Unmetered Class					
21	Metered Lighting GML	0.000372	-	-	0.000372	per kWh
22	Universal Unmetered Lighting UUL	0.000347	-	-	0.000347	per kWh
23	Unmetered GU	0.001011	-	-	0.001011	per kWh
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	NA	NA	NA	NA	
25	Demand GSD	NA	NA	NA	NA	
	Primary Class					
	Energy-only GP					
26	Voltage Level 1	NA	NA	NA	NA	
27	Voltage Level 2	NA	NA	NA	NA	
28	Voltage Level 3	NA	NA	NA	NA	
	Demand GPD					
29	Voltage Level 1	NA	NA	NA	NA	
30	Voltage Level 2	NA	NA	NA	NA	
31	Voltage Level 3	NA	NA	NA	NA	

(1) WP-LMC-19

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Rate Case (ERC) Deferral Surcharge

Case No.: U-22070
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Line No.	Description	Test-year Sales (MWh)	ERC Deferral [1] ($000)	ERC Deferral Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 15,413	0.001215
	Secondary Class			
2	Energy-only GS	4,114,839	3,839	0.000933
3	Time-of-Use GSTU	84,563	79	0.000933
4	Demand GSD	2,979,606	2,139	0.000718
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	0	0.000043
6	Voltage Level 2	31,259	6	0.000179
7	Voltage Level 3	632,239	195	0.000308
	Demand GPD			
8	Voltage Level 1	1,167,540	30	0.000026
9	Voltage Level 2	1,453,040	157	0.000108
10	Voltage Level 3	2,414,780	449	0.000186
11	Large Load	7,884,000	205	0.000026
	Time-of-Use GPTU			
12	Voltage Level 1	464,518	12	0.000026
13	Voltage Level 2	496,642	54	0.000108
14	Voltage Level 3	3,312,240	616	0.000186
	Energy Intensive EIP			
15	Voltage Level 1	332,592	9	0.000026
16	Voltage Level 2	53,237	6	0.000108
17	Voltage Level 3	6,737	1	0.000186
	Lighting & Unmetered Class			
18	Metered Lighting GML	10,776	15	0.001397
19	Universal Unmetered Lighting UUL	54,640	342	0.006258
20	Unmetered GU	99,352	40	0.000399
	Self-generation Class			
21	Large Self-generation GSG-2			
22	Voltage Level 1	77,349	2	0.000026
23	Voltage Level 2	77,337	8	0.000108
24	Voltage Level 3	18,615	3	0.000186
25	Total Full Service		$ 23,620	

Line No.	Description	Test-year Sales (MWh)	ERC Deferral [1] ($000)	ERC Deferral Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001215
	Secondary Class			
2	Energy-only GS	18,702	17	0.000933
3	Time-of-Use GSTU	-	-	0.000933
4	Demand GSD	174,288	125	0.000718
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000043
6	Voltage Level 2	1,783	0	0.000179
7	Voltage Level 3	70,285	22	0.000308
	Demand GPD			
8	Voltage Level 1	1,270,576	33	0.000026
9	Voltage Level 2	1,080,207	117	0.000108
10	Voltage Level 3	953,091	177	0.000186
11	Total ROA Service		$ 492	
12	Total Surcharge Revenue Collected		$ 24,111	
13	Rounding		26	
14	Total Surcharge Revenue Target		$ 24,137	

[1] A-89 (EAD-5), line 12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 1 - 12 months ending April 30, 2027

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Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue [1] ($000)	(d) IRM Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 8,829	0.000696
	Secondary Class			
2	Energy-only GS	4,114,839	2,197	0.000534
3	Time-of-Use GSTU	84,563	45	0.000534
4	Demand GSD	2,979,606	1,225	0.000411
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	0	0.000089
6	Voltage Level 2	31,259	3	0.000101
7	Voltage Level 3	632,239	111	0.000175
	Demand GPD			
8	Voltage Level 1	1,167,540	50	0.000043
9	Voltage Level 2	1,453,040	71	0.000049
10	Voltage Level 3	2,414,780	203	0.000084
11	Large Load	7,884,000	339	0.000043
	Time-of-Use GPTU			
12	Voltage Level 1	464,518	20	0.000043
13	Voltage Level 2	496,642	24	0.000049
14	Voltage Level 3	3,312,240	278	0.000084
	Energy Intensive EIP			
15	Voltage Level 1	332,592	14	0.000043
16	Voltage Level 2	53,237	3	0.000049
17	Voltage Level 3	6,737	1	0.000084
	Lighting & Unmetered Class			
18	Metered Lighting GML	10,776	9	0.000800
19	Universal Unmetered Lighting UUL	54,640	196	0.003583
20	Unmetered GU	99,352	23	0.000229
	Self-generation Class			
21	Large Self-generation GSG-2			
22	Voltage Level 1	77,349	3	0.000043
23	Voltage Level 2	77,337	4	0.000049
24	Voltage Level 3	18,615	2	0.000084
25	Total Full Service		$ 13,649	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue [1] ($000)	(h) IRM Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.000696
	Secondary Class			
2	Energy-only GS	18,702	10	0.000534
3	Time-of-Use GSTU	-	-	0.000534
4	Demand GSD	174,288	72	0.000411
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000089
6	Voltage Level 2	1,783	0	0.000101
7	Voltage Level 3	70,285	12	0.000175
	Demand GPD			
8	Voltage Level 1	1,270,576	55	0.000043
9	Voltage Level 2	1,080,207	53	0.000049
10	Voltage Level 3	953,091	80	0.000084
11	Total ROA Service		$ 282	
12	Total Surcharge Revenue Collected		$ 13,931	
13	Rounding		(4)	
14	Total Surcharge Revenue Target		$ 13,927	

(1) A-89 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 2 - 12 months ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-66 (LMC-3)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue [1] ($000)	(d) IRM Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 16,212	0.001278
	Secondary Class			
2	Energy-only GS	4,114,839	4,041	0.000982
3	Time-of-Use GSTU	84,563	83	0.000982
4	Demand GSD	2,979,606	2,253	0.000756
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	1	0.000164
6	Voltage Level 2	31,259	10	0.000322
7	Voltage Level 3	632,239	204	0.000322
	Demand GPD			
8	Voltage Level 1	1,167,540	84	0.000072
9	Voltage Level 2	1,453,040	205	0.000141
10	Voltage Level 3	2,414,780	340	0.000141
11	Large Load	7,884,000	568	0.000072
	Time-of-Use GPTU			
12	Voltage Level 1	464,518	33	0.000072
13	Voltage Level 2	496,642	70	0.000141
14	Voltage Level 3	3,312,240	467	0.000141
	Energy Intensive EIP			
15	Voltage Level 1	332,592	24	0.000072
16	Voltage Level 2	53,237	8	0.000141
17	Voltage Level 3	6,737	1	0.000141
	Lighting & Unmetered Class			
18	Metered Lighting GML	10,776	16	0.001470
19	Universal Unmetered Lighting UUL	54,640	360	0.006585
20	Unmetered GU	99,352	42	0.000420
	Self-generation Class			
21	Large Self-generation GSG-2			
22	Voltage Level 1	77,349	6	0.000072
23	Voltage Level 2	77,337	11	0.000141
24	Voltage Level 3	18,615	3	0.000141
25	Total Full Service		$ 25,039	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue [1] ($000)	(h) IRM Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001278
	Secondary Class			
2	Energy-only GS	18,702	18	0.000982
3	Time-of-Use GSTU	-	-	0.000982
4	Demand GSD	174,288	132	0.000756
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000164
6	Voltage Level 2	1,783	1	0.000322
7	Voltage Level 3	70,285	23	0.000322
	Demand GPD			
8	Voltage Level 1	1,270,576	91	0.000072
9	Voltage Level 2	1,080,207	152	0.000141
10	Voltage Level 3	953,091	134	0.000141
11	Total ROA Service		$ 552	
12	Total Surcharge Revenue Collected		$ 25,591	
13	Rounding		6	
14	Total Surcharge Revenue Target		$ 25,597	

(1) A-89 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Total Revenues

Proposal 3

U-21870 Final Order Model

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Customers	Sales	Revenue		Net Increase / (Decrease)	
				Present	Proposed	Revenue	Percent
		Mthly	MWh	$000	$000	$000	%
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	1,628,594	12,230,766	$ 2,530,673	$ 2,383,734	$ (146,939)	(5.8)
2	Smart Hours RSH	24,351	177,999	36,984	34,843	(2,142)	(5.8)
3	Night Time Savers RPM	16,879	168,382	34,132	32,161	(1,971)	(5.8)
4	Non-Transmitting Meters RSM	10,973	108,263	23,269	21,992	(1,277)	(5.5)
5	Total Residential Class	1,680,798	12,685,410	$ 2,625,059	$ 2,472,730	$ (152,329)	(5.8)
	Secondary Class						
6	Energy-only GS	204,973	4,114,839	$ 742,820	$ 703,513	$ (39,307)	(5.3)
7	Time-of-Use GSTU	1,891	84,563	15,240	14,360	(880)	(5.8)
8	Demand GSD	20,152	2,979,606	467,203	440,388	(26,815)	(5.7)
9	Total Secondary	227,015	7,179,008	$ 1,225,264	$ 1,158,261	$ (67,002)	(5.5)
	Primary Class						
10	Energy-only GP	1,360	666,952	$ 78,703	$ 73,683	$ (5,019)	(6.4)
11	Demand GPD	855	5,035,360	455,727	423,007	(32,720)	(7.2)
12	Large Load	1	7,884,000	-	556,038	556,038	NA
13	Time-of-Use GPTU	1,517	4,273,401	448,037	417,752	(30,284)	(6.8)
14	Energy Intensive EIP	17	392,565	30,168	27,366	(2,802)	(9.3)
15	Total Primary	3,749	18,252,279	$ 1,012,633	$ 1,497,846	$ 485,213	47.9
	Lighting & Unmetered Class						
16	Metered Lighting GML	399	10,776	$ 1,895	$ 1,977	$ 82	4.3
17	Universal Unmetered Lighting UUL	4,696	54,640	32,405	33,290	885	2.7
18	Unmetered GU	465	99,352	11,196	10,654	(543)	(4.8)
19	Total Lighting & Unmetered	5,560	164,769	$ 45,496	$ 45,920	$ 424	0.9
	Self-generation Class						
20	Small Self-generation GSG-1	-	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	14	173,301	17,543	16,789	(754)	(4.3)
22	Total Self-generation	14	173,301	$ 17,543	$ 16,789	$ (754)	(4.3)
23	Total Full Service	1,917,136	38,454,766	$ 4,925,995	$ 5,191,546	$ 265,551	5.4
	ROA SERVICE						
	Secondary Class						
24	Energy-only GS	85	18,702	$ 1,307	$ 1,344	$ 37	2.8
25	Demand GSD	472	174,288	10,522	10,744	222	2.1
26	Total Secondary	556	192,989	$ 11,829	$ 12,088	$ 259	2.2
	Primary Class						
27	Energy-only GP	60	72,068	$ 1,792	$ 1,848	$ 56	3.1
28	Demand GPD	356	3,303,873	30,936	28,149	(2,787)	(9.0)
29	Total Primary	417	3,375,942	$ 32,727	$ 29,997	$ (2,731)	(8.3)
30	Total ROA Service	973	3,568,931	$ 44,557	$ 42,085	$ (2,472)	(5.5)
31	Total Jurisdictional Service	1,918,109	42,023,697	$ 4,970,552	$ 5,233,631	$ 263,080	5.3
32	Plus: Rounding			-	345	(345)	
33	Total Jurisdictional Revenues			$ 4,970,552	$ 5,233,977	$ 263,425	5.3
34	Less: PSCR Factor Revenues			299,823	374,011	74,188	
35	Less: DR Surcharge			-	51,821	51,821	
36	Less: IRM Surcharge			-	13,927	13,927	
37	Total Jurisdictional Base Revenues			$ 4,670,729	$ 4,794,217	$ 123,488	2.6
38	Total Jurisdictional Revenues			4,970,552	5,233,977	263,425	5.3
39	Plus: ERC Deferral Surcharge			-	24,111	24,111	
40	Total Jurisdictional Revenues Requested			$ 4,970,552	$ 5,258,088	$ 287,536	5.8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Production & Transmission Revenues

Proposal 3

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Sales	Revenue Present	Revenue Proposed	Net Increase / (Decrease) Revenue	Net Increase / (Decrease) Percent
	(a)	(b)	(c)	(d)	(e)	(f)
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,230,766	$ 1,259,128	$ 1,088,762	$ (170,366)	(13.5)
2	Smart Hours RSH	177,999	18,333	15,850	(2,483)	(13.5)
3	Night Time Savers RPM	168,382	17,006	14,713	(2,293)	(13.5)
4	Non-Transmitting Meters RSM	108,263	11,022	9,537	(1,485)	(13.5)
5	Total Residential Class	12,685,410	$ 1,305,488	$ 1,128,861	$ (176,627)	(13.5)
	Secondary Class					
6	Energy-only GS	4,114,839	$ 408,019	$ 360,786	$ (47,233)	(11.6)
7	Time-of-Use GSTU	84,563	8,915	7,872	(1,042)	(11.7)
8	Demand GSD	2,979,606	279,797	249,264	(30,533)	(10.9)
9	Total Secondary	7,179,008	$ 696,731	$ 617,922	$ (78,809)	(11.3)
	Primary Class					
10	Energy-only GP	666,952	$ 61,147	$ 55,642	$ (5,504)	(9.0)
11	Demand GPD	5,035,360	397,720	367,132	(30,588)	(7.7)
12	Large Load	7,884,000	-	528,547	528,547	NA
13	Time-of-Use GPTU	4,273,401	367,811	337,122	(30,689)	(8.3)
14	Energy Intensive EIP	392,565	27,016	25,335	(1,681)	(6.2)
15	Total Primary	18,252,279	$ 853,693	$ 1,313,778	$ 460,085	53.9
	Lighting & Unmetered Class					
16	Metered Lighting GML	10,776	$ 579	$ 640	$ 61	10.5
17	Universal Unmetered Lighting UUL	54,640	2,776	2,929	153	5.5
18	Unmetered GU	99,352	7,762	7,159	(603)	(7.8)
19	Total Lighting & Unmetered	164,769	$ 11,117	$ 10,728	$ (389)	(3.5)
	Self-generation Class					
20	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	173,301	14,136	14,136	-	-
22	Total Self-generation	173,301	$ 14,136	$ 14,136	$ -	-
23	Total Full Service	38,454,766	$ 2,881,165	$ 3,085,426	$ 204,260	7.1
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	-	$ -	$ -	$ -	NA
25	Demand GSD	-	-	-	-	NA
26	Total Secondary	-	$ -	$ -	$ -	NA
	Primary Class					
27	Energy-only GP	-	$ -	$ -	$ -	NA
28	Demand GPD	-	-	-	-	NA
29	Total Primary	-	$ -	$ -	$ -	NA
30	Total ROA Service	-	$ -	$ -	$ -	NA
31	Total Jurisdictional Service	38,454,766	$ 2,881,165	$ 3,085,426	$ 204,260	7.1
32	Plus: Rounding		-	8,410	8,410	
33	Total Jurisdictional Base Revenues		$ 2,881,165	$ 3,093,836	$ 212,670	7.4
34	Less: PSCR Factor Revenues		299,823	374,011	74,188	
35	Less: DR Surcharge		-	51,821	51,821	
36	Less: IRM Surcharge		-	-	-	
37	Total Jurisdictional Base Revenues		$ 2,581,342	$ 2,668,003	$ 86,660	3.4
38	Total Jurisdictional Revenues		2,881,165	3,093,836	212,670	7.4
39	Plus: ERC Deferral Surcharge		-	-	-	
40	Total Jurisdictional Revenues Requested		$ 2,881,165	$ 3,093,836	$ 212,670	7.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Delivery Revenues

Proposal 3

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Sales	(c) Revenue Present	(d) Revenue Proposed	(e) Net Increase / (Decrease) Revenue	(f) Net Increase / (Decrease) Percent
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,230,766	$ 1,271,545	$ 1,294,972	$ 23,427	1.8
2	Smart Hours RSH	177,999	18,652	18,993	341	1.8
3	Night Time Savers RPM	168,382	17,126	17,448	323	1.9
4	Non-Transmitting Meters RSM	108,263	12,248	12,455	207	1.7
5	Total Residential Class	12,685,410	$ 1,319,571	$ 1,343,868	$ 24,298	1.8
	Secondary Class					
6	Energy-only GS	4,114,839	$ 334,801	$ 342,728	$ 7,926	2.4
7	Time-of-Use GSTU	84,563	6,325	6,488	163	2.6
8	Demand GSD	2,979,606	187,406	191,124	3,718	2.0
9	Total Secondary	7,179,008	$ 528,533	$ 540,339	$ 11,807	2.2
	Primary Class					
10	Energy-only GP	666,952	$ 17,556	$ 18,041	$ 485	2.8
11	Demand GPD	5,035,360	58,006	55,875	(2,132)	(3.7)
12	Large Load	7,884,000	-	19,085	19,085	NA
13	Time-of-Use GPTU	4,273,401	80,226	80,631	405	0.5
14	Energy Intensive EIP	392,565	3,152	2,031	(1,121)	(35.6)
15	Total Primary	18,252,279	$ 158,940	$ 175,663	$ 16,723	10.5
	Lighting & Unmetered Class					
16	Metered Lighting GML	10,776	$ 1,316	$ 1,337	$ 21	1.6
17	Universal Unmetered Lighting UUL	54,640	29,629	30,360	732	2.5
18	Unmetered GU	99,352	3,434	3,494	60	1.8
19	Total Lighting & Unmetered	164,769	$ 34,379	$ 35,192	$ 813	2.4
	Self-generation Class					
20	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	173,301	3,408	2,654	(754)	(22.1)
22	Total Self-generation	173,301	$ 3,408	$ 2,654	$ (754)	(22.1)
23	Total Full Service	38,454,766	$ 2,044,829	$ 2,097,716	$ 52,886	2.6
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	18,702	$ 1,307	$ 1,344	$ 37	2.8
25	Demand GSD	174,288	10,522	10,744	222	2.1
26	Total Secondary	192,989	$ 11,829	$ 12,088	$ 259	2.2
	Primary Class					
27	Energy-only GP	72,068	$ 1,792	$ 1,848	$ 56	3.1
28	Demand GPD	3,303,873	30,936	28,149	(2,787)	(9.0)
29	Total Primary	3,375,942	$ 32,727	$ 29,997	$ (2,731)	(8.3)
30	Total ROA Service	3,568,931	$ 44,557	$ 42,085	$ (2,472)	(5.5)
31	Total Jurisdictional Service	42,023,697	$ 2,089,386	$ 2,139,801	$ 50,415	2.4
32	Plus: Rounding		-	340	340	
33	Total Jurisdictional Base Revenues		$ 2,089,386	$ 2,140,141	$ 50,755	2.4
34	Less: PSCR Factor Revenues		-	-	-	
35	Less: DR Surcharge		-	-	-	
36	Less: IRM Surcharge		-	13,927	13,927	
37	Total Jurisdictional Base Revenues		$ 2,089,386	$ 2,126,214	$ 36,828	1.8
38	Total Jurisdictional Revenues		2,089,386	2,140,141	50,755	2.4
39	Plus: ERC Deferral Surcharge		-	24,111	24,111	
40	Total Jurisdictional Revenues Requested		$ 2,089,386	$ 2,164,252	$ 74,866	3.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Rate Design Targets
($000)

Proposal 3

U-21870 Final Order Model

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Jurisdictional	(c) Residential	(d) Secondary Class GS	(e) Secondary Class GSD	(f) Primary Class GP	(g) Primary Class GPD	(h) Primary Class LL	(i) Primary Class GPTU	(j) Primary Class EIP	(k) Lighting & Unmetered Class GML	(l) Lighting & Unmetered Class UUL	(m) Lighting & Unmetered Class GU	(n) Self Gen. Class GSG-1	(o) Self Gen. Class GSG-2	Source
	Production															
1	Capacity (SRM)	$ 1,105,401	$ 438,413	$ 137,846	$ 90,254	$ 20,015	$ 121,906	$ 164,866	$ 116,528	$ 9,080	$ 164	$ 632	$ 2,211	$ -	$ 3,485	
	Capacity Adjustments [1]															
2	DR Revenue Requirement	(43,454)	(16,667)	(5,302)	(3,538)	(780)	(4,958)	(7,048)	(4,647)	(377)	(8)	(35)	(94)	-	-	WP-LMC-57
3	Self Generation	-	1,246	392	257	57	346	469	331	26	0	2	6	-	(3,132)	Alloc. Line 1
4	Total Adjustments	(43,454)	(15,421)	(4,910)	(3,282)	(723)	(4,612)	(6,579)	(4,316)	(351)	(8)	(33)	(88)	-	(3,132)	
5	Capacity (SRM) Design Target	$ 1,061,947	$ 422,992	$ 132,936	$ 86,972	$ 19,292	$ 117,294	$ 158,286	$ 112,213	$ 8,728	$ 157	$ 599	$ 2,123	$ -	$ 353	
6	Energy [2]	$ 855,908	$ 270,053	$ 96,161	$ 69,392	$ 15,555	$ 116,501	$ 184,827	$ 100,156	$ 9,651	$ 262	$ 1,361	$ 2,496	$ -	$ (10,506)	
	Energy Adjustments [1]															
7	Self Generation	-	(3,275)	(1,166)	(841)	(189)	(1,413)	(2,241)	(1,214)	(117)	(3)	(16)	(30)	-	10,506	Alloc. Line 6
8	Total Adjustments	-	(3,275)	(1,166)	(841)	(189)	(1,413)	(2,241)	(1,214)	(117)	(3)	(16)	(30)	-	10,506	
9	Energy Design Target	$ 855,908	$ 266,778	$ 94,995	$ 68,551	$ 15,366	$ 115,088	$ 182,586	$ 98,942	$ 9,534	$ 259	$ 1,344	$ 2,466	$ -	$ -	
10	Total Production	$ 1,917,855	$ 689,770	$ 227,931	$ 155,523	$ 34,658	$ 232,382	$ 340,872	$ 211,154	$ 18,263	$ 416	$ 1,943	$ 4,589	$ -	$ 353	
11	**Transmission**															
12	Transmission	758,515	300,835	94,589	61,931	13,734	83,651	113,129	79,960	6,230	113	434	1,518	-	2,391	
13	Self Generation	-	951	299	196	43	265	358	253	20	0	1	5	-	(2,391)	Alloc. Line 12
14	Transmission Design Target	$ 758,515	$ 301,786	$ 94,888	$ 62,127	$ 13,778	$ 83,915	$ 113,487	$ 80,213	$ 6,250	$ 113	$ 435	$ 1,522	$ -	$ -	
	Delivery															
15	Distribution [3]	$ 1,877,265	$ 1,159,835	$ 308,197	$ 188,863	$ 16,459	$ 82,580	$ 15,270	$ 69,451	$ 1,193	$ 1,240	$ 28,563	$ 3,384	$ -	$ 2,229	
16	Customer	248,945	187,288	35,884	9,078	2,929	5,350	1,126	5,601	112	76	1,324	82	-	95	
17	Subtotal Delivery	2,126,210	1,347,123	344,081	197,941	19,388	87,930	16,396	75,052	1,304	1,316	29,887	3,466	-	2,324	
	Credit Adjustments [4]															
18	Substation Credits	$ -	$ 1,792	$ 476	$ 292	$ (8)	$ (1,400)	$ 24	$ (346)	$ (323)	$ 2	$ 44	$ 5	$ -	$ (558)	WP-LMC-62
19	Life Line Credits	0	(13,876)	3,751	2,339	382	2,281	2,665	2,067	146	10	235	-	-	-	WP-LMC-59
20	Total Adjustments	0	(12,084)	4,227	2,630	374	881	2,689	1,722	(177)	12	279	5	-	(558)	
21	Total Delivery Design Target	$ 2,126,210	$ 1,335,039	$ 348,307	$ 200,571	$ 19,762	$ 88,811	$ 19,085	$ 76,774	$ 1,127	$ 1,328	$ 30,166	$ 3,472	$ -	$ 1,766	
22	Total Rate Design Target	$ 4,802,580	$ 2,326,595	$ 671,126	$ 418,222	$ 68,198	$ 405,109	$ 473,444	$ 368,141	$ 25,640	$ 1,857	$ 32,544	$ 9,583	$ -	$ 2,119	
23	DR Surcharge	$ 51,821	$ 19,876	$ 6,323	$ 4,220	$ 930	$ 5,913	$ 8,405	$ 5,541	$ 449	$ 10	$ 41	$ 113	$ -	$ -	WP-LMC-69
24	IRM Surcharge	$ 13,931	$ 8,829	$ 2,252	$ 1,296	$ 127	$ 512	$ 339	$ 323	$ 17	$ 9	$ 196	$ 23	$ -	$ 9	A-68 (LMC-7)
25	Total Revenue Requirement	$ 4,868,332	$ 2,355,300	$ 679,701	$ 423,738	$ 69,255	$ 411,534	$ 482,188	$ 374,005	$ 26,107	$ 1,875	$ 32,782	$ 9,719	$ -	$ 2,128	

Notes
(1) Capacity and energy production costs adjusted to capture elements occurring outside the Cost-of-Service Study.
(2) Includes Non-SRM capacity related costs.
(3) Excludes IRM costs recovered through the IRM surcharge.
(4) Credit adjustments approved in Case No. U-21389

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Summer On-peak (RSP)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	814,657	MWh	@	0.060410	$ 49,214	0.034110	$ 27,788	$ (21,426)
2	Off-peak kWh	3,560,451	MWh	@	0.041347	147,215	0.023346	83,123	(64,092)
	Capacity								
3	On-peak kWh	814,657	MWh	@	0.053506	43,589	0.054084	44,060	470
4	Off-peak kWh	3,560,451	MWh	@	0.036622	130,390	0.037017	131,797	1,407
	Winter (Oct. - May)								
5	Non-capacity All kWh	7,855,392	MWh	@	0.033007	259,279	0.018637	146,399	(112,880)
6	Capacity All kWh	7,855,392	MWh	@	0.029234	229,647	0.029550	232,125	2,478
	Provisions								
	Device Cycling								
7	AC Cycling(1)	270,897	Bills	@	(5.00)	(1,354)	(5.00)	(1,354)	-
8	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
9	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
10	Peak Time Rewards	1,016	MWh	@	(0.50)	(508)	(0.50)	(508)	-
	Critical Peak Pricing								
11	Critical-peak Charge	266	MWh	@	1.00	266	1.00	266	-
12	Off-peak Credits	41,754	MWh	@	(0.006373)	(266)	(0.006373)	(266)	-
13	Annual PSCR Factor	12,230,766	MWh	@	0.009410	115,092	0.009410	115,092	-
14	Total Production					$ 972,564		$ 778,522	$ (194,042)
	Transmission								
	Summer (June - Sept.)								
15	On-peak kWh	814,657	MWh	@	0.037988	$ 30,947	0.038586	$ 31,434	$ 487
16	Off-peak kWh	3,560,451	MWh	@	0.026001	92,574	0.026410	94,031	1,458
	Winter (Oct. - May)								
17	All kWh	7,855,392	MWh	@	0.020756	163,043	0.021082	165,611	2,567
18	Total Transmission					$ 286,564		$ 291,077	$ 4,513
	Delivery								
19	System Access	19,543,128	Bills	@	8.00	$ 156,345	8.00	$ 156,345	$ -
20	Distribution	12,230,766	MWh	@	0.093333	1,141,532	0.094552	1,156,446	14,914
	Provisions								
21	Senior Citizen (RSC)	4,444,922	Bills	@	(4.00)	(17,780)	(4.00)	(17,780)	-
22	Low Income Credit (LIAC)	66,396	Bills	@	(42.00)	(2,789)	(42.00)	(2,789)	-
23	Income Assistance (RIA)	720,358	Bills	@	(8.00)	(5,763)	(8.00)	(5,763)	-
24	Total Delivery					$ 1,271,545		$ 1,286,460	$ 14,914
25	Total Full Service					$ 2,530,673		$ 2,356,058	$ (174,616)
	ROA SERVICE								
	Delivery								
26	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
27	Distribution	-	MWh	@	0.093333	-	0.094552	-	-
	Provisions								
28	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
29	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
30	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
31	Total Delivery					$ -		$ -	$ -
32	Total Full & ROA Service					$ 2,530,673		$ 2,356,058	$ (174,616)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Smart Hours (RSH)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 6 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	11,637	MWh	@	0.060410	$ 703	0.034110	$ 397	$ (306)
2	Off-peak kWh	54,082	MWh	@	0.041347	2,236	0.023346	1,263	(974)
	Capacity								
3	On-peak kWh	11,637	MWh	@	0.053506	623	0.054084	629	7
4	Off-peak kWh	54,082	MWh	@	0.036622	1,981	0.037017	2,002	21
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kWh	17,187	MWh	@	0.038335	659	0.021646	372	(287)
6	Off-peak kWh	95,088	MWh	@	0.031989	3,042	0.018062	1,717	(1,324)
	Capacity								
7	On-peak kWh	17,187	MWh	@	0.033954	584	0.034320	590	6
8	Off-peak kWh	95,088	MWh	@	0.028333	2,694	0.028639	2,723	29
	Provisions								
	Device Cycling								
9	AC Cycling(1)	3,816	Bills	@	(5.00)	(19)	(5.00)	(19)	-
10	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
11	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
12	Peak Time Rewards	30	MWh	@	(0.50)	(15)	(0.50)	(15)	-
	Critical Peak Pricing								
13	Critical-peak Charge	5	MWh	@	1.00	5	1.00	5	-
14	Off-peak Credits	1,456	MWh	@	(0.006373)	(9)	(0.006373)	(9)	-
15	Annual PSCR Factor	177,999	MWh	@	0.009410	1,675	0.009410	1,675	-
16	Total Production					$ 14,157		$ 11,330	$ (2,827)
	Transmission								
	Summer (June - Sept.)								
17	On-peak kWh	11,637	MWh	@	0.037988	$ 442	0.038586	$ 449	$ 7
18	Off-peak kWh	54,082	MWh	@	0.026001	1,406	0.026410	1,428	22
	Winter (Oct. - May)								
19	On-peak kWh	17,187	MWh	@	0.024106	414	0.024486	421	7
20	Off-peak kWh	95,088	MWh	@	0.020116	1,913	0.020432	1,943	30
21	Total Transmission					$ 4,175		$ 4,241	$ 66
	Delivery								
22	System Access	292,217	Bills	@	8.00	$ 2,338	8.00	$ 2,338	$ -
23	Distribution	177,999	MWh	@	0.093333	16,613	0.094552	16,830	217
	Provisions								
24	Senior Citizen (RSC)	48,048	Bills	@	(4.00)	(192)	(4.00)	(192)	-
25	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	13,378	Bills	@	(8.00)	(107)	(8.00)	(107)	-
27	Total Delivery					$ 18,652		$ 18,869	$ 217
28	Total Full Service					$ 36,984		$ 34,440	$ (2,544)
	ROA SERVICE								
	Delivery								
29	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
30	Distribution	-	MWh	@	0.093333	-	0.094552	-	-
	Provisions								
31	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
32	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
34	Total Delivery					$ -		$ -	$ -
35	Total Full & ROA Service					$ 36,984		$ 34,440	$ (2,544)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Nighttime Savers (RPM)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 7 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	9,384	MWh	@	0.060410	$ 567	0.034110	$ 320	$ (247)
2	Off-peak kWh	19,685	MWh	@	0.046196	909	0.026084	513	(396)
3	Super Off-peak kWh	33,466	MWh	@	0.037381	1,251	0.021107	706	(545)
	Capacity								
4	On-peak kWh	9,384	MWh	@	0.053506	502	0.054084	507	5
5	Off-peak kWh	19,685	MWh	@	0.040916	805	0.041358	814	9
6	Super Off-peak kWh	33,466	MWh	@	0.033109	1,108	0.033466	1,120	12
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	13,591	MWh	@	0.038335	521	0.021646	294	(227)
8	Off-peak kWh	33,262	MWh	@	0.035960	1,196	0.020305	675	(521)
9	Super Off-peak kWh	58,994	MWh	@	0.028890	1,704	0.016313	962	(742)
	Capacity								
10	On-peak kWh	13,591	MWh	@	0.033954	461	0.034320	466	5
11	Off-peak kWh	33,262	MWh	@	0.031850	1,059	0.032194	1,071	11
12	Super Off-peak kWh	58,994	MWh	@	0.025588	1,510	0.025865	1,526	16
	Provisions								
	Device Cycling								
13	AC Cycling(1)	4,141	Bills	@	(5.00)	(21)	(5.00)	(21)	-
14	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
15	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
16	Peak Time Rewards	23	MWh	@	(0.50)	(11)	(0.50)	(11)	-
	Critical Peak Pricing								
17	Critical-peak Charge	1	MWh	@	1.00	1	1.00	1	-
18	Off-peak Credits	1,417	MWh	@	(0.006373)	(9)	(0.006373)	(9)	-
19	Annual PSCR Factor	168,382	MWh	@	0.009410	1,584	0.009410	1,584	-
20	Total Production					$ 13,139		$ 10,521	$ (2,618)
	Transmission								
	Summer (June - Sept.)								
21	On-peak kWh	9,384	MWh	@	0.037988	$ 356	0.038586	$ 362	$ 6
22	Off-peak kWh	19,685	MWh	@	0.029049	572	0.029507	581	9
23	Super Off-peak kWh	33,466	MWh	@	0.023506	787	0.023876	799	12
	Winter (Oct. - May)								
24	On-peak kWh	13,591	MWh	@	0.024106	328	0.024486	333	5
25	Off-peak kWh	33,262	MWh	@	0.022613	752	0.022969	764	12
26	Super Off-peak kWh	58,994	MWh	@	0.018167	1,072	0.018453	1,089	17
27	Total Transmission					$ 3,866		$ 3,927	$ 61
	Delivery								
28	System Access	202,551	Bills	@	8.00	$ 1,620	8.00	$ 1,620	$ -
29	Separately Metered EV Charger	295	Bills	@	(8.00)	$ (2)	(8.00)	$ (2)	$ -
30	Distribution	168,382	MWh	@	0.093333	15,716	0.094552	15,921	205
	Provisions								
31	Senior Citizen (RSC)	41,852	Bills	@	(4.00)	(167)	(4.00)	(167)	-
32	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	5,053	Bills	@	(8.00)	(40)	(8.00)	(40)	-
34	Total Delivery					$ 17,126		$ 17,331	$ 205
35	Total Full Service					$ 34,132		$ 31,780	$ (2,352)
	ROA SERVICE								
	Delivery								
36	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
37	Distribution	-	MWh	@	0.093333	-	0.094552	-	-
	Provisions								
38	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
39	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
40	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
41	Total Delivery					$ -		$ -	$ -
42	Total Full & ROA Service					$ 34,132		$ 31,780	$ (2,352)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Non-Transmitting Meters (RSM)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 8 of 32
Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	First 600 kWh	23,089	MWh	@	0.033007	$ 762	0.018637	$ 430	$ (332)
2	Excess kWh	14,767	MWh	@	0.060410	892	0.034110	504	(388)
	Capacity								
3	First 600 kWh	23,089	MWh	@	0.029234	675	0.029550	682	7
4	Excess kWh	14,767	MWh	@	0.053506	790	0.054084	799	9
	Winter (Oct. - May)								
5	Non-capacity All kWh	70,407	MWh	@	0.033007	2,324	0.018637	1,312	(1,012)
6	Capacity All kWh	70,407	MWh	@	0.029234	2,058	0.029550	2,081	22
7	Annual PSCR Factor	108,263	MWh	@	0.009410	1,019	0.009410	1,019	-
8	Total Production					$ 8,520		$ 6,826	$ (1,694)
	Transmission								
	Summer (June - Sept.)								
9	First 600 kWh	23,089	MWh	@	0.020756	$ 479	0.021082	$ 487	$ 8
10	Excess kWh	14,767	MWh	@	0.037988	561	0.038586	570	9
	Winter (Oct. - May)								
11	All kWh	70,407	MWh	@	0.020756	1,461	0.021082	1,484	23
12	Total Transmission					$ 2,502		$ 2,541	$ 39
	Delivery								
13	System Access	131,680	Bills	@	8.00	$ 1,053	8.00	$ 1,053	$ -
14	Opt-out Fee	100,852	Bills	@	12.61	1,272	12.61	1,272	-
15	Distribution	108,263	MWh	@	0.093333	10,104	0.094552	10,236	132
	Provisions								
16	Senior Citizen (RSC)	36,309	Bills	@	(4.00)	(145)	(4.00)	(145)	-
17	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
18	Income Assistance (RIA)	4,599	Bills	@	(8.00)	(37)	(8.00)	(37)	-
19	Total Delivery					$ 12,248		$ 12,380	$ 132
20	Total Full Service					$ 23,269		$ 21,747	$ (1,522)
	ROA SERVICE								
	Delivery								
21	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
22	Opt-out Fee	-	Bills	@	12.61	-	12.61	-	-
23	Distribution	-	MWh	@	0.093333	-	0.094552	-	-
	Provisions								
24	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
25	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
27	Total Delivery					$ -		$ -	$ -
28	Total Full & ROA Service					$ 23,269		$ 21,747	$ (1,522)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Energy-only (GS)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 9 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c)	(d) Present Rate $/unit	(e) Revenue $000	(f) Proposed Rate $/unit	(g) Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE									
	Production									
	Summer (June - Sept.)									
1	Non-capacity All kWh	1,447,697	MWh	@		0.046363	$ 67,119	0.027305	$ 39,530	$ (27,589)
2	Capacity All kWh	1,447,697	MWh	@		0.035056	50,750	0.037978	54,981	4,231
	Winter (Oct. - May)									
3	Non-capacity All kWh	2,667,142	MWh	@		0.034013	90,716	0.020032	53,427	(37,289)
4	Capacity All kWh	2,667,142	MWh	@		0.025987	69,310	0.028153	75,089	5,779
5	Annual PSCR Factor	4,114,839	MWh	@		0.009410	38,721	0.009410	38,721	-
6	Total Production						$ 316,616		$ 261,748	$ (54,868)
	Transmission									
	Summer (June - Sept.)									
7	All kWh	1,447,697	MWh	@		0.026688	$ 38,636	0.027108	$ 39,245	$ 608
	Winter (Oct. - May)									
8	All kWh	2,667,142	MWh	@		0.019784	52,766	0.020095	53,597	831
9	Total Transmission						$ 91,403		$ 92,842	$ 1,439
	Delivery									
10	System Access	2,459,675	Bills	@		20.00	$ 49,193	20.00	$ 49,193	$ -
11	Distribution	4,114,839	MWh	@		0.069433	285,704	0.070823	291,424	5,720
	Provisions									
12	Education GEI	95,811	MWh	@		(0.001000)	(96)	(0.000907)	(87)	9
13	Total Delivery						$ 334,801		$ 340,530	$ 5,729
14	Total Full Service						$ 742,820		$ 695,121	$ (47,700)
	ROA SERVICE									
	Delivery									
15	System Access	1,014	Bills	@		20.00	$ 20	20.00	$ 20	$ -
16	Distribution	18,702	MWh	@		0.069433	1,299	0.070823	1,325	26
	Provisions									
17	Education GEI	11,475	MWh	@		(0.001000)	(11)	(0.000907)	(10)	1
18	Total Delivery						$ 1,307		$ 1,334	$ 27
19	Total Full & ROA Service						$ 744,128		$ 696,455	$ (47,673)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Time-of-Use (GSTU)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 10 of 32
Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	14,873	MWh	@	0.062830	$ 934	0.037004	$ 550	$ (384)
2	Mid-peak kWh	11,717	MWh	@	0.048934	573	0.028820	338	(236)
3	Off-peak kWh	4,487	MWh	@	0.036694	165	0.021611	97	(68)
	Capacity								
4	On-peak kWh	14,873	MWh	@	0.047982	714	0.051983	773	60
5	Mid-peak kWh	11,717	MWh	@	0.037369	438	0.040484	474	37
6	Off-peak kWh	4,487	MWh	@	0.028063	126	0.030403	136	10
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	25,578	MWh	@	0.037107	949	0.021854	559	(390)
8	Off-peak kWh	27,907	MWh	@	0.030029	838	0.017685	494	(344)
	Capacity								
9	On-peak kWh	25,578	MWh	@	0.028428	727	0.030799	788	61
10	Off-peak kWh	27,907	MWh	@	0.022961	641	0.024875	694	53
	Provisions								
11	Interruptible (GSI)	-	MWh	@	(0.021695)	-	(0.021695)	-	-
12	Annual PSCR Factor	84,563	MWh	@	0.009410	796	0.009410	796	-
13	Total Production					$ 6,901		$ 5,699	$ (1,202)
	Transmission								
	Summer (June - Sept.)								
14	On-peak kWh	14,873	MWh	@	0.036529	$ 543	0.037105	$ 552	$ 9
15	Mid-peak kWh	11,717	MWh	@	0.028449	333	0.028897	339	5
16	Off-peak kWh	4,487	MWh	@	0.021365	96	0.021701	97	2
	Winter (Oct. - May)								
17	On-peak kWh	25,578	MWh	@	0.021643	554	0.021984	562	9
18	Off-peak kWh	27,907	MWh	@	0.017480	488	0.017756	496	8
19	Total Transmission					$ 2,014		$ 2,046	$ 32
	Delivery								
20	System Access	22,689	Bills	@	20.00	$ 454	20.00	$ 454	$ -
21	Distribution	84,563	MWh	@	0.069433	5,871	0.070823	5,989	118
	Provisions								
22	Education GEI	-	MWh	@	(0.001000)	-	(0.000907)	-	-
23	Total Delivery					$ 6,325		$ 6,443	$ 118
24	Total Full Service					$ 15,240		$ 14,188	$ (1,052)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Demand (GSD)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 11 of 32
Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate	Present Revenue	Proposed Rate	Proposed Revenue	Net Increase / (Decrease)
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
					$/unit	$000	$/unit	$000	$000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Peak kW	2,893	MW	@	6.10	$ 17,632	4.88	$ 14,115	$ (3,517)
2	All kWh	1,048,776	MWh	@	0.032526	34,112	0.017040	17,871	(16,241)
	Capacity								
3	Peak kW	2,893	MW	@	10.17	29,425	11.36	32,868	3,443
4	All kWh	1,048,776	MWh	@	-	-	-	-	-
	Winter (Oct. - May)								
	Non-capacity								
5	Peak kW	5,338	MW	@	2.89	15,402	2.31	12,330	(3,072)
6	All kWh	1,930,830	MWh	@	0.023861	46,072	0.012501	24,138	(21,935)
	Capacity								
7	Peak kW	5,338	MW	@	9.05	48,326	10.11	53,982	5,655
8	All kWh	1,930,830	MWh	@	-	-	-	-	-
9	Power Factor Adjustment					269		219	(50)
	Provisions								
10	Interruptible (GSI)-Summer	29	MW	@	(8.50)	(247)	(8.50)	(247)	-
11	Interruptible (GSI)-Winter	53	MW	@	(7.50)	(398)	(7.50)	(398)	-
12	Annual PSCR Factor	2,979,606	MWh	@	0.009410	28,038	0.009410	28,038	-
13	Total Production					$ 218,633		$ 182,917	$ (35,716)
	Transmission								
	Summer (June - Sept.)								
14	Peak kW	2,893	MW	@	8.00	$ 23,147	8.13	$ 23,512	$ 365
	Winter (Oct. - May)								
15	Peak kW	5,338	MW	@	7.12	38,017	7.23	38,615	599
16	Total Transmission					$ 61,164		$ 62,127	$ 963
	Delivery								
17	System Access	241,823	Bills	@	30.00	$ 7,255	30.00	$ 7,255	$ -
18	Peak kW	8,231	MW	@	1.00	8,231	1.00	8,231	-
19	Distribution	2,979,606	MWh	@	0.057650	171,774	0.058482	174,253	2,479
20	Power Factor Adjustment					254		257	3
	Provisions								
21	Education GEI	131,112	MWh	@	(0.000820)	(107)	(0.000741)	(97)	10
22	Total Delivery					$ 187,406		$ 189,899	$ 2,493
23	Total Full Service					$ 467,203		$ 434,943	$ (32,260)
	ROA SERVICE								
	Delivery								
24	System Access	5,663	Bills	@	30.00	$ 170	30.00	$ 170	$ -
25	Peak kW	344	MW	@	1.00	344	1.00	344	-
26	Distribution	174,288	MWh	@	0.057650	10,048	0.058482	10,193	145
27	Power Factor Adjustment					16		16	0
	Provisions								
28	Education GEI	68,199	MWh	@	(0.000820)	(56)	(0.000741)	(51)	5
29	Total Delivery					$ 10,522		$ 10,672	$ 151
30	Total Full & ROA Service					$ 477,725		$ 445,616	$ (32,109)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 1 (GP VL 1)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	1,101	MWh	@	0.043974	$ 48	0.026948	$ 30	$ (19)
2	Capacity All kWh	1,101	MWh	@	0.027595	30	0.032799	36	6
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,353	MWh	@	0.032261	76	0.019769	47	(29)
4	Capacity All kWh	2,353	MWh	@	0.021049	50	0.025019	59	9
5	Power Factor Adjustment					3		3	(1)
6	Annual PSCR Factor	3,454	MWh	@	0.009410	33	0.009410	33	-
7	Total Production					$ 240		$ 206	$ (34)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	1,101	MWh	@	0.023364	$ 26	0.023732	$ 26	$ 0
	Winter (Oct. - May)								
9	All kWh	2,353	MWh	@	0.017822	42	0.018103	43	1
10	Total Transmission					$ 68		$ 69	$ 1
	Delivery								
11	System Access	49	Bills	@	100.00	$ 5	100.00	$ 5	$ -
12	Distribution	3,454	MWh	@	0.006957	24	0.002479	9	(15)
13	Substation Ownership Credit	700	MWh	@	(0.004093)	(3)	(0.004093)	(3)	-
14	Power Factor Adjustment					0		0	(0)
	Provisions								
15	Education GEI	-	MWh	@	(0.000578)	-	(0.000517)	-	-
16	Total Delivery					$ 26		$ 11	$ (16)
17	Total Full Service					$ 334		$ 286	$ (48)
	ROA SERVICE								
	Delivery								
18	System Access	-	Bills	@	100.00	$ -	100.00	$ -	$ -
19	Distribution	-	MWh	@	0.006957	-	0.002479	-	-
20	Substation Ownership Credit	-	MWh	@	(0.004093)	-	(0.004093)	-	-
21	Power Factor Adjustment					-		-	-
	Provisions								
22	Education GEI	-	MWh	@	(0.000578)	-	(0.000517)	-	-
23	Total Delivery					$ -		$ -	$ -
24	Total Full & ROA Service					$ 334		$ 286	$ (48)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 2 (GP VL 2)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	9,485	MWh	@	0.044489	$ 422	0.027263	$ 259	$ (163)
2	Capacity All kWh	9,485	MWh	@	0.027998	266	0.033278	316	50
	Winter (Oct. - May)								
3	Non-capacity All kWh	21,775	MWh	@	0.032638	711	0.020001	436	(275)
4	Capacity All kWh	21,775	MWh	@	0.021357	465	0.025384	553	88
5	Power Factor Adjustment					49		41	(8)
6	Annual PSCR Factor	31,259	MWh	@	0.009410	294	0.009410	294	-
7	Total Production					$ 2,206		$ 1,898	$ (309)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	9,485	MWh	@	0.023706	$ 225	0.024079	$ 228	$ 4
	Winter (Oct. - May)								
9	All kWh	21,775	MWh	@	0.018083	394	0.018367	400	6
10	Total Transmission					$ 619		$ 628	$ 10
	Delivery								
11	System Access	435	Bills	@	100.00	$ 43	100.00	$ 43	$ -
12	Distribution	31,259	MWh	@	0.010996	344	0.011188	350	6
13	Substation Ownership Credit	6,580	MWh	@	(0.004513)	(30)	(0.004513)	(30)	-
14	Power Factor Adjustment					8		8	0
	Provisions								
15	Education GEI	-	MWh	@	(0.000578)	-	(0.000517)	-	-
16	Total Delivery					$ 366		$ 372	$ 6
17	Total Full Service					$ 3,191		$ 2,898	$ (293)
	ROA SERVICE								
	Delivery								
18	System Access	24	Bills	@	100.00	$ 2	100.00	$ 2	$ -
19	Distribution	1,783	MWh	@	0.010996	20	0.011188	20	0
20	Substation Ownership Credit	-	MWh	@	(0.004513)	-	(0.004513)	-	-
21	Power Factor Adjustment					(0)		(0)	(0)
	Provisions								
22	Education GEI	-	MWh	@	(0.000578)	-	(0.000517)	-	-
23	Total Delivery					$ 22		$ 22	$ 0
24	Total Full & ROA Service					$ 3,212		$ 2,920	$ (292)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 3 (GP VL 3)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate	Present Revenue	Proposed Rate	Proposed Revenue	Net Increase / (Decrease)
					(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
					$/unit	$000	$/unit	$000	$000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	221,271	MWh	@	0.044937	$ 9,943	0.027538	$ 6,093	$ (3,850)
2	Capacity All kWh	221,271	MWh	@	0.028442	6,293	0.033806	7,480	1,187
	Winter (Oct. - May)								
3	Non-capacity All kWh	410,967	MWh	@	0.032967	13,548	0.020202	8,303	(5,246)
4	Capacity All kWh	410,967	MWh	@	0.021696	8,916	0.025787	10,598	1,681
5	Power Factor Adjustment					486		408	(78)
6	Annual PSCR Factor	632,239	MWh	@	0.009410	5,949	0.009410	5,949	-
7	Total Production					$ 45,136		$ 38,831	$ (6,306)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	221,271	MWh	@	0.024082	$ 5,329	0.024461	$ 5,413	$ 84
	Winter (Oct. - May)								
9	All kWh	410,967	MWh	@	0.018370	7,549	0.018659	7,668	119
10	Total Transmission					$ 12,878		$ 13,081	$ 203
	Delivery								
11	System Access	15,834	Bills	@	100.00	$ 1,583	100.00	$ 1,583	$ -
12	Distribution	632,239	MWh	@	0.024415	15,436	0.025001	15,806	371
13	Power Factor Adjustment					194		198	5
	Provisions								
14	Education GEI	85,102	MWh	@	(0.000578)	(49)	(0.000517)	(44)	5
15	Total Delivery					$ 17,164		$ 17,544	$ 380
16	Total Full Service					$ 75,178		$ 69,456	$ (5,723)
	ROA SERVICE								
	Delivery								
17	System Access	696	Bills	@	100.00	$ 70	100.00	$ 70	$ -
18	Distribution	70,285	MWh	@	0.024415	1,716	0.025001	1,757	41
19	Power Factor Adjustment					5		5	0
	Provisions								
20	Education GEI	36,890	MWh	@	(0.000578)	(21)	(0.000517)	(19)	2
21	Total Delivery					$ 1,770		$ 1,813	$ 44
22	Total Full & ROA Service					$ 76,948		$ 71,269	$ (5,679)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 1 (GPD VL 1)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c)	(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE									
	Production									
	Summer (June - Sept.)									
	Non-capacity									
1	On-peak kW	668	MW	@		5.96	$ 3,979	5.12	$ 3,419	$ (561)
2	On-peak kWh	86,218	MWh	@		0.040427	3,486	0.022438	1,935	(1,551)
3	Off-peak kWh	296,066	MWh	@		0.026219	7,762	0.014552	4,308	(3,454)
4	Capacity On-peak kW	668	MW	@		10.06	6,719	13.00	8,677	1,958
	Winter (Oct. - May)									
	Non-capacity									
5	On-peak kW	1,369	MW	@		5.15	7,050	4.42	6,057	(993)
6	On-peak kWh	179,258	MWh	@		0.025351	4,544	0.014070	2,522	(2,022)
7	Off-peak kWh	605,998	MWh	@		0.022012	13,339	0.012217	7,404	(5,936)
8	Capacity On-peak kW	1,369	MW	@		9.33	12,777	12.05	16,500	3,723
	Provisions									
9	Economic Development GED	-	MW	@		-	-	-	-	-
	Interruptible GI									
10	Summer Contracted kW	60	MW	@		(8.50)	(514)	(8.50)	(514)	-
11	Winter Contracted kW	121	MW	@		(7.50)	(905)	(7.50)	(905)	-
	Interruptible GI-2									
12	Summer Capacity & Transmission	-	MWh	@		0.029081	-	0.032987	-	-
13	Winter Capacity & Transmission	-	MWh	@		0.026985	-	0.030694	-	-
14	LMP	-	MWh	@		-	-	-	-	-
	Coincident Peak Provision									
15	Summer Capacity	-	MWh			-	-	0.031642	-	-
16	Summer Transmission	-	MWh			-	-	0.016191	-	-
17	Winter Capacity	-	MWh			-	-	0.028725	-	-
18	Winter Transmission	-	MWh			-	-	0.015046	-	-
19	Critical Peak Event	-	MWh			-	-	1.00	-	-
20	Power Factor Adjustment						(122)		(103)	19
21	Annual PSCR Factor	1,167,540	MWh	@		0.009410	10,987	0.009410	10,987	-
22	Total Production						$ 69,103		$ 60,286	$ (8,817)
	Transmission									
	Summer (June - Sept.)									
23	On-peak kW	668	MW	@		9.13	$ 6,094	9.27	$ 6,189	$ 96
	Winter (Oct. - May)									
24	On-peak kW	1,369	MW	@		8.50	11,632	8.63	11,815	183
25	Total Transmission						$ 17,725		$ 18,004	$ 279
	Delivery									
26	System Access	267	Bills	@		200.00	$ 53	200.00	$ 53	$ -
27	Maximum kW	2,528	MW	@		2.37	5,996	0.85	2,146	(3,849)
28	Substation Ownership	42	MW	@		(1.82)	(76)	(1.82)	(76)	-
29	Distribution	1,167,540	MWh	@		-	-	-	-	-
30	Power Factor Adjustment						(12)		(4)	8
	Provisions									
31	Education GEI	-	MWh	@		(0.000205)	-	(0.000181)	-	-
32	Total Delivery						$ 5,961		$ 2,119	$ (3,841)
33	Total Full Service						$ 92,789		$ 80,409	$ (12,380)
	ROA SERVICE									
	Delivery									
34	System Access	169	Bills	@		200.00	$ 34	200.00	$ 34	$ -
35	Maximum kW	2,403	MW	@		2.37	5,700	0.85	2,041	(3,660)
36	Substation Ownership	196	MW	@		(1.82)	(356)	(1.82)	(356)	-
37	Distribution	1,270,576	MWh	@		-	-	-	-	-
38	Power Factor Adjustment						(14)		(4)	9
	Provisions									
39	Education GEI	2,675	MWh	@		(0.000205)	(1)	(0.000181)	(0)	0
40	Total Delivery						$ 5,364		$ 1,713	$ (3,650)
41	Total Full & ROA Service						$ 98,153		$ 82,122	$ (16,030)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 2 (GPD VL 2)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	886	MW	@	6.03	$ 5,340	5.18	$ 4,588	$ (752)
2	On-peak kWh	121,063	MWh	@	0.040900	4,951	0.022700	2,748	(2,203)
3	Off-peak kWh	357,634	MWh	@	0.026526	9,486	0.014722	5,265	(4,221)
4	Capacity On-peak kW	886	MW	@	10.21	9,042	13.19	11,677	2,635
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,801	MW	@	5.21	9,381	4.48	8,060	(1,321)
6	On-peak kWh	240,894	MWh	@	0.025648	6,178	0.014235	3,429	(2,749)
7	Off-peak kWh	733,449	MWh	@	0.022270	16,334	0.012360	9,066	(7,268)
8	Capacity On-peak kW	1,801	MW	@	9.47	17,051	12.23	22,020	4,968
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	40	MW	@	(8.50)	(343)	(8.50)	(343)	-
11	Winter Contracted kW	81	MW	@	(7.50)	(608)	(7.50)	(608)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.031449	-	0.035652	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.029198	-	0.033192	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.033977	-	-
16	Summer Transmission	-	MWh		-	-	0.017399	-	-
17	Winter Capacity	-	MWh		-	-	0.030872	-	-
18	Winter Transmission	-	MWh		-	-	0.008548	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					(103)		(89)	15
21	Annual PSCR Factor	1,453,040	MWh	@	0.009410	13,673	0.009410	13,673	-
22	Total Production					$ 90,384		$ 79,486	$ (10,898)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	886	MW	@	9.26	$ 8,200	9.41	$ 8,329	$ 129
	Winter (Oct. - May)								
24	On-peak kW	1,801	MW	@	8.62	15,523	8.76	15,767	244
25	Total Transmission					$ 23,723		$ 24,096	$ 374
	Delivery								
26	System Access	721	Bills	@	200.00	$ 144	200.00	$ 144	$ -
27	Maximum kW	3,094	MW	@	3.61	11,178	3.69	11,424	246
28	Substation Ownership	269	MW	@	(1.93)	(520)	(1.93)	(520)	-
29	Distribution	1,453,040	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(14)		(15)	(0)
	Provisions								
31	Education GEI	29,734	MWh	@	(0.000205)	(6)	(0.000181)	(5)	1
32	Total Delivery					$ 10,782		$ 11,028	$ 247
33	Total Full Service					$ 124,888		$ 114,611	$ (10,278)
	ROA SERVICE								
	Delivery								
34	System Access	453	Bills	@	200.00	$ 91	200.00	$ 91	$ -
35	Maximum kW	2,306	MW	@	3.61	8,331	3.69	8,515	183
36	Substation Ownership	298	MW	@	(1.93)	(576)	(1.93)	(576)	-
37	Distribution	1,080,207	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					16		16	0
	Provisions								
39	Education GEI	66,701	MWh	@	(0.000205)	(14)	(0.000181)	(12)	2
40	Total Delivery					$ 7,848		$ 8,034	$ 185
41	Total Full & ROA Service					$ 132,737		$ 122,644	$ (10,092)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
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Primary Demand Voltage Level 3 (GPD VL 3)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	1,514	MW	@	6.09	$ 9,218	5.23	$ 7,921	$ (1,298)
2	On-peak kWh	209,315	MWh	@	0.041312	8,647	0.022929	4,799	(3,848)
3	Off-peak kWh	587,189	MWh	@	0.026793	15,733	0.014871	8,732	(7,001)
4	Capacity On-peak kW	1,514	MW	@	10.37	15,697	13.40	20,276	4,579
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	3,075	MW	@	5.26	16,175	4.52	13,902	(2,274)
6	On-peak kWh	417,471	MWh	@	0.025907	10,815	0.014379	6,003	(4,813)
7	Off-peak kWh	1,200,805	MWh	@	0.022495	27,012	0.012485	14,992	(12,020)
8	Capacity On-peak kW	3,075	MW	@	9.62	29,583	12.42	38,198	8,615
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	4	MW	@	(8.50)	(34)	(8.50)	(34)	-
11	Winter Contracted kW	8	MW	@	(7.50)	(57)	(7.50)	(57)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.033010	-	0.037405	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.031900	-	0.036099	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.035401	-	-
16	Summer Transmission	-	MWh		-	-	0.018158	-	-
17	Winter Capacity	-	MWh		-	-	0.032194	-	-
18	Winter Transmission	-	MWh		-	-	0.016902	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					91		79	(12)
21	Annual PSCR Factor	2,414,780	MWh	@	0.009410	22,723	0.009410	22,723	-
22	Total Production					$ 155,603		$ 137,532	$ (18,071)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	1,514	MW	@	9.41	$ 14,244	9.55	$ 14,463	$ 219
	Winter (Oct. - May)								
24	On-peak kW	3,075	MW	@	8.76	26,938	8.89	27,352	414
25	Total Transmission					$ 41,182		$ 41,815	$ 633
	Delivery								
26	System Access	9,273	Bills	@	200.00	$ 1,855	200.00	$ 1,855	$ -
27	Maximum kW	5,899	MW	@	6.68	39,405	6.87	40,540	1,136
28	Distribution	2,414,780	MWh	@	-	-	-	-	-
29	Power Factor Adjustment					27		28	1
	Provisions								
30	Education GEI	110,078	MWh	@	(0.000204)	(22)	(0.000181)	(20)	3
31	Total Delivery					$ 41,264		$ 42,403	$ 1,139
32	Total Full Service					$ 238,049		$ 221,750	$ (16,299)
	ROA SERVICE								
	Delivery								
33	System Access	3,656	Bills	@	200.00	$ 731	200.00	$ 731	$ -
34	Maximum kW	2,542	MW	@	6.68	16,986	6.87	17,471	485
35	Distribution	953,091	MWh	@	-	-	-	-	-
36	Power Factor Adjustment					37		38	1
	Provisions								
37	Education GEI	149,120	MWh	@	(0.000204)	(30)	(0.000181)	(27)	3
38	Total Delivery					$ 17,724		$ 18,214	$ 490
39	Total Full & ROA Service					$ 255,773		$ 239,964	$ (15,809)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Large Load Voltage Level 1

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 18 of 32
Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	3,600	MW	@	5.96	$ -	7.28	$ 26,217	$ 26,217
2	On-peak kWh	878,400	MWh	@	0.040427	-	0.022125	19,434	19,434
3	Off-peak kWh	1,756,800	MWh	@	0.026219	-	0.014349	25,208	25,208
4	Capacity On-peak kW	3,600	MW	@	10.06	-	15.40	55,450	55,450
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	7,200	MW	@	5.15	-	6.29	45,299	45,299
6	On-peak kWh	1,749,600	MWh	@	0.025351	-	0.013874	24,274	24,274
7	Off-peak kWh	3,499,200	MWh	@	0.022012	-	0.012047	42,154	42,154
8	Capacity On-peak kW	7,200	MW	@	9.33	-	14.28	102,836	102,836
	Provisions								
20	Power Factor Adjustment					-			-
21	Annual PSCR Factor	7,884,000	MWh	@	0.009410	-	0.009410	74,188	74,188
22	Total Production					$ -		$ 415,060	$ 415,060
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	3,600	MW	@	9.13	$ -	11.02	$ 39,656	$ 39,656
	Winter (Oct. - May)								
24	On-peak kW	7,200	MW	@	8.50	-	10.25	73,831	73,831
25	Total Transmission					$ -		$ 113,487	$ 113,487
	Delivery								
26	System Access	12	Bills	@	200.00	$ -	200.00	$ 2	$ 2
27	Maximum kW	10,800	MW	@	2.37	-	1.77	19,083	19,083
28	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
29	Distribution	7,884,000	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					-			-
	Provisions								
31	Education GEI	-	MWh	@	(0.000205)	-	(0.000126)	-	-
32	Total Delivery					$ -		$ 19,085	$ 19,085
33	Total Full Service					$ -		$ 547,633	$ 547,633

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 1 (GPTU VL 1)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 19 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	13,186	MWh	@	0.061877	$ 816	0.038697	$ 510	$ (306)
2	Mid-peak kWh	17,748	MWh	@	0.055068	977	0.034439	611	(366)
3	Low-peak kWh	48,608	MWh	@	0.044513	2,164	0.027838	1,353	(811)
4	Off-peak kWh	86,924	MWh	@	0.033174	2,884	0.020747	1,803	(1,080)
	Capacity								
5	High-peak kWh	13,186	MWh	@	0.035267	465	0.043767	577	112
6	Mid-peak kWh	17,748	MWh	@	0.031400	557	0.038968	692	134
7	Low-peak kWh	48,608	MWh	@	0.025306	1,230	0.031405	1,527	296
8	Off-peak kWh	86,924	MWh	@	0.018927	1,645	0.023489	2,042	397
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	26,006	MWh	@	0.039842	1,036	0.024917	648	(388)
10	Mid-peak kWh	36,415	MWh	@	0.036938	1,345	0.023101	841	(504)
11	Off-peak kWh	235,629	MWh	@	0.031011	7,307	0.019394	4,570	(2,737)
	Capacity								
12	High-peak kWh	26,006	MWh	@	0.022720	591	0.028195	733	142
13	Mid-peak kWh	36,415	MWh	@	0.021035	766	0.026104	951	185
14	Off-peak kWh	235,629	MWh	@	0.017499	4,123	0.021716	5,117	994
15	Power Factor Adjustment					42		36	(6)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	464,518	MWh	@	0.009410	4,371	0.009410	4,371	-
19	Total Production					$ 30,320		$ 26,382	$ (3,938)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	13,186	MWh	@	0.030861	$ 407	0.031347	$ 413	$ 6
21	Mid-peak kWh	17,748	MWh	@	0.027477	488	0.027910	495	8
22	Low-peak kWh	48,608	MWh	@	0.022144	1,076	0.022493	1,093	17
23	Off-peak kWh	86,924	MWh	@	0.016563	1,440	0.016824	1,462	23
24	Winter (Oct. - May)								
25	High-peak kWh	26,006	MWh	@	0.019881	517	0.020194	525	8
26	Mid-peak kWh	36,415	MWh	@	0.018407	670	0.018697	681	11
27	Off-peak kWh	235,629	MWh	@	0.015313	3,608	0.015554	3,665	57
28	Total Transmission					$ 8,206		$ 8,335	$ 129
	Delivery								
29	System Access	280	Bills	@	200.00	$ 56	200.00	$ 56	$ -
30	Maximum kW	1,315	MW	@	2.37	3,119	0.85	1,117	(2,002)
31	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
32	Distribution	464,518	MWh	@	-	-	-	-	-
33	Power Factor Adjustment					5		2	(3)
	Provisions								
34	Education GEI	39,403	MWh	@	(0.000205)	(8)	(0.000181)	(7)	1
35	Total Delivery					$ 3,172		$ 1,167	$ (2,005)
36	Total Full Service					$ 41,698		$ 35,884	$ (5,814)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 2 (GPTU VL 2)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 20 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	16,699	MWh	@	0.062601	$ 1,045	0.039150	$ 654	$ (392)
2	Mid-peak kWh	22,367	MWh	@	0.055712	1,246	0.034842	779	(467)
3	Low-peak kWh	51,905	MWh	@	0.045034	2,337	0.028164	1,462	(876)
4	Off-peak kWh	84,694	MWh	@	0.033562	2,843	0.020989	1,778	(1,065)
	Capacity								
5	High-peak kWh	16,699	MWh	@	0.035782	598	0.044406	742	144
6	Mid-peak kWh	22,367	MWh	@	0.031859	713	0.039537	884	172
7	Low-peak kWh	51,905	MWh	@	0.025675	1,333	0.031863	1,654	321
8	Off-peak kWh	84,694	MWh	@	0.019204	1,626	0.023832	2,018	392
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	32,702	MWh	@	0.040309	1,318	0.025209	824	(494)
10	Mid-peak kWh	44,338	MWh	@	0.037370	1,657	0.023371	1,036	(621)
11	Off-peak kWh	243,938	MWh	@	0.031374	7,653	0.019621	4,786	(2,867)
	Capacity								
12	High-peak kWh	32,702	MWh	@	0.023051	754	0.028607	936	182
13	Mid-peak kWh	44,338	MWh	@	0.021342	946	0.026485	1,174	228
14	Off-peak kWh	243,938	MWh	@	0.017754	4,331	0.022033	5,375	1,044
15	Power Factor Adjustment					(12)		(10)	2
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	496,642	MWh	@	0.009410	4,673	0.009410	4,673	-
19	Total Production					$ 33,061		$ 28,765	$ (4,296)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	16,699	MWh	@	0.031312	$ 523	0.031805	$ 531	$ 8
21	Mid-peak kWh	22,367	MWh	@	0.027879	624	0.028318	633	10
22	Low-peak kWh	51,905	MWh	@	0.022468	1,166	0.022821	1,185	18
23	Off-peak kWh	84,694	MWh	@	0.016805	1,423	0.017069	1,446	22
	Winter (Oct. - May)								
24	High-peak kWh	32,702	MWh	@	0.020172	660	0.020489	670	10
25	Mid-peak kWh	44,338	MWh	@	0.018676	828	0.018970	841	13
26	Off-peak kWh	243,938	MWh	@	0.015536	3,790	0.015781	3,850	60
27	Total Transmission					$ 9,013		$ 9,155	$ 142
	Delivery								
28	System Access	963	Bills	@	200.00	$ 193	200.00	$ 193	$ -
29	Maximum kW	1,431	MW	@	3.61	5,168	3.69	5,282	114
30	Substation Ownership	235	MW	@	(1.93)	(453)	(1.93)	(453)	-
31	Distribution	496,642	MWh	@	-	-	-	-	-
32	Power Factor Adjustment					(2)		(2)	(0)
	Provisions								
33	Education GEI	18,544	MWh	@	(0.000205)	(4)	(0.000181)	(3)	0
34	Total Delivery					$ 4,902		$ 5,016	$ 114
35	Total Full Service					$ 46,976		$ 42,937	$ (4,040)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 3 (GPTU VL 3)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	127,203	MWh	@	0.063232	$ 8,043	0.039545	$ 5,030	$ (3,013)
2	Mid-peak kWh	168,181	MWh	@	0.056274	9,464	0.035193	5,919	(3,545)
3	Low-peak kWh	375,163	MWh	@	0.045488	17,065	0.028448	10,673	(6,393)
4	Off-peak kWh	562,171	MWh	@	0.033901	19,058	0.021201	11,919	(7,139)
	Capacity								
5	High-peak kWh	127,203	MWh	@	0.036350	4,624	0.045111	5,738	1,114
6	Mid-peak kWh	168,181	MWh	@	0.032364	5,443	0.040164	6,755	1,312
7	Low-peak kWh	375,163	MWh	@	0.026083	9,785	0.032369	12,144	2,358
8	Off-peak kWh	562,171	MWh	@	0.019509	10,967	0.024210	13,610	2,643
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	216,061	MWh	@	0.040715	8,797	0.025463	5,501	(3,295)
10	Mid-peak kWh	295,549	MWh	@	0.037747	11,156	0.023607	6,977	(4,179)
11	Off-peak kWh	1,567,912	MWh	@	0.031690	49,687	0.019819	31,074	(18,613)
	Capacity								
12	High-peak kWh	216,061	MWh	@	0.023417	5,060	0.029061	6,279	1,219
13	Mid-peak kWh	295,549	MWh	@	0.021680	6,408	0.026906	7,952	1,544
14	Off-peak kWh	1,567,912	MWh	@	0.018036	28,279	0.022383	35,095	6,816
15	Power Factor Adjustment					456		387	(69)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	3,312,240	MWh	@	0.009410	31,168	0.009410	31,168	-
19	Total Production					$ 225,460		$ 196,220	$ (29,240)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	127,203	MWh	@	0.031809	$ 4,046	0.032310	$ 4,110	$ 64
21	Mid-peak kWh	168,181	MWh	@	0.028321	4,763	0.028767	4,838	75
22	Low-peak kWh	375,163	MWh	@	0.022824	8,563	0.023184	8,698	135
23	Off-peak kWh	562,171	MWh	@	0.017071	9,597	0.017340	9,748	151
	Winter (Oct. - May)								
24	High-peak kWh	216,061	MWh	@	0.020492	4,427	0.020814	4,497	70
25	Mid-peak kWh	295,549	MWh	@	0.018972	5,607	0.019271	5,695	88
26	Off-peak kWh	1,567,912	MWh	@	0.015783	24,746	0.016031	25,136	390
27	Total Transmission					$ 61,750		$ 62,722	$ 972
	Delivery								
28	System Access	16,957	Bills	@	200.00	$ 3,391	200.00	$ 3,391	$ -
29	Maximum kW	10,275	MW	@	6.68	68,656	6.87	70,618	1,962
30	Distribution	3,312,240	MWh	@	-	-	-	-	-
31	Power Factor Adjustment					161		166	5
	Provisions								
32	Education GEI	278,712	MWh	@	(0.000204)	(57)	(0.000181)	(50)	6
33	Total Delivery					$ 72,152		$ 74,125	$ 1,973
34	Total Full Service					$ 359,362		$ 333,068	$ (26,295)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 1 (EIP VL 1)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 22 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	206	MWh	@	0.099498	$ 21	0.065261	$ 13	$ (7)
2	High-peak kWh	7,015	MWh	@	0.066332	465	0.043507	305	(160)
3	Mid-peak kWh	7,214	MWh	@	0.059487	429	0.039018	281	(148)
4	Low-peak kWh	45,458	MWh	@	0.047278	2,149	0.031010	1,410	(740)
5	Off-peak kWh	61,205	MWh	@	0.034619	2,119	0.022707	1,390	(729)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	206	MWh	@	0.040218	8	0.058958	12	4
8	High-peak kWh	7,015	MWh	@	0.026812	188	0.039306	276	88
9	Mid-peak kWh	7,214	MWh	@	0.023872	172	0.034996	252	80
10	Low-peak kWh	45,458	MWh	@	0.019239	875	0.028203	1,282	408
11	Off-peak kWh	61,205	MWh	@	0.014390	881	0.021095	1,291	410
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	647	MWh	@	0.062127	40	0.040749	26	(14)
13	High-peak kWh	14,105	MWh	@	0.041418	584	0.027166	383	(201)
14	Mid-peak kWh	14,704	MWh	@	0.038779	570	0.025435	374	(196)
15	Off-peak kWh	182,038	MWh	@	0.032609	5,936	0.021388	3,893	(2,043)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	647	MWh	@	0.025909	17	0.037982	25	8
18	High-peak kWh	14,105	MWh	@	0.017272	244	0.025321	357	114
19	Mid-peak kWh	14,704	MWh	@	0.015992	235	0.023443	345	110
20	Off-peak kWh	182,038	MWh	@	0.013303	2,422	0.019503	3,550	1,128
21	Power Factor Adjustment					7		6	(1)
22	Interruptible Credit	332,592	MWh	@	(0.008461)	(2,814)	(0.008461)	(2,814)	-
23	Annual PSCR Factor	332,592	MWh	@	0.009410	3,130	0.009410	3,130	-
24	Total Production					$ 17,677		$ 15,788	$ (1,889)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	206	MWh	@	0.041546	$ 9	0.042201	$ 9	$ 0
26	High-peak kWh	7,015	MWh	@	0.027698	194	0.028134	197	3
27	Mid-peak kWh	7,214	MWh	@	0.024660	178	0.025049	181	3
28	Low-peak kWh	45,458	MWh	@	0.019874	903	0.020187	918	14
29	Off-peak kWh	61,205	MWh	@	0.014865	910	0.015099	924	14
	Winter (Oct. - May)								
30	Critical-peak kWh	647	MWh	@	0.026765	17	0.027186	18	0
31	High-peak kWh	14,105	MWh	@	0.017843	252	0.018124	256	4
32	Mid-peak kWh	14,704	MWh	@	0.016520	243	0.016780	247	4
33	Off-peak kWh	182,038	MWh	@	0.013743	2,502	0.013959	2,541	39
34	Total Transmission					$ 5,208		$ 5,290	$ 82
	Delivery								
35	System Access	64	Bills	@	200.00	$ 13	200.00	$ 13	$ -
36	Maximum kW	771	MW	@	2.37	1,830	0.85	655	(1,175)
37	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
38	Power Factor Adjustment					1		0	(0)
39	Distribution	332,592	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,843		$ 668	$ (1,175)
41	Total Full Service					$ 24,728		$ 21,746	$ (2,982)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 2 (EIP VL 2)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 23 of 32
Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	27	MWh	@	0.100662	$ 3	0.066024	$ 2	$ (1)
2	High-peak kWh	895	MWh	@	0.067108	60	0.044016	39	(21)
3	Mid-peak kWh	937	MWh	@	0.060183	56	0.039474	37	(19)
4	Low-peak kWh	7,371	MWh	@	0.047832	353	0.031373	231	(121)
5	Off-peak kWh	10,461	MWh	@	0.035024	366	0.022973	240	(126)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	27	MWh	@	0.040805	1	0.059819	2	1
8	High-peak kWh	895	MWh	@	0.027203	24	0.039879	36	11
9	Mid-peak kWh	937	MWh	@	0.024220	23	0.035507	33	11
10	Low-peak kWh	7,371	MWh	@	0.019519	144	0.028615	211	67
11	Off-peak kWh	10,461	MWh	@	0.014600	153	0.021403	224	71
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	79	MWh	@	0.062854	5	0.041226	3	(2)
13	High-peak kWh	1,503	MWh	@	0.041903	63	0.027484	41	(22)
14	Mid-peak kWh	1,737	MWh	@	0.039232	68	0.025733	45	(23)
15	Off-peak kWh	30,227	MWh	@	0.032990	997	0.021638	654	(343)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	79	MWh	@	0.026287	2	0.038536	3	1
18	High-peak kWh	1,503	MWh	@	0.017525	26	0.025691	39	12
19	Mid-peak kWh	1,737	MWh	@	0.016225	28	0.023786	41	13
20	Off-peak kWh	30,227	MWh	@	0.013498	408	0.019787	598	190
21	Power Factor Adjustment					(14)		(12)	1
22	Interruptible Credit	53,237	MWh	@	(0.008461)	(450)	(0.008461)	(450)	-
23	Annual PSCR Factor	53,237	MWh	@	0.009410	501	0.009410	501	-
24	Total Production					$ 2,817		$ 2,518	$ (300)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	27	MWh	@	0.042153	$ 1	0.042817	$ 1	$ 0
26	High-peak kWh	895	MWh	@	0.028102	25	0.028544	26	0
27	Mid-peak kWh	937	MWh	@	0.025021	23	0.025415	24	0
28	Low-peak kWh	7,371	MWh	@	0.020164	149	0.020482	151	2
29	Off-peak kWh	10,461	MWh	@	0.015082	158	0.015320	160	2
	Winter (Oct. - May)								
30	Critical-peak kWh	79	MWh	@	0.027155	2	0.027583	2	0
31	High-peak kWh	1,503	MWh	@	0.018104	27	0.018389	28	0
32	Mid-peak kWh	1,737	MWh	@	0.016761	29	0.017025	30	0
33	Off-peak kWh	30,227	MWh	@	0.013944	421	0.014163	428	7
34	Total Transmission					$ 836		$ 849	$ 13
	Delivery								
35	System Access	82	Bills	@	200.00	$ 16	200.00	$ 16	$ -
36	Maximum kW	373	MW	@	3.61	1,347	3.69	1,376	30
37	Substation Ownership	169	MW	@	(1.93)	(326)	(1.93)	(326)	-
38	Power Factor Adjustment					(5)		(5)	(0)
39	Distribution	53,237	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,032		$ 1,061	$ 30
41	Total Full Service					$ 4,685		$ 4,428	$ (257)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 3 (EIP VL 3)

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	1	MWh	@	0.101677	$ 0	0.066690	$ 0	$ (0)
2	High-peak kWh	66	MWh	@	0.067784	5	0.044460	3	(2)
3	Mid-peak kWh	104	MWh	@	0.060790	6	0.039872	4	(2)
4	Low-peak kWh	1,569	MWh	@	0.048314	76	0.031689	50	(26)
5	Off-peak kWh	908	MWh	@	0.035378	32	0.023204	21	(11)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	1	MWh	@	0.041452	0	0.060768	0	0
8	High-peak kWh	66	MWh	@	0.027635	2	0.040512	3	1
9	Mid-peak kWh	104	MWh	@	0.024605	3	0.036070	4	1
10	Low-peak kWh	1,569	MWh	@	0.019829	31	0.029069	46	14
11	Off-peak kWh	908	MWh	@	0.014831	13	0.021742	20	6
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	4	MWh	@	0.063488	0	0.041642	0	(0)
13	High-peak kWh	93	MWh	@	0.042325	4	0.027761	3	(1)
14	Mid-peak kWh	119	MWh	@	0.039628	5	0.025992	3	(2)
15	Off-peak kWh	3,871	MWh	@	0.033323	129	0.021856	85	(44)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	4	MWh	@	0.026704	0	0.039148	0	0
18	High-peak kWh	93	MWh	@	0.017803	2	0.026099	2	1
19	Mid-peak kWh	119	MWh	@	0.016483	2	0.024163	3	1
20	Off-peak kWh	3,871	MWh	@	0.013712	53	0.020101	78	25
21	Power Factor Adjustment					(1)		(1)	0
22	Interruptible Credit	6,737	MWh	@	(0.008461)	(57)	(0.008461)	(57)	-
23	Annual PSCR Factor	6,737	MWh	@	0.009410	63	0.009410	63	-
24	Total Production					$ 368		$ 329	$ (39)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	1	MWh	@	0.042822	$ 0	0.043496	$ 0	$ 0
26	High-peak kWh	66	MWh	@	0.028548	2	0.028997	2	0
27	Mid-peak kWh	104	MWh	@	0.025418	3	0.025818	3	0
28	Low-peak kWh	1,569	MWh	@	0.020484	32	0.020807	33	1
29	Off-peak kWh	908	MWh	@	0.015321	14	0.015563	14	0
	Winter (Oct. - May)								
30	Critical-peak kWh	4	MWh	@	0.027586	0	0.028021	0	0
31	High-peak kWh	93	MWh	@	0.018391	2	0.018681	2	0
32	Mid-peak kWh	119	MWh	@	0.017027	2	0.017295	2	0
33	Off-peak kWh	3,871	MWh	@	0.014165	55	0.014388	56	1
34	Total Transmission					$ 109		$ 111	$ 2
	Delivery								
35	System Access	54	Bills	@	200.00	$ 11	200.00	$ 11	$ -
36	Maximum kW	40	MW	@	6.68	267	6.87	274	8
37	Power Factor Adjustment					(1)		(1)	(0)
38	Distribution	6,737	MWh	@	-	-	-	-	-
39	Total Delivery					$ 277		$ 284	$ 8
40	Total Full Service					$ 754		$ 725	$ (30)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Metered Lighting (GML)

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Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
1	Secondary All kWh	10,328	MWh	@	0.034716	$ 359	0.039404	$ 407	$ 48
2	Primary All kWh	448	MWh	@	0.017037	8	0.019338	9	1
3	Annual PSCR Factor	10,776	MWh	@	0.009410	101	0.009410	101	-
4	Total Production					$ 468		$ 517	$ 49
	Transmission								
5	Secondary All kWh	10,328	MWh	@	0.010556	109	0.010722	111	2
6	Primary All kWh	448	MWh	@	0.005180	2	0.005262	2	0
7	Total Transmission	10,776				111		113	2
	Delivery								
	Secondary								
8	System Access	4,489	Bills	@	10.00	$ 45	10.00	$ 45	$ -
9	Distribution	10,328	MWh	@	0.118564	1,225	0.119748	1,237	12
	Primary								
10	System Access	297	Bills	@	20.00	$ 6	20.00	$ 6	$ -
11	Distribution	448	MWh	@	0.090355	41	0.091258	41	0
12	Total Delivery					$ 1,316		$ 1,328	$ 13
13	Total Full Service					$ 1,895		$ 1,959	$ 64

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Universal Unmetered Light (UUL)

Case No.: U-22070
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Witness: LMConnolly
Date: June 2026

Line		Billing Determinants							Present					Proposed					Net Increase
						Customer	Company		Customer Owned		Company Owned			Customer Owned		Company Owned			
No.	Description	Customer	Company	Units	Watts	MWh	MWh		Production	Delivery	Production	Delivery	Revenue	Production	Delivery	Production	Delivery	Revenue	/ (Decrease)
									$/Light	$/Light	$/Light	$/Light	$000	$/Light	$/Light	$/Light	$/Light	$000	$000
1	15 - 24 Watts	12	-	Lights	20	0	-	@	0.28	7.29	0.28	10.29	$ 0	0.30	7.45	0.30	10.45	$ 0	$ 0
2	25 - 34 Watts	-	64,500	Lights	30	-	666	@	0.43	8.07	0.43	11.07	742	0.45	8.25	0.45	11.25	755	13
3	35 - 44 Watts	1,524	412,356	Lights	40	21	5,701	@	0.57	8.85	0.57	11.85	5,136	0.60	9.05	0.60	12.05	5,231	95
4	45 - 54 Watts	1,308	865,773	Lights	50	23	15,000	@	0.72	9.63	0.72	12.63	11,572	0.75	9.84	0.75	12.84	11,780	208
5	55 - 64 Watts	1,092	7,056	Lights	60	23	147	@	0.86	10.41	0.86	13.41	113	0.91	10.64	0.91	13.64	115	2
6	65 - 74 Watts	312	129,516	Lights	70	8	3,150	@	1.01	11.19	1.01	14.19	1,972	1.06	11.44	1.06	14.44	2,011	39
7	75 - 84 Watts	72	34,020	Lights	80	2	947	@	1.15	11.97	1.15	14.97	549	1.21	12.23	1.21	15.23	560	11
8	85 - 94 Watts	-	98,178	Lights	90	-	3,075	@	1.29	12.75	1.29	15.75	1,673	1.36	13.03	1.36	16.03	1,707	34
9	95 - 104 Watts	-	180	Lights	100	-	6	@	1.44	13.53	1.44	16.53	3	1.52	13.83	1.52	16.83	3	0
10	105 - 114 Watts	-	7,044	Lights	110	-	270	@	1.58	14.31	1.58	17.31	133	1.67	14.62	1.67	17.62	136	3
11	115 - 124 Watts	804	364,751	Lights	120	34	15,256	@	1.73	15.09	1.73	18.09	7,243	1.82	15.42	1.82	18.42	7,396	154
12	125 - 134 Watts	-	320	Lights	130	-	15	@	1.87	15.86	1.87	18.86	7	1.97	16.22	1.97	19.22	7	0
13	135 - 144 Watts	-	924	Lights	140	-	45	@	2.02	16.64	2.02	19.64	20	2.13	17.01	2.13	20.01	20	0
14	145 - 154 Watts	-	3,996	Lights	150	-	209	@	2.16	17.42	2.16	20.42	90	2.28	17.81	2.28	20.81	92	2
15	155 - 164 Watts	-	52	Lights	160	-	3	@	2.31	18.20	2.31	21.20	1	2.43	18.61	2.43	21.61	1	0
16	165 - 174 Watts	1,404	51,182	Lights	170	83	3,036	@	2.45	18.98	2.45	21.98	1,280	2.58	19.40	2.58	22.40	1,309	29
17	175 - 184 Watts	-	-	Lights	180	-	-	@	2.60	19.76	2.60	22.76	-	2.73	20.20	2.73	23.20	-	-
18	185 - 194 Watts	-	156	Lights	190	-	10	@	2.74	20.54	2.74	23.54	4	2.89	21.00	2.89	24.00	4	0
19	195 - 204 Watts	-	60	Lights	200	-	4	@	2.89	21.32	2.89	24.32	2	3.04	21.79	3.04	24.79	2	0
20	205 - 214 Watts	504	12,740	Lights	210	37	934	@	3.03	22.10	3.03	25.10	371	3.19	22.59	3.19	25.59	380	9
21	215 - 224 Watts	-	28	Lights	220	-	2	@	3.17	22.88	3.17	25.88	1	3.34	23.39	3.34	26.39	1	0
22	225 - 234 Watts	-	-	Lights	230	-	-	@	3.32	23.66	3.32	26.66	-	3.50	24.18	3.50	27.18	-	-
23	235 - 244 Watts	-	-	Lights	240	-	-	@	3.46	24.44	3.46	27.44	-	3.65	24.98	3.65	27.98	-	-
24	245 - 254 Watts	60	432	Lights	250	5	38	@	3.61	25.22	3.61	28.22	15	3.80	25.78	3.80	28.78	16	0
25	255 - 264 Watts	-	-	Lights	260	-	-	@	3.75	26.00	3.75	29.00	-	3.95	26.57	3.95	29.57	-	-
26	265 - 274 Watts	-	-	Lights	270	-	-	@	3.90	26.78	3.90	29.78	-	4.11	27.37	4.11	30.37	-	-
27	275 - 284 Watts	396	3,949	Lights	280	39	386	@	4.04	27.56	4.04	30.56	149	4.26	28.17	4.26	31.17	153	4
28	285 - 294 Watts	12	1,292	Lights	290	1	131	@	4.19	28.34	4.19	31.34	46	4.41	28.96	4.41	31.96	47	1
29	295 - 304 Watts	-	-	Lights	300	-	-	@	4.33	29.12	4.33	32.12	-	4.56	29.76	4.56	32.76	-	-
30	305 - 314 Watts	108	-	Lights	310	12	-	@	4.48	29.90	4.48	32.90	4	4.72	30.56	4.72	33.56	4	0
31	315 - 324 Watts	540	29,081	Lights	320	60	3,252	@	4.62	30.68	4.62	33.68	1,133	4.87	31.35	4.87	34.35	1,160	27
32	325 - 334 Watts	-	-	Lights	330	-	-	@	4.77	31.45	4.77	34.45	-	5.02	32.15	5.02	35.15	-	-
33	335 - 344 Watts	-	-	Lights	340	-	-	@	4.91	32.23	4.91	35.23	-	5.17	32.95	5.17	35.95	-	-
34	345 - 354 Watts	-	-	Lights	350	-	-	@	5.05	33.01	5.05	36.01	-	5.33	33.74	5.33	36.74	-	-
35	355 - 364 Watts	-	-	Lights	360	-	-	@	5.20	33.79	5.20	36.79	-	5.48	34.54	5.48	37.54	-	-
36	365 - 374 Watts	-	-	Lights	370	-	-	@	5.34	34.57	5.34	37.57	-	5.63	35.33	5.63	38.33	-	-
37	375 - 384 Watts	-	-	Lights	380	-	-	@	5.49	35.35	5.49	38.35	-	5.78	36.13	5.78	39.13	-	-
38	385 - 394 Watts	-	-	Lights	390	-	-	@	5.63	36.13	5.63	39.13	-	5.93	36.93	5.93	39.93	-	-
39	395 - 404 Watts	-	12	Lights	400	-	2	@	5.78	36.91	5.78	39.91	1	6.09	37.72	6.09	40.72	1	0
40	405 - 414 Watts	24	24	Lights	410	3	3	@	5.92	37.69	5.92	40.69	2	6.24	38.52	6.24	41.52	2	0
41	415 - 424 Watts	-	-	Lights	420	-	-	@	6.07	38.47	6.07	41.47	-	6.39	39.32	6.39	42.32	-	-
42	425 - 434 Watts	-	-	Lights	430	-	-	@	6.21	39.25	6.21	42.25	-	6.54	40.11	6.54	43.11	-	-
43	435 - 444 Watts	-	-	Lights	440	-	-	@	6.36	40.03	6.36	43.03	-	6.70	40.91	6.70	43.91	-	-
44	445 - 454 Watts	-	-	Lights	450	-	-	@	6.50	40.81	6.50	43.81	-	6.85	41.71	6.85	44.71	-	-
45	455 - 464 Watts	888	1,460	Lights	460	143	235	@	6.65	41.59	6.65	44.59	118	7.00	42.50	7.00	45.50	121	3
46	465 - 474 Watts	-	-	Lights	470	-	-	@	6.79	42.37	6.79	45.37	-	7.15	43.30	7.15	46.30	-	-
47	475 - 484 Watts	180	9,489	Lights	480	30	1,593	@	6.94	43.15	6.94	46.15	513	7.31	44.10	7.31	47.10	526	13
48	Conversion Credit	-	129,840	Lights								(7.72)	(1,002)				(7.72)	(1,002)	-
49	Annual PSCR Factor	9,240	2,098,571	Lights		524	54,116		0.009410		0.009410		514	0.009410		0.009410		514	-
50	Total Unmetered LED	9,240	2,098,571	Lights		524	54,116						$ 32,405					$ 33,052	$ 648

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Unmetered Service (GU)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
1	Non-capacity All kWh	99,352	MWh	@	0.037706	$ 3,746	0.024821	$ 2,466	$ (1,280)
2	Capacity All kWh	99,352	MWh	@	0.015927	1,582	0.021372	2,123	541
3	Annual PSCR Factor	99,352	MWh	@	0.009410	935	0.009410	935	-
4	Total Production					$ 6,264		$ 5,524	$ (739)
	Transmission								
5	All kWh	99,352	MWh	@	0.015085	1,499	0.015322	1,522	24
	Delivery								
6	System Access	5,578	Bills	@	2.00	$ 11	2.00	$ 11	$ -
7	Distribution	99,352	MWh	@	0.034452	3,423	0.034831	3,461	38
8	Total Delivery					$ 3,434		$ 3,472	$ 38
9	Total Full Service					$ 11,196		$ 10,518	$ (678)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Large Self-generation (GSG-2)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	STANDBY SERVICE								
	Production								
	Voltage Level 1								
1	On-peak kW-day	108	MW	@	11.57	$ 1,254	11.57	$ 1,254	$ -
2	All kWh	77,349	MWh	@	0.046132	3,568	0.046132	3,568	-
	Voltage Level 2								
3	On-peak kW-day	223	MW	@	11.73	2,613	11.73	2,613	-
4	All kWh	77,337	MWh	@	0.048126	3,722	0.048126	3,722	-
	Voltage Level 3								
5	On-peak kW-day	55	MW	@	11.91	650	11.91	650	-
6	All kWh	18,615	MWh	@	0.047120	877	0.047120	877	-
7	Power Factor Adjustment					261		261	-
8	Total Production					$ 12,946		$ 12,946	$ -
	Transmission								
	Voltage Level 1								
9	On-peak kW-day	108	MW	@	3.05	$ 330	3.05	$ 330	$ -
	Voltage Level 2								
10	On-peak kW-day	223	MW	@	3.09	688	3.09	688	-
	Voltage Level 3								
11	On-peak kW-day	55	MW	@	3.14	171	3.14	171	-
12	Total Transmission					$ 1,190		$ 1,190	$ -
	Delivery								
	System Access								
	Voltage Level 1								
13	Standby	64	Bills	@	100.00	$ 6	100.00	$ 6	$ -
14	Supplemental	-	Bills	@	100.00	-	100.00	-	-
15	Maximum kW	889	MW	@	2.37	2,110	0.85	755	(1,355)
16	Interconnect	355	MW	@	(2.37)	(842)	(0.85)	(301)	541
17	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
	Voltage Level 2								
18	Standby	94	Bills	@	100.00	$ 9	100.00	$ 9	$ -
19	Supplemental	-	Bills	@	100.00	-	100.00	-	-
20	Maximum kW	610	MW	@	3.61	2,203	3.69	2,252	49
21	Substation Ownership	288	MW	@	(1.93)	(555)	(1.93)	(555)	-
	Voltage Level 3								
22	Standby	13	Bills	@	100.00	$ 1	100.00	$ 1	$ -
23	Supplemental	-	Bills	@	100.00	-	100.00	-	-
24	Maximum kW	62	MW	@	6.68	412	6.87	424	12
25	Power Factor Adjustment					63		54	(9)
26	Total Delivery					$ 3,408		$ 2,645	$ (763)
27	Total Standby Service					$ 17,543		$ 16,781	$ (763)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response (DR) Surcharge

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Line No.	(a) Description	(b) Program plus Cust. Credits (1)	(c) Financial Incentive (1)	(d) Reconciled Balance (1)	(e) Total	(f) Units
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	0.001567	-	-	0.001567	per kWh
2	Smart Hours RSH	0.001567	-	-	0.001567	per kWh
3	Night Time Savers RPM	0.001567	-	-	0.001567	per kWh
4	Non-Transmitting Meters RSM	0.001567	-	-	0.001567	per kWh
	Secondary Class					
5	Energy-only GS	0.001506	-	-	0.001506	per kWh
6	Time-of-Use GSTU	0.001506	-	-	0.001506	per kWh
7	Demand GSD	0.51	-	-	0.51	per Peak kW
	Primary Class					
	Energy-only GP					
8	Voltage Level 1	0.001365	-	-	0.001365	per kWh
9	Voltage Level 2	0.001381	-	-	0.001381	per kWh
10	Voltage Level 3	0.001395	-	-	0.001395	per kWh
	Demand GPD					
11	Voltage Level 1	0.62	-	-	0.62	per On-Peak kW
12	Voltage Level 2	0.63	-	-	0.63	per On-Peak kW
13	Voltage Level 3	0.64	-	-	0.64	per On-Peak kW
14	Large Load	0.78	-	-	0.78	per On-Peak kW
	Time-of-Use GPTU					
15	Voltage Level 1	0.001273	-	-	0.001273	per kWh
16	Voltage Level 2	0.001288	-	-	0.001288	per kWh
17	Voltage Level 3	0.001301	-	-	0.001301	per kWh
	Energy Intensive EIP					
18	Voltage Level 1	0.001143	-	-	0.001143	per kWh
19	Voltage Level 2	0.001156	-	-	0.001156	per kWh
20	Voltage Level 3	0.001168	-	-	0.001168	per kWh
	Lighting & Unmetered Class					
21	Metered Lighting GML	0.000885	-	-	0.000885	per kWh
22	Universal Unmetered Lighting UUL	0.000756	-	-	0.000756	per kWh
23	Unmetered GU	0.001133	-	-	0.001133	per kWh
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	NA	NA	NA	NA	
25	Demand GSD	NA	NA	NA	NA	
	Primary Class					
	Energy-only GP					
26	Voltage Level 1	NA	NA	NA	NA	
27	Voltage Level 2	NA	NA	NA	NA	
28	Voltage Level 3	NA	NA	NA	NA	
	Demand GPD					
29	Voltage Level 1	NA	NA	NA	NA	
30	Voltage Level 2	NA	NA	NA	NA	
31	Voltage Level 3	NA	NA	NA	NA	

(1) WP-LMC-19

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Rate Case (ERC) Deferral Surcharge

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 30 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) ERC Deferral [1] ($000)	(d) ERC Deferral Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 15,413	0.001215
	Secondary Class			
2	Energy-only GS	4,114,839	3,839	0.000933
3	Time-of-Use GSTU	84,563	79	0.000933
4	Demand GSD	2,979,606	2,139	0.000718
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	0	0.000043
6	Voltage Level 2	31,259	6	0.000179
7	Voltage Level 3	632,239	195	0.000308
	Demand GPD			
8	Voltage Level 1	1,167,540	30	0.000026
9	Voltage Level 2	1,453,040	157	0.000108
10	Voltage Level 3	2,414,780	449	0.000186
11	Large Load	7,884,000	205	0.000026
	Time-of-Use GPTU			
12	Voltage Level 1	464,518	12	0.000026
13	Voltage Level 2	496,642	54	0.000108
14	Voltage Level 3	3,312,240	616	0.000186
	Energy Intensive EIP			
15	Voltage Level 1	332,592	9	0.000026
16	Voltage Level 2	53,237	6	0.000108
17	Voltage Level 3	6,737	1	0.000186
	Lighting & Unmetered Class			
18	Metered Lighting GML	10,776	15	0.001397
19	Universal Unmetered Lighting UUL	54,640	342	0.006258
20	Unmetered GU	99,352	40	0.000399
	Self-generation Class			
21	Large Self-generation GSG-2			
22	Voltage Level 1	77,349	2	0.000026
23	Voltage Level 2	77,337	8	0.000108
24	Voltage Level 3	18,615	3	0.000186
25	Total Full Service		$ 23,620	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) ERC Deferral [1] ($000)	(h) ERC Deferral Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001215
	Secondary Class			
2	Energy-only GS	18,702	17	0.000933
3	Time-of-Use GSTU	-	-	0.000933
4	Demand GSD	174,288	125	0.000718
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000043
6	Voltage Level 2	1,783	0	0.000179
7	Voltage Level 3	70,285	22	0.000308
	Demand GPD			
8	Voltage Level 1	1,270,576	33	0.000026
9	Voltage Level 2	1,080,207	117	0.000108
10	Voltage Level 3	953,091	177	0.000186
11	Total ROA Service		$ 492	
12	Total Surcharge Revenue Collected		$ 24,111	
13	Rounding		26	
14	Total Surcharge Revenue Target		$ 24,137	

(1) A-89 (EAD-5), line 12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 1 - 12 months ending April 30, 2027

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue (1) ($000)	(d) IRM Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 8,829	0.000696
	Secondary Class			
2	Energy-only GS	4,114,839	2,197	0.000534
3	Time-of-Use GSTU	84,563	45	0.000534
4	Demand GSD	2,979,606	1,225	0.000411
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	0	0.000089
6	Voltage Level 2	31,259	3	0.000101
7	Voltage Level 3	632,239	111	0.000175
	Demand GPD			
8	Voltage Level 1	1,167,540	50	0.000043
9	Voltage Level 2	1,453,040	71	0.000049
10	Voltage Level 3	2,414,780	203	0.000084
11	Large Load	7,884,000	339	0.000043
	Time-of-Use GPTU			
12	Voltage Level 1	464,518	20	0.000043
13	Voltage Level 2	496,642	24	0.000049
14	Voltage Level 3	3,312,240	278	0.000084
	Energy Intensive EIP			
15	Voltage Level 1	332,592	14	0.000043
16	Voltage Level 2	53,237	3	0.000049
17	Voltage Level 3	6,737	1	0.000084
	Lighting & Unmetered Class			
18	Metered Lighting GML	10,776	9	0.000800
19	Universal Unmetered Lighting UUL	54,640	196	0.003583
20	Unmetered GU	99,352	23	0.000229
	Self-generation Class			
21	Large Self-generation GSG-2			
22	Voltage Level 1	77,349	3	0.000043
23	Voltage Level 2	77,337	4	0.000049
24	Voltage Level 3	18,615	2	0.000084
25	Total Full Service		$ 13,649	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue (1) ($000)	(h) IRM Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.000696
	Secondary Class			
2	Energy-only GS	18,702	10	0.000534
3	Time-of-Use GSTU	-	-	0.000534
4	Demand GSD	174,288	72	0.000411
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000089
6	Voltage Level 2	1,783	0	0.000101
7	Voltage Level 3	70,285	12	0.000175
	Demand GPD			
8	Voltage Level 1	1,270,576	55	0.000043
9	Voltage Level 2	1,080,207	53	0.000049
10	Voltage Level 3	953,091	80	0.000084
11	Total ROA Service		$ 282	
12	Total Surcharge Revenue Collected		$ 13,931	
13	Rounding		(4)	
14	Total Surcharge Revenue Target		$ 13,927	

(1) A-89 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 2 - 12 months ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-67 (LMC-4)
Page: 32 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue (1) ($000)	(d) IRM Surcharge ($ / kWh)	Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue (1) ($000)	(h) IRM Surcharge ($ / kWh)
	FULL SERVICE					**ROA SERVICE**			
1	Residential Class	12,685,410	$ 16,212	0.001278	1	Residential Class	-	$ -	0.001278
	Secondary Class					Secondary Class			
2	Energy-only GS	4,114,839	4,041	0.000982	2	Energy-only GS	18,702	18	0.000982
3	Time-of-Use GSTU	84,563	83	0.000982	3	Time-of-Use GSTU	-	-	0.000982
4	Demand GSD	2,979,606	2,253	0.000756	4	Demand GSD	174,288	132	0.000756
	Primary Class					Primary Class			
	Energy-only GP					Energy-only GP			
5	Voltage Level 1	3,454	1	0.000164	5	Voltage Level 1	-	-	0.000164
6	Voltage Level 2	31,259	10	0.000322	6	Voltage Level 2	1,783	1	0.000322
7	Voltage Level 3	632,239	204	0.000322	7	Voltage Level 3	70,285	23	0.000322
	Demand GPD					Demand GPD			
8	Voltage Level 1	1,167,540	84	0.000072	8	Voltage Level 1	1,270,576	91	0.000072
9	Voltage Level 2	1,453,040	205	0.000141	9	Voltage Level 2	1,080,207	152	0.000141
10	Voltage Level 3	2,414,780	340	0.000141	10	Voltage Level 3	953,091	134	0.000141
11	Large Load	7,884,000	568	0.000072					
	Time-of-Use GPTU								
12	Voltage Level 1	464,518	33	0.000072	11	Total ROA Service		$ 552	
13	Voltage Level 2	496,642	70	0.000141					
14	Voltage Level 3	3,312,240	467	0.000141	12	Total Surcharge Revenue Collected		$ 25,591	
	Energy Intensive EIP				13	Rounding		6	
15	Voltage Level 1	332,592	24	0.000072	14	Total Surcharge Revenue Target		$ 25,597	
16	Voltage Level 2	53,237	8	0.000141					
17	Voltage Level 3	6,737	1	0.000141					
	Lighting & Unmetered Class								
18	Metered Lighting GML	10,776	16	0.001470					
19	Universal Unmetered Lighting UUL	54,640	360	0.006585					
20	Unmetered GU	99,352	42	0.000420					
	Self-generation Class								
21	Large Self-generation GSG-2								
22	Voltage Level 1	77,349	6	0.000072					
23	Voltage Level 2	77,337	11	0.000141					
24	Voltage Level 3	18,615	3	0.000141					
25	Total Full Service		$ 25,039						

(1) A-89 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Total Revenues

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Date: June 2026

Proposal 4
U-21870 Final Order Model

Line No.	Description	Customers	Sales	Revenue Present	Revenue Proposed	Net Increase / (Decrease) Revenue	Net Increase / (Decrease) Percent
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Mthly	MWh	$000	$000	$000	%
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	1,628,594	12,230,766	$ 2,354,768	$ 2,563,762	$ 208,994	8.9
2	Smart Hours RSH	24,351	177,999	34,358	37,466	3,108	9.0
3	Night Time Savers RPM	16,879	168,382	31,182	34,587	3,406	10.9
4	Non-Transmitting Meters RSM	10,973	108,263	20,935	23,562	2,628	12.6
5	Total Residential Class	1,680,798	12,685,410	$ 2,441,242	$ 2,659,377	$ 218,135	8.9
	Secondary Class						
6	Energy-only GS	204,973	4,114,839	$ 719,808	$ 752,409	$ 32,601	4.5
7	Time-of-Use GSTU	1,891	84,563	14,676	15,437	761	5.2
8	Demand GSD	20,152	2,979,606	446,985	473,358	26,373	5.9
9	Total Secondary	227,015	7,179,008	$ 1,181,468	$ 1,241,204	$ 59,735	5.1
	Primary Class						
10	Energy-only GP	1,360	666,952	$ 79,171	$ 79,859	$ 688	0.9
11	Demand GPD	855	5,035,360	469,921	462,493	(7,428)	(1.6)
12	Time-of-Use GPTU	1,517	4,273,401	458,822	454,414	(4,409)	(1.0)
13	Energy Intensive EIP	17	392,565	30,152	30,636	484	1.6
14	Total Primary	3,748	10,368,279	$ 1,038,067	$ 1,027,402	$ (10,665)	(1.0)
	Lighting & Unmetered Class						
15	Metered Lighting GML	399	10,776	$ 1,622	$ 1,909	$ 286	17.6
16	Universal Unmetered Lighting UUL	4,696	54,640	28,563	32,624	4,061	14.2
17	Unmetered GU	465	99,352	10,837	11,337	500	4.6
18	Total Lighting & Unmetered	5,560	164,769	$ 41,022	$ 45,870	$ 4,848	11.8
	Self-generation Class						
19	Small Self-generation GSG-1	-	-	$ -	$ -	$ -	NA
20	Large Self-generation GSG-2	14	173,301	17,081	17,555	473	2.8
21	Total Self-generation	14	173,301	$ 17,081	$ 17,555	$ 473	2.8
22	Total Full Service	1,917,135	30,570,766	$ 4,718,881	$ 4,991,408	$ 272,527	5.8
	ROA SERVICE						
	Secondary Class						
23	Energy-only GS	85	18,702	$ 1,191	$ 1,317	$ 126	10.6
24	Demand GSD	472	174,288	8,956	10,594	1,638	18.3
25	Total Secondary	556	192,989	$ 10,147	$ 11,911	$ 1,764	17.4
	Primary Class						
26	Energy-only GP	60	72,068	$ 1,817	$ 1,804	$ (14)	(0.8)
27	Demand GPD	356	3,303,873	28,853	31,180	2,327	8.1
28	Total Primary	417	3,375,942	$ 30,671	$ 32,984	$ 2,313	7.5
29	Total ROA Service	973	3,568,931	$ 40,817	$ 44,895	$ 4,078	10.0
30	Total Jurisdictional Service	1,918,108	34,139,697	$ 4,759,698	$ 5,036,302	$ 276,604	5.8
31	Plus: Rounding			-	(1)	2	
32	Total Jurisdictional Revenues			$ 4,759,698	$ 5,036,301	$ 276,603	5.8
33	Less: PSCR Factor Revenues			299,823	299,823	-	
34	Less: DR Surcharge			-	51,821	51,821	
35	Less: IRM Surcharge			-	13,927	13,927	
36	Total Jurisdictional Base Revenues			$ 4,459,875	$ 4,670,730	$ 210,855	4.7
37	Total Jurisdictional Revenues			4,759,698	5,036,301	276,603	5.8
38	Plus: ERC Deferral Surcharge			-	24,325	24,325	
39	Total Jurisdictional Revenues Requested			$ 4,759,698	$ 5,060,626	$ 300,928	6.3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Production & Transmission Revenues

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Line No.	Description	Sales	Revenue Present	Revenue Proposed	Net Increase / (Decrease) Revenue	Net Increase / (Decrease) Percent
	(a)	(b)	(c)	(d)	(e)	(f)
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,230,766	$ 1,258,272	$ 1,283,667	$ 25,396	2.0
2	Smart Hours RSH	177,999	18,266	18,690	424	2.3
3	Night Time Savers RPM	168,382	16,477	17,344	867	5.3
4	Non-Transmitting Meters RSM	108,263	11,213	11,239	26	0.2
5	Total Residential Class	12,685,410	$ 1,304,227	$ 1,330,940	$ 26,713	2.0
	Secondary Class					
6	Energy-only GS	4,114,839	$ 410,783	$ 415,410	$ 4,627	1.1
7	Time-of-Use GSTU	84,563	8,881	9,067	186	2.1
8	Demand GSD	2,979,606	286,430	284,724	(1,706)	(0.6)
9	Total Secondary	7,179,008	$ 706,094	$ 709,201	$ 3,107	0.4
	Primary Class					
10	Energy-only GP	666,952	$ 61,383	$ 62,190	$ 807	1.3
11	Demand GPD	5,035,360	413,307	404,040	(9,268)	(2.2)
12	Time-of-Use GPTU	4,273,401	376,751	373,742	(3,009)	(0.8)
13	Energy Intensive EIP	392,565	27,890	27,465	(425)	(1.5)
14	Total Primary	10,368,279	$ 879,332	$ 867,437	$ (11,895)	(1.4)
	Lighting & Unmetered Class					
15	Metered Lighting GML	10,776	$ 639	$ 584	$ (55)	(8.6)
16	Universal Unmetered Lighting UUL	54,640	3,127	2,800	(327)	(10.4)
17	Unmetered GU	99,352	8,000	7,880	(120)	(1.5)
18	Total Lighting & Unmetered	164,769	$ 11,766	$ 11,264	$ (502)	(4.3)
	Self-generation Class					
19	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
20	Large Self-generation GSG-2	173,301	14,136	14,136	-	-
21	Total Self-generation	173,301	$ 14,136	$ 14,136	$ -	-
22	Total Full Service	30,570,766	$ 2,915,554	$ 2,932,978	$ 17,423	0.6
	ROA SERVICE					
	Secondary Class					
23	Energy-only GS	-	$ -	$ -	$ -	NA
24	Demand GSD	-	-	-	-	NA
25	Total Secondary	-	$ -	$ -	$ -	NA
	Primary Class					
26	Energy-only GP	-	$ -	$ -	$ -	NA
27	Demand GPD	-	-	-	-	NA
28	Total Primary	-	$ -	$ -	$ -	NA
29	Total ROA Service	-	$ -	$ -	$ -	NA
30	Total Jurisdictional Service	30,570,766	$ 2,915,554	$ 2,932,978	$ 17,423	0.6
31	Plus: Rounding		-	(4)	(4)	
32	Total Jurisdictional Base Revenues		$ 2,915,554	$ 2,932,974	$ 17,419	0.6
33	Less: PSCR Factor Revenues		299,823	299,823	-	
34	Less: DR Surcharge		-	51,821	51,821	
35	Less: IRM Surcharge		-	-	-	
36	Total Jurisdictional Base Revenues		$ 2,615,731	$ 2,581,329	$ (34,402)	(1.3)
37	Total Jurisdictional Revenues		2,915,554	2,932,974	17,419	0.6
38	Plus: ERC Deferral Surcharge		-	-	-	
39	Total Jurisdictional Revenues Requested		$ 2,915,554	$ 2,932,974	$ 17,419	0.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Delivery Revenues

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Sales	(c) Revenue Present	(d) Revenue Proposed	(e) Net Increase / (Decrease) Revenue	(f) Net Increase / (Decrease) Percent
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,230,766	$ 1,096,496	$ 1,280,095	$ 183,598	16.7
2	Smart Hours RSH	177,999	16,093	18,776	2,684	16.7
3	Night Time Savers RPM	168,382	14,705	17,243	2,539	17.3
4	Non-Transmitting Meters RSM	108,263	9,722	12,323	2,601	26.8
5	Total Residential Class	12,685,410	$ 1,137,016	$ 1,328,438	$ 191,422	16.8
	Secondary Class					
6	Energy-only GS	4,114,839	$ 309,024	$ 336,999	$ 27,974	9.1
7	Time-of-Use GSTU	84,563	5,795	6,370	575	9.9
8	Demand GSD	2,979,606	160,555	188,634	28,079	17.5
9	Total Secondary	7,179,008	$ 475,374	$ 532,003	$ 56,628	11.9
	Primary Class					
10	Energy-only GP	666,952	$ 17,788	$ 17,669	$ (119)	(0.7)
11	Demand GPD	5,035,360	56,614	58,454	1,840	3.2
12	Time-of-Use GPTU	4,273,401	82,071	80,672	(1,400)	(1.7)
13	Energy Intensive EIP	392,565	2,262	3,171	909	40.2
14	Total Primary	10,368,279	$ 158,735	$ 159,965	$ 1,230	0.8
	Lighting & Unmetered Class					
15	Metered Lighting GML	10,776	$ 983	$ 1,325	$ 341	34.7
16	Universal Unmetered Lighting UUL	54,640	25,436	29,824	4,388	17.3
17	Unmetered GU	99,352	2,836	3,457	620	21.9
18	Total Lighting & Unmetered	164,769	$ 29,256	$ 34,606	$ 5,350	18.3
	Self-generation Class					
19	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
20	Large Self-generation GSG-2	173,301	2,946	3,419	473	16.1
21	Total Self-generation	173,301	$ 2,946	$ 3,419	$ 473	16.1
22	Total Full Service	30,570,766	$ 1,803,326	$ 2,058,430	$ 255,104	14.1
	ROA SERVICE					
	Secondary Class					
23	Energy-only GS	18,702	$ 1,191	$ 1,317	$ 126	10.6
24	Demand GSD	174,288	8,956	10,594	1,638	18.3
25	Total Secondary	192,989	$ 10,147	$ 11,911	$ 1,764	17.4
	Primary Class					
26	Energy-only GP	72,068	$ 1,817	$ 1,804	$ (14)	(0.8)
27	Demand GPD	3,303,873	28,853	31,180	2,327	8.1
28	Total Primary	3,375,942	$ 30,671	$ 32,984	$ 2,313	7.5
29	Total ROA Service	3,568,931	$ 40,817	$ 44,895	$ 4,078	10.0
30	Total Jurisdictional Service	34,139,697	$ 1,844,144	$ 2,103,325	$ 259,181	14.1
31	Plus: Rounding		-	3	3	
32	Total Jurisdictional Base Revenues		$ 1,844,144	$ 2,103,327	$ 259,184	14.1
33	Less: PSCR Factor Revenues		-	-	-	
34	Less: DR Surcharge		-	-	-	
35	Less: IRM Surcharge		-	13,927	13,927	
36	Total Jurisdictional Base Revenues		$ 1,844,144	$ 2,089,400	$ 245,257	13.3
37	Total Jurisdictional Revenues		1,844,144	2,103,327	259,184	14.1
38	Plus: ERC Deferral Surcharge		-	24,325	24,325	
39	Total Jurisdictional Revenues Requested		$ 1,844,144	$ 2,127,652	$ 283,509	15.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Rate Design Targets
($000)

Proposal 4

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Jurisdictional	Residential	Secondary Class GS	Secondary Class GSD	Primary Class GP	Primary Class GPD	Primary Class GPTU	Primary Class EIP	Lighting & Unmetered Class GML	Lighting & Unmetered Class UUL	Lighting & Unmetered Class GU	Self Gen. Class GSG-1	Self Gen. Class GSG-2	Source
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Production														
1	Capacity (SRM)	$ 867,850	$ 438,573	$ 128,665	$ 81,760	$ 17,058	$ 95,864	$ 95,124	$ 6,313	$ 7	$ -	$ 1,676	$ -	$ 2,809	
	Capacity Adjustments [1]														
2	DR Revenue Requirement	(43,454)	(21,342)	(6,325)	(4,132)	(875)	(5,307)	(4,974)	(377)	(4)	(20)	(99)	-	-	WP-LMC-82
3	Self Generation	-	1,245	365	232	48	272	270	18	0	-	5	-	(2,457)	Alloc. Line 1
4	Total Adjustments	(43,454)	(20,097)	(5,960)	(3,899)	(827)	(5,035)	(4,704)	(359)	(4)	(20)	(94)	-	(2,457)	
5	Capacity (SRM) Design Target	$ 824,396	$ 418,477	$ 122,705	$ 77,861	$ 16,231	$ 90,830	$ 90,420	$ 5,954	$ 3	$ (20)	$ 1,582	$ -	$ 353	
6	Energy [2]	$ 1,130,273	$ 475,906	$ 162,466	$ 114,202	$ 25,257	$ 180,648	$ 159,357	$ 14,642	$ 366	$ 1,863	$ 3,773	$ -	$ (8,208)	
	Energy Adjustments [1]														
7	Self Generation	-	(3,431)	(1,171)	(823)	(182)	(1,302)	(1,149)	(106)	(3)	(13)	(27)	-	8,208	Alloc. Line 6
8	Total Adjustments	-	(3,431)	(1,171)	(823)	(182)	(1,302)	(1,149)	(106)	(3)	(13)	(27)	-	8,208	
9	Energy Design Target	$ 1,130,273	$ 472,475	$ 161,295	$ 113,378	$ 25,075	$ 179,346	$ 158,208	$ 14,536	$ 364	$ 1,850	$ 3,746	$ -	$ -	
10	Total Production	$ 1,954,668	$ 890,951	$ 284,001	$ 191,239	$ 41,307	$ 270,175	$ 248,628	$ 20,490	$ 366	$ 1,829	$ 5,329	$ -	$ 353	
11	**Transmission**														
12	Transmission	635,028	296,007	93,071	60,937	13,514	82,308	78,677	6,130	111	427	1,493	-	2,353	
13	Self Generation	-	1,101	346	227	50	306	293	23	0	2	6	-	(2,353)	Alloc. Line 12
14	Transmission Design Target	$ 635,028	$ 297,107	$ 93,417	$ 61,164	$ 13,564	$ 82,614	$ 78,970	$ 6,153	$ 111	$ 428	$ 1,499	$ -	$ -	
	Delivery														
15	Distribution [3]	$ 1,840,453	$ 1,142,598	$ 301,825	$ 185,888	$ 15,980	$ 87,957	$ 68,782	$ 2,228	$ 1,227	$ 28,020	$ 3,344	$ -	$ 2,604	
16	Customer	248,945	187,649	36,001	9,162	2,948	5,702	5,743	144	76	1,326	85	-	109	
17	Subtotal Delivery	2,089,398	1,330,247	337,827	195,050	18,928	93,659	74,525	2,371	1,304	29,347	3,429	-	2,712	
	Credit Adjustments [4]														
18	Substation Credits	$ -	$ 1,801	$ 475	$ 293	$ (8)	$ (1,389)	$ (345)	$ (321)	$ 2	$ 44	$ 5	$ -	$ (557)	WP-LMC-87
19	Life Line Credits	0	(12,477)	4,132	2,585	427	2,585	2,328	168	10	241	-	-	-	WP-LMC-84
20	Total Adjustments	0	(10,676)	4,607	2,878	419	1,196	1,984	(153)	12	285	5	-	(557)	
21	Total Delivery Design Target	$ 2,089,398	$ 1,319,571	$ 342,434	$ 197,928	$ 19,347	$ 94,855	$ 76,508	$ 2,218	$ 1,316	$ 29,632	$ 3,434	$ -	$ 2,155	
22	Total Rate Design Target	$ 4,679,094	$ 2,507,629	$ 719,851	$ 450,331	$ 74,218	$ 447,644	$ 404,106	$ 28,861	$ 1,793	$ 31,889	$ 10,261	$ -	$ 2,508	
23	DR Surcharge	$ 51,821	$ 25,451	$ 7,543	$ 4,927	$ 1,044	$ 6,329	$ 5,932	$ 449	$ 5	$ 24	$ 118	$ -	$ -	WP-LMC-94
24	IRM Surcharge	$ 13,930	$ 8,867	$ 2,252	$ 1,299	$ 125	$ 682	$ 446	$ 19	$ 9	$ 196	$ 23	$ -	$ 11	A-68 (LMC-7)
25	Total Revenue Requirement	$ 4,744,845	$ 2,541,948	$ 729,647	$ 456,558	$ 75,387	$ 454,655	$ 410,484	$ 29,330	$ 1,807	$ 32,109	$ 10,402	$ -	$ 2,519	

Notes
(1) Capacity and energy production costs adjusted to capture elements occurring outside the Cost-of-Service Study.
(2) Includes Non-SRM capacity related costs.
(3) Excludes IRM costs recovered through the IRM surcharge.
(4) Credit adjustments approved in Case No. U-21389

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Summer On-peak (RSP)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	814,657	MWh	@	0.103708	$ 84,486	0.060410	$ 49,214	$ (35,273)
2	Off-peak kWh	3,560,451	MWh	@	0.067729	241,147	0.041347	147,215	(93,932)
	Capacity								
3	On-peak kWh	814,657	MWh	@	0.011465	9,340	0.053506	43,589	34,250
4	Off-peak kWh	3,560,451	MWh	@	0.007706	27,436	0.036622	130,390	102,954
	Winter (Oct. - May)								
5	Non-capacity All kWh	7,855,392	MWh	@	0.060714	476,935	0.033007	259,279	(217,656)
6	Capacity All kWh	7,855,392	MWh	@	0.006004	47,163	0.029234	229,647	182,484
	Provisions								
	Device Cycling								
7	AC Cycling(1)	270,897	Bills	@	(5.00)	(1,354)	(5.00)	(1,354)	-
8	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
9	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
10	Peak Time Rewards	1,016	MWh	@	(1.00)	(1,016)	(0.50)	(508)	508
	Critical Peak Pricing								
11	Critical-peak Charge	266	MWh	@	1.00	266	1.00	266	-
12	Off-peak Credits	41,754	MWh	@	(0.007918)	(331)	(0.006373)	(266)	64
13	Annual PSCR Factor	12,230,766	MWh	@	0.009410	115,092	0.009410	115,092	-
14	Total Production					$ 999,163		$ 972,564	$ (26,599)
	Transmission								
	Summer (June - Sept.)								
15	On-peak kWh	814,657	MWh	@	0.035390	$ 28,831	0.037988	$ 30,947	$ 2,116
16	Off-peak kWh	3,560,451	MWh	@	0.023787	84,692	0.026001	92,574	7,882
	Winter (Oct. - May)								
17	All kWh	7,855,392	MWh	@	0.018533	145,586	0.020756	163,043	17,457
18	Total Transmission					$ 259,109		$ 286,564	$ 27,455
	Delivery								
19	System Access	19,543,128	Bills	@	8.00	$ 156,345	8.00	$ 156,345	$ -
20	Distribution	12,230,766	MWh	@	0.078955	965,686	0.093333	1,141,532	175,846
	Provisions								
21	Senior Citizen (RSC)	4,444,922	Bills	@	(4.00)	(17,780)	(4.00)	(17,780)	-
22	Low Income Credit (LIAC)	66,396	Bills	@	(30.00)	(1,992)	(42.00)	(2,789)	(797)
23	Income Assistance (RIA)	720,358	Bills	@	(8.00)	(5,763)	(8.00)	(5,763)	-
24	Total Delivery					$ 1,096,496		$ 1,271,545	$ 175,049
25	Total Full Service					$ 2,354,768		$ 2,530,673	$ 175,905
	ROA SERVICE								
	Delivery								
26	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
27	Distribution	-	MWh	@	0.078955	-	0.093333	-	-
	Provisions								
28	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
29	Low Income Credit (LIAC)	-	Bills	@	(30.00)	-	(42.00)	-	-
30	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
31	Total Delivery					$ -		$ -	$ -
32	Total Full & ROA Service					$ 2,354,768		$ 2,530,673	$ 175,905

(1) Proposed revenue reflects change to 3 months

0.074701771

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Smart Hours (RSH)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	11,637	MWh	@	0.103708	$ 1,207	0.060410	$ 703	$ (504)
2	Off-peak kWh	54,082	MWh	@	0.067729	3,663	0.041347	2,236	(1,427)
	Capacity								
3	On-peak kWh	11,637	MWh	@	0.011465	133	0.053506	623	489
4	Off-peak kWh	54,082	MWh	@	0.007706	417	0.036622	1,981	1,564
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kWh	17,187	MWh	@	0.068308	1,174	0.038335	659	(515)
6	Off-peak kWh	95,088	MWh	@	0.059219	5,631	0.031989	3,042	(2,589)
	Capacity								
7	On-peak kWh	17,187	MWh	@	0.006611	114	0.033954	584	470
8	Off-peak kWh	95,088	MWh	@	0.005812	553	0.028333	2,694	2,141
	Provisions								
	Device Cycling								
9	AC Cycling(1)	3,816	Bills	@	(5.00)	(19)	(5.00)	(19)	-
10	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
11	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
12	Peak Time Rewards	30	MWh	@	(1.00)	(30)	(0.50)	(15)	15
	Critical Peak Pricing								
13	Critical-peak Charge	5	MWh	@	1.00	5	1.00	5	-
14	Off-peak Credits	1,456	MWh	@	(0.007918)	(12)	(0.006373)	(9)	2
15	Annual PSCR Factor	177,999	MWh	@	0.009410	1,675	0.009410	1,675	-
16	Total Production					$ 14,511		$ 14,157	$ (353)
	Transmission								
	Summer (June - Sept.)								
17	On-peak kWh	11,637	MWh	@	0.035390	$ 412	0.037988	$ 442	$ 30
18	Off-peak kWh	54,082	MWh	@	0.023787	1,286	0.026001	1,406	120
	Winter (Oct. - May)								
19	On-peak kWh	17,187	MWh	@	0.020408	351	0.024106	414	64
20	Off-peak kWh	95,088	MWh	@	0.017940	1,706	0.020116	1,913	207
21	Total Transmission					$ 3,755		$ 4,175	$ 420
	Delivery								
22	System Access	292,217	Bills	@	8.00	$ 2,338	8.00	$ 2,338	$ -
23	Distribution	177,999	MWh	@	0.078955	14,054	0.093333	16,613	2,559
	Provisions								
24	Senior Citizen (RSC)	48,048	Bills	@	(4.00)	(192)	(4.00)	(192)	-
25	Low Income Credit (LIAC)	-	Bills	@	(30.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	13,378	Bills	@	(8.00)	(107)	(8.00)	(107)	-
27	Total Delivery					$ 16,093		$ 18,652	$ 2,559
28	Total Full Service					$ 34,358		$ 36,984	$ 2,626
	ROA SERVICE								
	Delivery								
29	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
30	Distribution	-	MWh	@	0.078955	-	0.093333	-	-
	Provisions								
31	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
32	Low Income Credit (LIAC)	-	Bills	@	(30.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
34	Total Delivery					$ -		$ -	$ -
35	Total Full & ROA Service					$ 34,358		$ 36,984	$ 2,626

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Nighttime Savers (RPM)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	9,384	MWh	@	0.103708	$ 973	0.060410	$ 567	$ (406)
2	Off-peak kWh	19,685	MWh	@	0.075937	1,495	0.046196	909	(585)
3	Super Off-peak kWh	33,466	MWh	@	0.060380	2,021	0.037381	1,251	(770)
	Capacity								
4	On-peak kWh	9,384	MWh	@	0.011465	108	0.053506	502	395
5	Off-peak kWh	19,685	MWh	@	0.008693	171	0.040916	805	634
6	Super Off-peak kWh	33,466	MWh	@	0.005292	177	0.033109	1,108	931
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	13,591	MWh	@	0.068308	928	0.038335	521	(407)
8	Off-peak kWh	33,262	MWh	@	0.066685	2,218	0.035960	1,196	(1,022)
9	Super Off-peak kWh	58,994	MWh	@	0.052649	3,106	0.028890	1,704	(1,402)
	Capacity								
10	On-peak kWh	13,591	MWh	@	0.006611	90	0.033954	461	372
11	Off-peak kWh	33,262	MWh	@	0.006392	213	0.031850	1,059	847
12	Super Off-peak kWh	58,994	MWh	@	0.004585	270	0.025588	1,510	1,239
	Provisions								
	Device Cycling								
13	AC Cycling(1)	4,141	Bills	@	(5.00)	(21)	(5.00)	(21)	-
14	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
15	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
16	Peak Time Rewards	23	MWh	@	(1.00)	(23)	(0.50)	(11)	11
	Critical Peak Pricing								
17	Critical-peak Charge	1	MWh	@	1.00	1	1.00	1	-
18	Off-peak Credits	1,417	MWh	@	(0.007918)	(11)	(0.006373)	(9)	2
19	Annual PSCR Factor	168,382	MWh	@	0.009410	1,584	0.009410	1,584	-
20	Total Production					$ 13,301		$ 13,139	$ (162)
	Transmission								
	Summer (June - Sept.)								
21	On-peak kWh	9,384	MWh	@	0.035390	$ 332	0.037988	$ 356	$ 24
22	Off-peak kWh	19,685	MWh	@	0.026835	528	0.029049	572	44
23	Super Off-peak kWh	33,466	MWh	@	0.016336	547	0.023506	787	240
	Winter (Oct. - May)								
24	On-peak kWh	13,591	MWh	@	0.020408	277	0.024106	328	50
25	Off-peak kWh	33,262	MWh	@	0.019733	656	0.022613	752	96
26	Super Off-peak kWh	58,994	MWh	@	0.014153	835	0.018167	1,072	237
27	Total Transmission					$ 3,176		$ 3,866	$ 691
	Delivery								
28	System Access	202,551	Bills	@	8.00	$ 1,620	8.00	$ 1,620	$ -
29	Separately Metered EV Charger	295	Bills	@	(8.00)	$ (2)	(8.00)	$ (2)	$ -
30	Distribution	168,382	MWh	@	0.078955	13,295	0.093333	15,716	2,421
	Provisions								
31	Senior Citizen (RSC)	41,852	Bills	@	(4.00)	(167)	(4.00)	(167)	-
32	Low Income Credit (LIAC)	-	Bills	@	(30.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	5,053	Bills	@	(8.00)	(40)	(8.00)	(40)	-
34	Total Delivery					$ 14,705		$ 17,126	$ 2,421
35	Total Full Service					$ 31,182		$ 34,132	$ 2,950
	ROA SERVICE								
	Delivery								
36	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
37	Distribution	-	MWh	@	0.078955	-	0.093333	-	-
	Provisions								
38	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
39	Low Income Credit (LIAC)	-	Bills	@	(30.00)	-	(42.00)	-	-
40	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
41	Total Delivery					$ -		$ -	$ -
42	Total Full & ROA Service					$ 31,182		$ 34,132	$ 2,950

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Non-Transmitting Meters (RSM)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	First 600 kWh	23,089	MWh	@	0.060714	$ 1,402	0.033007	$ 762	$ (640)
2	Excess kWh	14,767	MWh	@	0.103708	1,531	0.060410	892	(639)
	Capacity								
3	First 600 kWh	23,089	MWh	@	0.006004	139	0.029234	675	536
4	Excess kWh	14,767	MWh	@	0.011465	169	0.053506	790	621
	Winter (Oct. - May)								
5	Non-capacity All kWh	70,407	MWh	@	0.060714	4,275	0.033007	2,324	(1,951)
6	Capacity All kWh	70,407	MWh	@	0.006004	423	0.029234	2,058	1,636
7	Annual PSCR Factor	108,263	MWh	@	0.009410	1,019	0.009410	1,019	-
8	Total Production					$ 8,957		$ 8,520	$ (437)
	Transmission								
	Summer (June - Sept.)								
9	First 600 kWh	23,089	MWh	@	0.018533	$ 428	0.020756	$ 479	$ 51
10	Excess kWh	14,767	MWh	@	0.035390	523	0.037988	561	38
	Winter (Oct. - May)								
11	All kWh	70,407	MWh	@	0.018533	1,305	0.020756	1,461	156
12	Total Transmission					$ 2,255		$ 2,502	$ 246
	Delivery								
13	System Access	131,680	Bills	@	8.00	$ 1,053	8.00	$ 1,053	$ -
14	Opt-out Fee	100,852	Bills	@	3.00	303	12.61	1,272	969
15	Distribution	108,263	MWh	@	0.078955	8,548	0.093333	10,104	1,557
	Provisions								
16	Senior Citizen (RSC)	36,309	Bills	@	(4.00)	(145)	(4.00)	(145)	-
17	Low Income Credit (LIAC)	-	Bills	@	(30.00)	-	(42.00)	-	-
18	Income Assistance (RIA)	4,599	Bills	@	(8.00)	(37)	(8.00)	(37)	-
19	Total Delivery					$ 9,722		$ 12,248	$ 2,526
20	Total Full Service					$ 20,935		$ 23,269	$ 2,335
	ROA SERVICE								
	Delivery								
21	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
22	Opt-out Fee	-	Bills	@	3.00	-	12.61	-	-
23	Distribution	-	MWh	@	0.078955	-	0.093333	-	-
	Provisions								
24	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
25	Low Income Credit (LIAC)	-	Bills	@	(30.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
27	Total Delivery					$ -		$ -	$ -
28	Total Full & ROA Service					$ 20,935		$ 23,269	$ 2,335

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Energy-only (GS)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	1,447,697	MWh	@	0.072639	$ 105,159	0.046363	$ 67,119	$ (38,040)
2	Capacity All kWh	1,447,697	MWh	@	0.007743	11,209	0.035056	50,750	39,541
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,667,142	MWh	@	0.059380	158,376	0.034013	90,716	(67,659)
4	Capacity All kWh	2,667,142	MWh	@	0.005420	14,455	0.025987	69,310	54,855
5	Annual PSCR Factor	4,114,839	MWh	@	0.009410	38,721	0.009410	38,721	-
6	Total Production					$ 327,920		$ 316,616	$ (11,303)
	Transmission								
	Summer (June - Sept.)								
7	All kWh	1,447,697	MWh	@	0.025000	$ 36,192	0.026688	$ 38,636	$ 2,444
	Winter (Oct. - May)								
8	All kWh	2,667,142	MWh	@	0.017499	46,671	0.019784	52,766	6,095
9	Total Transmission					$ 82,864		$ 91,403	$ 8,539
	Delivery								
10	System Access	2,459,675	Bills	@	20.00	$ 49,193	20.00	$ 49,193	$ -
11	Distribution	4,114,839	MWh	@	0.063166	259,919	0.069433	285,704	25,784
	Provisions								
12	Education GEI	95,811	MWh	@	(0.000923)	(88)	(0.001000)	(96)	(7)
13	Total Delivery					$ 309,024		$ 334,801	$ 25,777
14	Total Full Service					$ 719,808		$ 742,820	$ 23,013
	ROA SERVICE								
	Delivery								
15	System Access	1,014	Bills	@	20.00	$ 20	20.00	$ 20	$ -
16	Distribution	18,702	MWh	@	0.063166	1,181	0.069433	1,299	117
	Provisions								
17	Education GEI	11,475	MWh	@	(0.000923)	(11)	(0.001000)	(11)	(1)
18	Total Delivery					$ 1,191		$ 1,307	$ 116
19	Total Full & ROA Service					$ 720,999		$ 744,128	$ 23,129

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Time-of-Use (GSTU)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	14,873	MWh	@	0.104236	$ 1,550	0.062830	$ 934	$ (616)
2	Mid-peak kWh	11,717	MWh	@	0.076824	900	0.048934	573	(327)
3	Off-peak kWh	4,487	MWh	@	0.058953	265	0.036694	165	(100)
	Capacity								
4	On-peak kWh	14,873	MWh	@	0.009395	140	0.047982	714	574
5	Mid-peak kWh	11,717	MWh	@	0.007806	91	0.037369	438	346
6	Off-peak kWh	4,487	MWh	@	0.005037	23	0.028063	126	103
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	25,578	MWh	@	0.065715	1,681	0.037107	949	(732)
8	Off-peak kWh	27,907	MWh	@	0.052389	1,462	0.030029	838	(624)
	Capacity								
9	On-peak kWh	25,578	MWh	@	0.005876	150	0.028428	727	577
10	Off-peak kWh	27,907	MWh	@	0.004390	123	0.022961	641	518
	Provisions								
11	Interruptible (GSI)	-	MWh	@	(0.021295)	-	(0.021695)	-	-
12	Annual PSCR Factor	84,563	MWh	@	0.009410	796	0.009410	796	-
13	Total Production					$ 7,180		$ 6,901	$ (280)
	Transmission								
	Summer (June - Sept.)								
14	On-peak kWh	14,873	MWh	@	0.030333	$ 451	0.036529	$ 543	$ 92
15	Mid-peak kWh	11,717	MWh	@	0.025203	295	0.028449	333	38
16	Off-peak kWh	4,487	MWh	@	0.016265	73	0.021365	96	23
	Winter (Oct. - May)								
17	On-peak kWh	25,578	MWh	@	0.018972	485	0.021643	554	68
18	Off-peak kWh	27,907	MWh	@	0.014174	396	0.017480	488	92
19	Total Transmission					$ 1,700		$ 2,014	$ 314
	Delivery								
20	System Access	22,689	Bills	@	20.00	$ 454	20.00	$ 454	$ -
21	Distribution	84,563	MWh	@	0.063166	5,342	0.069433	5,871	530
	Provisions								
22	Education GEI	-	MWh	@	(0.000923)	-	(0.001000)	-	-
23	Total Delivery					$ 5,795		$ 6,325	$ 530
24	Total Full Service					$ 14,676		$ 15,240	$ 564

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Demand (GSD)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Peak kW	2,893	MW	@	18.04	$ 52,194	6.10	$ 17,632	$ (34,562)
2	All kWh	1,048,776	MWh	@	0.033424	35,054	0.032526	34,112	(942)
	Capacity								
3	Peak kW	2,893	MW	@	2.17	6,278	10.17	29,425	23,147
4	All kWh	1,048,776	MWh	@	-	-	-	-	-
	Winter (Oct. - May)								
	Non-capacity								
5	Peak kW	5,338	MW	@	8.54	45,593	2.89	15,402	(30,191)
6	All kWh	1,930,830	MWh	@	0.027323	52,756	0.023861	46,072	(6,684)
	Capacity								
7	Peak kW	5,338	MW	@	1.93	10,310	9.05	48,326	38,016
8	All kWh	1,930,830	MWh	@	-	-	-	-	-
9	Power Factor Adjustment					161		269	108
	Provisions								
10	Interruptible (GSI)-Summer	29	MW	@	(8.50)	(247)	(8.50)	(247)	-
11	Interruptible (GSI)-Winter	53	MW	@	(7.50)	(398)	(7.50)	(398)	-
12	Annual PSCR Factor	2,979,606	MWh	@	0.009410	28,038	0.009410	28,038	-
13	Total Production					$ 229,741		$ 218,633	$ (11,108)
	Transmission								
	Summer (June - Sept.)								
14	Peak kW	2,893	MW	@	7.42	$ 21,454	8.00	$ 23,147	$ 1,693
	Winter (Oct. - May)								
15	Peak kW	5,338	MW	@	6.60	35,235	7.12	38,017	2,781
16	Total Transmission					$ 56,689		$ 61,164	$ 4,475
	Delivery								
17	System Access	241,823	Bills	@	30.00	$ 7,255	30.00	$ 7,255	$ -
18	Peak kW	8,231	MW	@	1.00	8,231	1.00	8,231	-
19	Distribution	2,979,606	MWh	@	0.048648	144,950	0.057650	171,774	26,823
20	Power Factor Adjustment					216		254	38
	Provisions								
21	Education GEI	131,112	MWh	@	(0.000745)	(98)	(0.000820)	(107)	(10)
22	Total Delivery					$ 160,555		$ 187,406	$ 26,851
23	Total Full Service					$ 446,985		$ 467,203	$ 20,218
	ROA SERVICE								
	Delivery								
24	System Access	5,663	Bills	@	30.00	$ 170	30.00	$ 170	$ -
25	Peak kW	344	MW	@	1.00	344	1.00	344	-
26	Distribution	174,288	MWh	@	0.048648	8,479	0.057650	10,048	1,569
27	Power Factor Adjustment					13		16	2
	Provisions								
28	Education GEI	68,199	MWh	@	(0.000745)	(51)	(0.000820)	(56)	(5)
29	Total Delivery					$ 8,956		$ 10,522	$ 1,566
30	Total Full & ROA Service					$ 455,940		$ 477,725	$ 21,785

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 1 (GP VL 1)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	1,101	MWh	@	0.064501	$ 71	0.043974	$ 48	$ (23)
2	Capacity All kWh	1,101	MWh	@	0.006228	7	0.027595	30	24
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,353	MWh	@	0.052728	124	0.032261	76	(48)
4	Capacity All kWh	2,353	MWh	@	0.004359	10	0.021049	50	39
5	Power Factor Adjustment					3		3	(0)
6	Annual PSCR Factor	3,454	MWh	@	0.009410	33	0.009410	33	-
7	Total Production					$ 248		$ 240	$ (8)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	1,101	MWh	@	0.022500	$ 25	0.023364	$ 26	$ 1
	Winter (Oct. - May)								
9	All kWh	2,353	MWh	@	0.015749	37	0.017822	42	5
10	Total Transmission					$ 62		$ 68	$ 6
	Delivery								
11	System Access	49	Bills	@	100.00	$ 5	100.00	$ 5	$ -
12	Distribution	3,454	MWh	@	0.002918	10	0.006957	24	14
13	Substation Ownership Credit	700	MWh	@	(0.001438)	(1)	(0.004093)	(3)	(2)
14	Power Factor Adjustment					0		0	0
	Provisions								
15	Education GEI	-	MWh	@	(0.000558)	-	(0.000578)	-	-
16	Total Delivery					$ 14		$ 26	$ 12
17	Total Full Service					$ 324		$ 334	$ 10
	ROA SERVICE								
	Delivery								
18	System Access	-	Bills	@	100.00	$ -	100.00	$ -	$ -
19	Distribution	-	MWh	@	0.002918	-	0.006957	-	-
20	Substation Ownership Credit	-	MWh	@	(0.001438)	-	(0.004093)	-	-
21	Power Factor Adjustment					-		-	-
	Provisions								
22	Education GEI	-	MWh	@	(0.000558)	-	(0.000578)	-	-
23	Total Delivery					$ -		$ -	$ -
24	Total Full & ROA Service					$ 324		$ 334	$ 10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 2 (GP VL 2)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate	Present Revenue	Proposed Rate	Proposed Revenue	Net Increase / (Decrease)
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
					$/unit	$000	$/unit	$000	$000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	9,485	MWh	@	0.065275	$ 619	0.044489	$ 422	$ (197)
2	Capacity All kWh	9,485	MWh	@	0.006319	60	0.027998	266	206
	Winter (Oct. - May)								
3	Non-capacity All kWh	21,775	MWh	@	0.053361	1,162	0.032638	711	(451)
4	Capacity All kWh	21,775	MWh	@	0.004423	96	0.021357	465	369
5	Power Factor Adjustment					51		49	(2)
6	Annual PSCR Factor	31,259	MWh	@	0.009410	294	0.009410	294	-
7	Total Production					$ 2,282		$ 2,206	$ (76)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	9,485	MWh	@	0.022831	$ 217	0.023706	$ 225	$ 8
	Winter (Oct. - May)								
9	All kWh	21,775	MWh	@	0.015981	348	0.018083	394	46
10	Total Transmission					$ 565		$ 619	$ 54
	Delivery								
11	System Access	435	Bills	@	100.00	$ 43	100.00	$ 43	$ -
12	Distribution	31,259	MWh	@	0.010731	335	0.010996	344	8
13	Substation Ownership Credit	6,580	MWh	@	(0.001925)	(13)	(0.004513)	(30)	(17)
14	Power Factor Adjustment					8		8	(0)
	Provisions								
15	Education GEI	-	MWh	@	(0.000558)	-	(0.000578)	-	-
16	Total Delivery					$ 375		$ 366	$ (9)
17	Total Full Service					$ 3,221		$ 3,191	$ (31)
	ROA SERVICE								
	Delivery								
18	System Access	24	Bills	@	100.00	$ 2	100.00	$ 2	$ -
19	Distribution	1,783	MWh	@	0.010731	19	0.010996	20	0
20	Substation Ownership Credit	-	MWh	@	(0.001925)	-	(0.004513)	-	-
21	Power Factor Adjustment					(0)		(0)	(0)
	Provisions								
22	Education GEI	-	MWh	@	(0.000558)	-	(0.000578)	-	-
23	Total Delivery					$ 21		$ 22	$ 0
24	Total Full & ROA Service					$ 3,243		$ 3,212	$ (30)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 3 (GP VL 3)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate	Present Revenue	Proposed Rate	Proposed Revenue	Net Increase / (Decrease)
					(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
					$/unit	$000	$/unit	$000	$000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	221,271	MWh	@	0.065920	$ 14,586	0.044937	$ 9,943	$ (4,643)
2	Capacity All kWh	221,271	MWh	@	0.006408	1,418	0.028442	6,293	4,876
	Winter (Oct. - May)								
3	Non-capacity All kWh	410,967	MWh	@	0.053888	22,146	0.032967	13,548	(8,598)
4	Capacity All kWh	410,967	MWh	@	0.004485	1,843	0.021696	8,916	7,073
5	Power Factor Adjustment					502		486	(16)
6	Annual PSCR Factor	632,239	MWh	@	0.009410	5,949	0.009410	5,949	-
7	Total Production					$ 46,445		$ 45,136	$ (1,308)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	221,271	MWh	@	0.023151	$ 5,123	0.024082	$ 5,329	$ 206
	Winter (Oct. - May)								
9	All kWh	410,967	MWh	@	0.016204	6,659	0.018370	7,549	890
10	Total Transmission					$ 11,782		$ 12,878	$ 1,096
	Delivery								
11	System Access	15,834	Bills	@	100.00	$ 1,583	100.00	$ 1,583	$ -
12	Distribution	632,239	MWh	@	0.024779	15,666	0.024415	15,436	(231)
13	Power Factor Adjustment					197		194	(3)
	Provisions								
14	Education GEI	85,102	MWh	@	(0.000558)	(47)	(0.000578)	(49)	(2)
15	Total Delivery					$ 17,399		$ 17,164	$ (235)
16	Total Full Service					$ 75,626		$ 75,178	$ (448)
	ROA SERVICE								
	Delivery								
17	System Access	696	Bills	@	100.00	$ 70	100.00	$ 70	$ -
18	Distribution	70,285	MWh	@	0.024779	1,742	0.024415	1,716	(26)
19	Power Factor Adjustment					5		5	(0)
	Provisions								
20	Education GEI	36,890	MWh	@	(0.000558)	(21)	(0.000578)	(21)	(1)
21	Total Delivery					$ 1,796		$ 1,770	$ (26)
22	Total Full & ROA Service					$ 77,422		$ 76,948	$ (474)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 1 (GPD VL 1)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	668	MW	@	14.98	$ 10,004	5.96	$ 3,979	$ (6,025)
2	On-peak kWh	86,218	MWh	@	0.042727	3,684	0.040427	3,486	(198)
3	Off-peak kWh	296,066	MWh	@	0.027682	8,196	0.026219	7,762	(433)
4	Capacity On-peak kW	668	MW	@	2.17	1,446	10.06	6,719	5,273
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,369	MW	@	12.94	17,723	5.15	7,050	(10,673)
6	On-peak kWh	179,258	MWh	@	0.029145	5,225	0.025351	4,544	(680)
7	Off-peak kWh	605,998	MWh	@	0.025104	15,213	0.022012	13,339	(1,873)
8	Capacity On-peak kW	1,369	MW	@	2.01	2,750	9.33	12,777	10,027
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	60	MW	@	(8.50)	(514)	(8.50)	(514)	-
11	Winter Contracted kW	121	MW	@	(7.50)	(905)	(7.50)	(905)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.029172	-	0.029081	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.026113	-	0.026985	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.027987	-	-
16	Summer Transmission	-	MWh		-	-	0.015940	-	-
17	Winter Capacity	-	MWh		-	-	0.025248	-	-
18	Winter Transmission	-	MWh		-	-	0.014813	-	-
19	Critical Peak Event	-	MWh		-	-	1.00	-	-
20	Power Factor Adjustment					(132)		(122)	10
21	Annual PSCR Factor	1,167,540	MWh	@	0.009410	10,987	0.009410	10,987	-
22	Total Production					$ 73,676		$ 69,103	$ (4,573)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	668	MW	@	8.63	$ 5,764	9.13	$ 6,094	$ 330
	Winter (Oct. - May)								
24	On-peak kW	1,369	MW	@	8.04	11,002	8.50	11,632	630
25	Total Transmission					$ 16,766		$ 17,725	$ 959
	Delivery								
26	System Access	267	Bills	@	200.00	$ 53	200.00	$ 53	$ -
27	Maximum kW	2,528	MW	@	1.02	2,572	2.37	5,996	3,424
28	Substation Ownership	42	MW	@	(0.66)	(28)	(1.82)	(76)	(48)
29	Distribution	1,167,540	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(5)		(12)	(7)
	Provisions								
31	Education GEI	-	MWh	@	(0.000194)	-	(0.000205)	-	-
32	Total Delivery					$ 2,592		$ 5,961	$ 3,369
33	Total Full Service					$ 93,034		$ 92,789	$ (245)
	ROA SERVICE								
	Delivery								
34	System Access	169	Bills	@	200.00	$ 34	200.00	$ 34	$ -
35	Maximum kW	2,403	MW	@	1.02	2,445	2.37	5,700	3,255
36	Substation Ownership	196	MW	@	(0.66)	(130)	(1.82)	(356)	(226)
37	Distribution	1,270,576	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					(6)		(14)	(8)
	Provisions								
39	Education GEI	2,675	MWh	@	(0.000194)	(1)	(0.000205)	(1)	(0)
40	Total Delivery					$ 2,342		$ 5,364	$ 3,022
41	Total Full & ROA Service					$ 95,376		$ 98,153	$ 2,777

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 2 (GPD VL 2)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	886	MW	@	15.16	$ 13,428	6.03	$ 5,340	$ (8,088)
2	On-peak kWh	121,063	MWh	@	0.043240	5,235	0.040900	4,951	(283)
3	Off-peak kWh	357,634	MWh	@	0.028014	10,019	0.026526	9,486	(532)
4	Capacity On-peak kW	886	MW	@	2.20	1,946	10.21	9,042	7,096
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,801	MW	@	13.10	23,591	5.21	9,381	(14,210)
6	On-peak kWh	240,894	MWh	@	0.029495	7,105	0.025648	6,178	(927)
7	Off-peak kWh	733,449	MWh	@	0.025405	18,633	0.022270	16,334	(2,300)
8	Capacity On-peak kW	1,801	MW	@	2.04	3,670	9.47	17,051	13,381
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	40	MW	@	(8.50)	(343)	(8.50)	(343)	-
11	Winter Contracted kW	81	MW	@	(7.50)	(608)	(7.50)	(608)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.031540	-	0.031449	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.028315	-	0.029198	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.030044	-	-
16	Summer Transmission	-	MWh		-	-	0.017130	-	-
17	Winter Capacity	-	MWh		-	-	0.027129	-	-
18	Winter Transmission	-	MWh		-	-	0.008416	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					(111)		(103)	8
21	Annual PSCR Factor	1,453,040	MWh	@	0.009410	13,673	0.009410	13,673	-
22	Total Production					$ 96,239		$ 90,384	$ (5,855)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	886	MW	@	8.76	$ 7,757	9.26	$ 8,200	$ 443
	Winter (Oct. - May)								
24	On-peak kW	1,801	MW	@	8.15	14,684	8.62	15,523	839
25	Total Transmission					$ 22,441		$ 23,723	$ 1,282
	Delivery								
26	System Access	721	Bills	@	200.00	$ 144	200.00	$ 144	$ -
27	Maximum kW	3,094	MW	@	3.50	10,822	3.61	11,178	356
28	Substation Ownership	269	MW	@	(0.83)	(224)	(1.93)	(520)	(296)
29	Distribution	1,453,040	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(14)		(14)	(0)
	Provisions								
31	Education GEI	29,734	MWh	@	(0.000194)	(6)	(0.000205)	(6)	(0)
32	Total Delivery					$ 10,723		$ 10,782	$ 59
33	Total Full Service					$ 129,403		$ 124,888	$ (4,514)
	ROA SERVICE								
	Delivery								
34	System Access	453	Bills	@	200.00	$ 91	200.00	$ 91	$ -
35	Maximum kW	2,306	MW	@	3.50	8,066	3.61	8,331	265
36	Substation Ownership	298	MW	@	(0.83)	(248)	(1.93)	(576)	(328)
37	Distribution	1,080,207	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					16		16	(0)
	Provisions								
39	Education GEI	66,701	MWh	@	(0.000194)	(13)	(0.000205)	(14)	(1)
40	Total Delivery					$ 7,912		$ 7,848	$ (63)
41	Total Full & ROA Service					$ 137,314		$ 132,737	$ (4,578)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 3 (GPD VL 3)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	1,514	MW	@	15.31	$ 23,180	6.09	$ 9,219	$ (13,960)
2	On-peak kWh	209,315	MWh	@	0.043667	9,140	0.041312	8,647	(493)
3	Off-peak kWh	587,189	MWh	@	0.028291	16,612	0.026793	15,733	(880)
4	Capacity On-peak kW	1,514	MW	@	2.23	3,373	10.37	15,701	12,328
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	3,075	MW	@	13.23	40,683	5.26	16,181	(24,502)
6	On-peak kWh	417,471	MWh	@	0.029787	12,435	0.025907	10,815	(1,620)
7	Off-peak kWh	1,200,805	MWh	@	0.025656	30,808	0.022495	27,012	(3,797)
8	Capacity On-peak kW	3,075	MW	@	2.07	6,354	9.62	29,579	23,224
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	4	MW	@	(8.50)	(34)	(8.50)	(34)	-
11	Winter Contracted kW	8	MW	@	(7.50)	(57)	(7.50)	(57)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.032871	-	0.033010	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.030146	-	0.031900	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.031287	-	-
16	Summer Transmission	-	MWh		-	-	0.017876	-	-
17	Winter Capacity	-	MWh		-	-	0.028277	-	-
18	Winter Transmission	-	MWh		-	-	0.016640	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					98		91	(7)
21	Annual PSCR Factor	2,414,780	MWh	@	0.009410	22,723	0.009410	22,723	-
22	Total Production					$ 165,315		$ 155,610	$ (9,706)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	1,514	MW	@	8.88	$ 13,444	9.41	$ 14,239	$ 794
	Winter (Oct. - May)								
24	On-peak kW	3,075	MW	@	8.27	25,426	8.76	26,928	1,502
25	Total Transmission					$ 38,870		$ 41,166	$ 2,296
	Delivery								
26	System Access	9,273	Bills	@	200.00	$ 1,855	200.00	$ 1,855	$ -
27	Maximum kW	5,899	MW	@	7.02	41,437	6.68	39,414	(2,023)
28	Distribution	2,414,780	MWh	@	-	-	-	-	-
29	Power Factor Adjustment					29		27	(1)
	Provisions								
30	Education GEI	110,078	MWh	@	(0.000194)	(21)	(0.000205)	(23)	(1)
31	Total Delivery					$ 43,299		$ 41,273	$ (2,026)
32	Total Full Service					$ 247,485		$ 238,049	$ (9,435)
	ROA SERVICE								
	Delivery								
33	System Access	3,656	Bills	@	200.00	$ 731	200.00	$ 731	$ -
34	Maximum kW	2,542	MW	@	7.02	17,858	6.68	16,986	(872)
35	Distribution	953,091	MWh	@	-	-	-	-	-
36	Power Factor Adjustment					39		37	(2)
	Provisions								
37	Education GEI	149,120	MWh	@	(0.000194)	(29)	(0.000205)	(31)	(2)
38	Total Delivery					$ 18,599		$ 17,724	$ (876)
39	Total Full & ROA Service					$ 266,084		$ 255,773	$ (10,311)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 1 (GPTU VL 1)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
Page: 18 of 31
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	13,186	MWh	@	0.095630	$ 1,261	0.061877	$ 816	$ (445)
2	Mid-peak kWh	17,748	MWh	@	0.082506	1,464	0.055068	977	(487)
3	Low-peak kWh	48,608	MWh	@	0.064588	3,140	0.044513	2,164	(976)
4	Off-peak kWh	86,924	MWh	@	0.050483	4,388	0.033174	2,884	(1,505)
	Capacity								
5	High-peak kWh	13,186	MWh	@	0.007064	93	0.035267	465	372
6	Mid-peak kWh	17,748	MWh	@	0.006743	120	0.031400	557	438
7	Low-peak kWh	48,608	MWh	@	0.005416	263	0.025306	1,230	967
8	Off-peak kWh	86,924	MWh	@	0.003658	318	0.018927	1,645	1,327
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	26,006	MWh	@	0.063021	1,639	0.039842	1,036	(603)
10	Mid-peak kWh	36,415	MWh	@	0.058360	2,125	0.036938	1,345	(780)
11	Off-peak kWh	235,629	MWh	@	0.049251	11,605	0.031011	7,307	(4,298)
	Capacity								
12	High-peak kWh	26,006	MWh	@	0.004532	118	0.022720	591	473
13	Mid-peak kWh	36,415	MWh	@	0.004530	165	0.021035	766	601
14	Off-peak kWh	235,629	MWh	@	0.003899	919	0.017499	4,123	3,205
15	Power Factor Adjustment					45		42	(3)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	464,518	MWh	@	0.009410	4,371	0.009410	4,371	-
19	Total Production					$ 32,033		$ 30,320	$ (1,714)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	13,186	MWh	@	0.026667	$ 352	0.030861	$ 407	$ 55
21	Mid-peak kWh	17,748	MWh	@	0.025457	452	0.027477	488	36
22	Low-peak kWh	48,608	MWh	@	0.020445	994	0.022144	1,076	83
23	Off-peak kWh	86,924	MWh	@	0.013810	1,200	0.016563	1,440	239
24	Winter (Oct. - May)								
25	High-peak kWh	26,006	MWh	@	0.017109	445	0.019881	517	72
26	Mid-peak kWh	36,415	MWh	@	0.017102	623	0.018407	670	48
27	Off-peak kWh	235,629	MWh	@	0.014719	3,468	0.015313	3,608	140
28	Total Transmission					$ 7,534		$ 8,206	$ 673
	Delivery								
29	System Access	280	Bills	@	200.00	$ 56	200.00	$ 56	$ -
30	Maximum kW	1,315	MW	@	1.02	1,338	2.37	3,119	1,781
31	Substation Ownership	-	MW	@	(0.66)	-	(1.82)	-	-
32	Distribution	464,518	MWh	@	-	-	-	-	-
33	Power Factor Adjustment					2		5	3
	Provisions								
34	Education GEI	39,403	MWh	@	(0.000194)	(8)	(0.000205)	(8)	(0)
35	Total Delivery					$ 1,388		$ 3,172	$ 1,784
36	Total Full Service					$ 40,955		$ 41,698	$ 743

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 2 (GPTU VL 2)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
Page: 19 of 31
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	16,699	MWh	@	0.096778	$ 1,616	0.062601	$ 1,045	$ (571)
2	Mid-peak kWh	22,367	MWh	@	0.083496	1,868	0.055712	1,246	(621)
3	Low-peak kWh	51,905	MWh	@	0.065363	3,393	0.045034	2,337	(1,055)
4	Off-peak kWh	84,694	MWh	@	0.051088	4,327	0.033562	2,843	(1,484)
	Capacity								
5	High-peak kWh	16,699	MWh	@	0.007168	120	0.035782	598	478
6	Mid-peak kWh	22,367	MWh	@	0.006842	153	0.031859	713	560
7	Low-peak kWh	51,905	MWh	@	0.005495	285	0.025675	1,333	1,047
8	Off-peak kWh	84,694	MWh	@	0.003712	314	0.019204	1,626	1,312
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	32,702	MWh	@	0.063777	2,086	0.040309	1,318	(767)
10	Mid-peak kWh	44,338	MWh	@	0.059061	2,619	0.037370	1,657	(962)
11	Off-peak kWh	243,938	MWh	@	0.049842	12,158	0.031374	7,653	(4,505)
	Capacity								
12	High-peak kWh	32,702	MWh	@	0.004599	150	0.023051	754	603
13	Mid-peak kWh	44,338	MWh	@	0.004597	204	0.021342	946	742
14	Off-peak kWh	243,938	MWh	@	0.003956	965	0.017754	4,331	3,366
15	Power Factor Adjustment					(13)		(12)	1
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	496,642	MWh	@	0.009410	4,673	0.009410	4,673	-
19	Total Production					$ 34,918		$ 33,061	$ (1,856)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	16,699	MWh	@	0.027059	$ 452	0.031312	$ 523	$ 71
21	Mid-peak kWh	22,367	MWh	@	0.025831	578	0.027879	624	46
22	Low-peak kWh	51,905	MWh	@	0.020746	1,077	0.022468	1,166	89
23	Off-peak kWh	84,694	MWh	@	0.014013	1,187	0.016805	1,423	236
	Winter (Oct. - May)								
24	High-peak kWh	32,702	MWh	@	0.017361	568	0.020172	660	92
25	Mid-peak kWh	44,338	MWh	@	0.017353	769	0.018676	828	59
26	Off-peak kWh	243,938	MWh	@	0.014935	3,643	0.015536	3,790	147
27	Total Transmission					$ 8,274		$ 9,013	$ 740
	Delivery								
28	System Access	963	Bills	@	200.00	$ 193	200.00	$ 193	$ -
29	Maximum kW	1,431	MW	@	3.50	5,004	3.61	5,168	164
30	Substation Ownership	235	MW	@	(0.83)	(195)	(1.93)	(453)	(258)
31	Distribution	496,642	MWh	@	-	-	-	-	-
32	Power Factor Adjustment					(2)		(2)	0
	Provisions								
33	Education GEI	18,544	MWh	@	(0.000194)	(4)	(0.000205)	(4)	(0)
34	Total Delivery					$ 4,995		$ 4,902	$ (94)
35	Total Full Service					$ 48,187		$ 46,976	$ (1,210)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 3 (GPTU VL 3)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
Page: 20 of 31
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	127,203	MWh	@	0.097734	$ 12,432	0.063232	$ 8,043	$ (4,389)
2	Mid-peak kWh	168,181	MWh	@	0.084321	14,181	0.056274	9,464	(4,717)
3	Low-peak kWh	375,163	MWh	@	0.066009	24,764	0.045488	17,065	(7,699)
4	Off-peak kWh	562,171	MWh	@	0.051593	29,004	0.033901	19,058	(9,946)
	Capacity								
5	High-peak kWh	127,203	MWh	@	0.007268	924	0.036350	4,624	3,699
6	Mid-peak kWh	168,181	MWh	@	0.006938	1,167	0.032364	5,443	4,276
7	Low-peak kWh	375,163	MWh	@	0.005572	2,090	0.026083	9,785	7,695
8	Off-peak kWh	562,171	MWh	@	0.003764	2,116	0.019509	10,967	8,851
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	216,061	MWh	@	0.064408	13,916	0.040715	8,797	(5,119)
10	Mid-peak kWh	295,549	MWh	@	0.059644	17,628	0.037747	11,156	(6,472)
11	Off-peak kWh	1,567,912	MWh	@	0.050334	78,920	0.031690	49,687	(29,233)
	Capacity								
12	High-peak kWh	216,061	MWh	@	0.004663	1,007	0.023417	5,060	4,052
13	Mid-peak kWh	295,549	MWh	@	0.004661	1,378	0.021680	6,408	5,030
14	Off-peak kWh	1,567,912	MWh	@	0.004011	6,290	0.018036	28,279	21,990
15	Power Factor Adjustment					484		456	(28)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	3,312,240	MWh	@	0.009410	31,168	0.009410	31,168	-
19	Total Production					$ 237,469		$ 225,460	$ (12,009)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	127,203	MWh	@	0.027438	$ 3,490	0.031809	$ 4,046	$ 556
21	Mid-peak kWh	168,181	MWh	@	0.026193	4,405	0.028321	4,763	358
22	Low-peak kWh	375,163	MWh	@	0.021036	7,892	0.022824	8,563	671
23	Off-peak kWh	562,171	MWh	@	0.014209	7,988	0.017071	9,597	1,609
	Winter (Oct. - May)								
24	High-peak kWh	216,061	MWh	@	0.017604	3,803	0.020492	4,427	624
25	Mid-peak kWh	295,549	MWh	@	0.017596	5,200	0.018972	5,607	407
26	Off-peak kWh	1,567,912	MWh	@	0.015144	23,745	0.015783	24,746	1,002
27	Total Transmission					$ 56,524		$ 61,750	$ 5,226
	Delivery								
28	System Access	16,957	Bills	@	200.00	$ 3,391	200.00	$ 3,391	$ -
29	Maximum kW	10,275	MW	@	7.02	72,181	6.68	68,656	(3,524)
30	Distribution	3,312,240	MWh	@	-	-	-	-	-
31	Power Factor Adjustment					170		161	(8)
	Provisions								
32	Education GEI	278,712	MWh	@	(0.000194)	(54)	(0.000205)	(57)	(3)
33	Total Delivery					$ 75,688		$ 72,152	$ (3,536)
34	Total Full Service					$ 369,681		$ 359,362	$ (10,319)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 1 (EIP VL 1)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
Page: 21 of 31
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	206	MWh	@	0.138468	$ 29	0.099498	$ 21	$ (8)
2	High-peak kWh	7,015	MWh	@	0.092312	648	0.066332	465	(182)
3	Mid-peak kWh	7,214	MWh	@	0.079643	575	0.059487	429	(145)
4	Low-peak kWh	45,458	MWh	@	0.062347	2,834	0.047278	2,149	(685)
5	Off-peak kWh	61,205	MWh	@	0.048731	2,983	0.034619	2,119	(864)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	206	MWh	@	0.008141	2	0.040218	8	7
8	High-peak kWh	7,015	MWh	@	0.005427	38	0.026812	188	150
9	Mid-peak kWh	7,214	MWh	@	0.005305	38	0.023872	172	134
10	Low-peak kWh	45,458	MWh	@	0.004363	198	0.019239	875	676
11	Off-peak kWh	61,205	MWh	@	0.002792	171	0.014390	881	710
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	647	MWh	@	0.091252	59	0.062127	40	(19)
13	High-peak kWh	14,105	MWh	@	0.060834	858	0.041418	584	(274)
14	Mid-peak kWh	14,704	MWh	@	0.056336	828	0.038779	570	(258)
15	Off-peak kWh	182,038	MWh	@	0.047542	8,654	0.032609	5,936	(2,718)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	647	MWh	@	0.005270	3	0.025909	17	13
18	High-peak kWh	14,105	MWh	@	0.003513	50	0.017272	244	194
19	Mid-peak kWh	14,704	MWh	@	0.003466	51	0.015992	235	184
20	Off-peak kWh	182,038	MWh	@	0.003037	553	0.013303	2,422	1,869
21	Power Factor Adjustment					7		7	(0)
22	Interruptible Credit	332,592	MWh	@	(0.008476)	(2,819)	(0.008461)	(2,814)	5
23	Annual PSCR Factor	332,592	MWh	@	0.009410	3,130	0.009410	3,130	-
24	Total Production					$ 18,889		$ 17,677	$ (1,212)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	206	MWh	@	0.034940	$ 7	0.041546	$ 9	$ 1
26	High-peak kWh	7,015	MWh	@	0.023293	163	0.027698	194	31
27	Mid-peak kWh	7,214	MWh	@	0.022769	164	0.024660	178	14
28	Low-peak kWh	45,458	MWh	@	0.018726	851	0.019874	903	52
29	Off-peak kWh	61,205	MWh	@	0.011984	733	0.014865	910	176
	Winter (Oct. - May)								
30	Critical-peak kWh	647	MWh	@	0.022619	15	0.026765	17	3
31	High-peak kWh	14,105	MWh	@	0.015079	213	0.017843	252	39
32	Mid-peak kWh	14,704	MWh	@	0.014877	219	0.016520	243	24
33	Off-peak kWh	182,038	MWh	@	0.013037	2,373	0.013743	2,502	129
34	Total Transmission					$ 4,739		$ 5,208	$ 469
	Delivery								
35	System Access	64	Bills	@	200.00	$ 13	200.00	$ 13	$ -
36	Maximum kW	771	MW	@	1.02	785	2.37	1,830	1,045
37	Substation Ownership	-	MW	@	(0.66)	-	(1.82)	-	-
38	Power Factor Adjustment					0		1	0
39	Distribution	332,592	MWh	@	-	-	-	-	-
40	Total Delivery					$ 798		$ 1,843	$ 1,045
41	Total Full Service					$ 24,426		$ 24,728	$ 302

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 2 (EIP VL 2)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	27	MWh	@	0.140130	$ 4	0.100662	$ 3	$ (1)
2	High-peak kWh	895	MWh	@	0.093420	84	0.067108	60	(24)
3	Mid-peak kWh	937	MWh	@	0.080599	76	0.060183	56	(19)
4	Low-peak kWh	7,371	MWh	@	0.063095	465	0.047832	353	(113)
5	Off-peak kWh	10,461	MWh	@	0.049316	516	0.035024	366	(150)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	27	MWh	@	0.008261	0	0.040805	1	1
8	High-peak kWh	895	MWh	@	0.005507	5	0.027203	24	19
9	Mid-peak kWh	937	MWh	@	0.005383	5	0.024220	23	18
10	Low-peak kWh	7,371	MWh	@	0.004427	33	0.019519	144	111
11	Off-peak kWh	10,461	MWh	@	0.002833	30	0.014600	153	123
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	79	MWh	@	0.092347	7	0.062854	5	(2)
13	High-peak kWh	1,503	MWh	@	0.061565	93	0.041903	63	(30)
14	Mid-peak kWh	1,737	MWh	@	0.057012	99	0.039232	68	(31)
15	Off-peak kWh	30,227	MWh	@	0.048112	1,454	0.032990	997	(457)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	79	MWh	@	0.005348	0	0.026287	2	2
18	High-peak kWh	1,503	MWh	@	0.003565	5	0.017525	26	21
19	Mid-peak kWh	1,737	MWh	@	0.003517	6	0.016225	28	22
20	Off-peak kWh	30,227	MWh	@	0.003082	93	0.013498	408	315
21	Power Factor Adjustment					(15)		(14)	1
22	Interruptible Credit	53,237	MWh	@	(0.008476)	(451)	(0.008461)	(450)	1
23	Annual PSCR Factor	53,237	MWh	@	0.009410	501	0.009410	501	-
24	Total Production					$ 3,009		$ 2,817	$ (192)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	27	MWh	@	0.035454	$ 1	0.042153	$ 1	$ 0
26	High-peak kWh	895	MWh	@	0.023636	21	0.028102	25	4
27	Mid-peak kWh	937	MWh	@	0.023103	22	0.025021	23	2
28	Low-peak kWh	7,371	MWh	@	0.019002	140	0.020164	149	9
29	Off-peak kWh	10,461	MWh	@	0.012160	127	0.015082	158	31
	Winter (Oct. - May)								
30	Critical-peak kWh	79	MWh	@	0.022952	2	0.027155	2	0
31	High-peak kWh	1,503	MWh	@	0.015301	23	0.018104	27	4
32	Mid-peak kWh	1,737	MWh	@	0.015095	26	0.016761	29	3
33	Off-peak kWh	30,227	MWh	@	0.013228	400	0.013944	421	22
34	Total Transmission					$ 762		$ 836	$ 74
	Delivery								
35	System Access	82	Bills	@	200.00	$ 16	200.00	$ 16	$ -
36	Maximum kW	373	MW	@	3.50	1,304	3.61	1,347	43
37	Substation Ownership	169	MW	@	(0.83)	(141)	(1.93)	(326)	(186)
38	Power Factor Adjustment					(6)		(5)	1
39	Distribution	53,237	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,174		$ 1,032	$ (142)
41	Total Full Service					$ 4,945		$ 4,685	$ (260)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 3 (EIP VL 3)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	1	MWh	@	0.141514	$ 0	0.101677	$ 0	$ (0)
2	High-peak kWh	66	MWh	@	0.094343	6	0.067784	5	(2)
3	Mid-peak kWh	104	MWh	@	0.081395	8	0.060790	6	(2)
4	Low-peak kWh	1,569	MWh	@	0.063719	100	0.048314	76	(24)
5	Off-peak kWh	908	MWh	@	0.049803	45	0.035378	32	(13)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	1	MWh	@	0.008376	0	0.041452	0	0
8	High-peak kWh	66	MWh	@	0.005584	0	0.027635	2	1
9	Mid-peak kWh	104	MWh	@	0.005458	1	0.024605	3	2
10	Low-peak kWh	1,569	MWh	@	0.004489	7	0.019829	31	24
11	Off-peak kWh	908	MWh	@	0.002873	3	0.014831	13	11
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	4	MWh	@	0.093259	0	0.063488	0	(0)
13	High-peak kWh	93	MWh	@	0.062173	6	0.042325	4	(2)
14	Mid-peak kWh	119	MWh	@	0.057575	7	0.039628	5	(2)
15	Off-peak kWh	3,871	MWh	@	0.048588	188	0.033323	129	(59)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	4	MWh	@	0.005422	0	0.026704	0	0
18	High-peak kWh	93	MWh	@	0.003615	0	0.017803	2	1
19	Mid-peak kWh	119	MWh	@	0.003566	0	0.016483	2	2
20	Off-peak kWh	3,871	MWh	@	0.003125	12	0.013712	53	41
21	Power Factor Adjustment					(1)		(1)	0
22	Interruptible Credit	6,737	MWh	@	(0.008476)	(57)	(0.008461)	(57)	0
23	Annual PSCR Factor	6,737	MWh	@	0.009410	63	0.009410	63	-
24	Total Production					$ 390		$ 368	$ (22)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	1	MWh	@	0.035950	$ 0	0.042822	$ 0	$ 0
26	High-peak kWh	66	MWh	@	0.023967	2	0.028548	2	0
27	Mid-peak kWh	104	MWh	@	0.023427	2	0.025418	3	0
28	Low-peak kWh	1,569	MWh	@	0.019268	30	0.020484	32	2
29	Off-peak kWh	908	MWh	@	0.012330	11	0.015321	14	3
	Winter (Oct. - May)								
30	Critical-peak kWh	4	MWh	@	0.023273	0	0.027586	0	0
31	High-peak kWh	93	MWh	@	0.015515	1	0.018391	2	0
32	Mid-peak kWh	119	MWh	@	0.015307	2	0.017027	2	0
33	Off-peak kWh	3,871	MWh	@	0.013413	52	0.014165	55	3
34	Total Transmission					$ 101		$ 109	$ 9
	Delivery								
35	System Access	54	Bills	@	200.00	$ 11	200.00	$ 11	$ -
36	Maximum kW	40	MW	@	7.02	280	6.68	267	(14)
37	Power Factor Adjustment					(1)		(1)	0
38	Distribution	6,737	MWh	@	-	-	-	-	-
39	Total Delivery					$ 290		$ 277	$ (14)
40	Total Full Service					$ 782		$ 754	$ (27)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Metered Lighting (GML)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c) Present Rate $/unit	(d) Present Revenue $000	(e) Proposed Rate $/unit	(f) Proposed Revenue $000	(g) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
1	Secondary All kWh	10,328	MWh	@	0.040925	$ 423	0.034716	$ 359	$ (64)
2	Primary All kWh	448	MWh	@	0.020084	9	0.017037	8	(1)
3	Annual PSCR Factor	10,776	MWh	@	0.009410	101	0.009410	101	-
4	Total Production					$ 533		$ 468	$ (65)
	Transmission								
5	Secondary All kWh	10,328	MWh	@	0.010058	104	0.010556	109	5
6	Primary All kWh	448	MWh	@	0.004936	2	0.005180	2	0
7	Total Transmission	10,776				106		111	5
	Delivery								
	Secondary								
8	System Access	4,489	Bills	@	10.00	$ 45	10.00	$ 45	$ -
9	Distribution	10,328	MWh	@	0.087373	902	0.118564	1,225	322
	Primary								
10	System Access	297	Bills	@	20.00	$ 6	20.00	$ 6	$ -
11	Distribution	448	MWh	@	0.066586	30	0.090355	41	11
12	Total Delivery					$ 983		$ 1,316	$ 333
13	Total Full Service					$ 1,622		$ 1,895	$ 273

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Universal Unmetered Light (UUL)

Case No.: U-22070
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Witness: LMConnolly
Date: June 2026

Line		Billing Determinants							Present					Proposed					
						Customer	Company		Customer Owned		Company Owned			Customer Owned		Company Owned			Net Increase
No.	Description	Customer	Company	Units	Watts	MWh	MWh		Production	Delivery	Production	Delivery	Revenue	Production	Delivery	Production	Delivery	Revenue	/ (Decrease)
									$/Light	$/Light	$/Light	$/Light	$000	$/Light	$/Light	$/Light	$/Light	$000	$000
1	15 - 24 Watts	12	-	Lights	20	0	-	@	0.33	6.67	0.33	9.67	$ 0	0.28	7.29	0.28	10.29	$ 0	$ 0
2	25 - 34 Watts	-	64,500	Lights	30	-	666	@	0.49	7.19	0.49	10.19	689	0.43	8.07	0.43	11.07	742	53
3	35 - 44 Watts	1,524	412,356	Lights	40	21	5,701	@	0.66	7.71	0.66	10.71	4,701	0.57	8.85	0.57	11.85	5,136	435
4	45 - 54 Watts	1,308	865,773	Lights	50	23	15,000	@	0.83	8.23	0.83	11.23	10,453	0.72	9.63	0.72	12.63	11,572	1,119
5	55 - 64 Watts	1,092	7,056	Lights	60	23	147	@	1.00	8.75	1.00	11.75	101	0.86	10.41	0.86	13.41	113	12
6	65 - 74 Watts	312	129,516	Lights	70	8	3,150	@	1.16	9.27	1.16	12.27	1,743	1.01	11.19	1.01	14.19	1,972	230
7	75 - 84 Watts	72	34,020	Lights	80	2	947	@	1.33	9.79	1.33	12.79	481	1.15	11.97	1.15	14.97	549	68
8	85 - 94 Watts	-	98,178	Lights	90	-	3,075	@	1.50	10.31	1.50	13.31	1,454	1.29	12.75	1.29	15.75	1,673	219
9	95 - 104 Watts	-	180	Lights	100	-	6	@	1.66	10.83	1.66	13.83	3	1.44	13.53	1.44	16.53	3	0
10	105 - 114 Watts	-	7,044	Lights	110	-	270	@	1.83	11.35	1.83	14.35	114	1.58	14.31	1.58	17.31	133	19
11	115 - 124 Watts	804	364,751	Lights	120	34	15,256	@	2.00	11.87	2.00	14.87	6,164	1.73	15.09	1.73	18.09	7,243	1,078
12	125 - 134 Watts	-	320	Lights	130	-	15	@	2.17	12.38	2.17	15.38	6	1.87	15.86	1.87	18.86	7	1
13	135 - 144 Watts	-	924	Lights	140	-	45	@	2.33	12.90	2.33	15.90	17	2.02	16.64	2.02	19.64	20	3
14	145 - 154 Watts	-	3,996	Lights	150	-	209	@	2.50	13.42	2.50	16.42	76	2.16	17.42	2.16	20.42	90	15
15	155 - 164 Watts	-	52	Lights	160	-	3	@	2.67	13.94	2.67	16.94	1	2.31	18.20	2.31	21.20	1	0
16	165 - 174 Watts	1,404	51,182	Lights	170	83	3,036	@	2.83	14.46	2.83	17.46	1,063	2.45	18.98	2.45	21.98	1,280	218
17	175 - 184 Watts	-	-	Lights	180	-	-	@	3.00	14.98	3.00	17.98	-	2.60	19.76	2.60	22.76	-	-
18	185 - 194 Watts	-	156	Lights	190	-	10	@	3.17	15.50	3.17	18.50	3	2.74	20.54	2.74	23.54	4	1
19	195 - 204 Watts	-	60	Lights	200	-	4	@	3.34	16.02	3.34	19.02	1	2.89	21.32	2.89	24.32	2	0
20	205 - 214 Watts	504	12,740	Lights	210	37	934	@	3.50	16.54	3.50	19.54	304	3.03	22.10	3.03	25.10	371	67
21	215 - 224 Watts	-	28	Lights	220	-	2	@	3.67	17.06	3.67	20.06	1	3.17	22.88	3.17	25.88	1	0
22	225 - 234 Watts	-	-	Lights	230	-	-	@	3.84	17.58	3.84	20.58	-	3.32	23.66	3.32	26.66	-	-
23	235 - 244 Watts	-	-	Lights	240	-	-	@	4.01	18.10	4.01	21.10	-	3.46	24.44	3.46	27.44	-	-
24	245 - 254 Watts	60	432	Lights	250	5	38	@	4.17	18.62	4.17	21.62	13	3.61	25.22	3.61	28.22	15	3
25	255 - 264 Watts	-	-	Lights	260	-	-	@	4.34	19.13	4.34	22.13	-	3.75	26.00	3.75	29.00	-	-
26	265 - 274 Watts	-	-	Lights	270	-	-	@	4.51	19.65	4.51	22.65	-	3.90	26.78	3.90	29.78	-	-
27	275 - 284 Watts	396	3,949	Lights	280	39	386	@	4.67	20.17	4.67	23.17	120	4.04	27.56	4.04	30.56	149	29
28	285 - 294 Watts	12	1,292	Lights	290	1	131	@	4.84	20.69	4.84	23.69	37	4.19	28.34	4.19	31.34	46	9
29	295 - 304 Watts	-	-	Lights	300	-	-	@	5.01	21.21	5.01	24.21	-	4.33	29.12	4.33	32.12	-	-
30	305 - 314 Watts	108	-	Lights	310	12	-	@	5.18	21.73	5.18	24.73	3	4.48	29.90	4.48	32.90	4	1
31	315 - 324 Watts	540	29,081	Lights	320	60	3,252	@	5.34	22.25	5.34	25.25	904	4.62	30.68	4.62	33.68	1,133	228
32	325 - 334 Watts	-	-	Lights	330	-	-	@	5.51	22.77	5.51	25.77	-	4.77	31.45	4.77	34.45	-	-
33	335 - 344 Watts	-	-	Lights	340	-	-	@	5.68	23.29	5.68	26.29	-	4.91	32.23	4.91	35.23	-	-
34	345 - 354 Watts	-	-	Lights	350	-	-	@	5.84	23.81	5.84	26.81	-	5.05	33.01	5.05	36.01	-	-
35	355 - 364 Watts	-	-	Lights	360	-	-	@	6.01	24.33	6.01	27.33	-	5.20	33.79	5.20	36.79	-	-
36	365 - 374 Watts	-	-	Lights	370	-	-	@	6.18	24.85	6.18	27.85	-	5.34	34.57	5.34	37.57	-	-
37	375 - 384 Watts	-	-	Lights	380	-	-	@	6.35	25.37	6.35	28.37	-	5.49	35.35	5.49	38.35	-	-
38	385 - 394 Watts	-	-	Lights	390	-	-	@	6.51	25.89	6.51	28.89	-	5.63	36.13	5.63	39.13	-	-
39	395 - 404 Watts	-	12	Lights	400	-	2	@	6.68	26.40	6.68	29.40	0	5.78	36.91	5.78	39.91	1	0
40	405 - 414 Watts	24	24	Lights	410	3	3	@	6.85	26.92	6.85	29.92	2	5.92	37.69	5.92	40.69	2	0
41	415 - 424 Watts	-	-	Lights	420	-	-	@	7.02	27.44	7.02	30.44	-	6.07	38.47	6.07	41.47	-	-
42	425 - 434 Watts	-	-	Lights	430	-	-	@	7.18	27.96	7.18	30.96	-	6.21	39.25	6.21	42.25	-	-
43	435 - 444 Watts	-	-	Lights	440	-	-	@	7.35	28.48	7.35	31.48	-	6.36	40.03	6.36	43.03	-	-
44	445 - 454 Watts	-	-	Lights	450	-	-	@	7.52	29.00	7.52	32.00	-	6.50	40.81	6.50	43.81	-	-
45	455 - 464 Watts	888	1,460	Lights	460	143	235	@	7.68	29.52	7.68	32.52	92	6.65	41.59	6.65	44.59	118	26
46	465 - 474 Watts	-	-	Lights	470	-	-	@	7.85	30.04	7.85	33.04	-	6.79	42.37	6.79	45.37	-	-
47	475 - 484 Watts	180	9,489	Lights	480	30	1,593	@	8.02	30.56	8.02	33.56	402	6.94	43.15	6.94	46.15	513	111
48	Conversion Credit	-	129,840	Lights								(6.91)	(897)				(7.72)	(1,002)	(105)
49	Annual PSCR Factor	9,240	2,098,571	Lights		524	54,116		0.009410		0.009410		514	0.009410		0.009410		514	-
50	Total Unmetered LED	9,240	2,098,571	Lights		524	54,116						$ 28,563					$ 32,405	$ 3,842

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Unmetered Service (GU)

Case No.: U-22070
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Witness: LMConnolly
Date: June 2026

	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
Line		Billing Determinants			Present		Proposed		Net Increase
No.	Description	Quantity	Units		Rate	Revenue	Rate	Revenue	/ (Decrease)
					$/unit	$000	$/unit	$000	$000
	FULL SERVICE								
	Production								
1	Non-capacity All kWh	99,352	MWh	@	0.054054	$ 5,370	0.037706	$ 3,746	$ (1,624)
2	Capacity All kWh	99,352	MWh	@	0.003187	317	0.015927	1,582	1,266
3	Annual PSCR Factor	99,352	MWh	@	0.009410	935	0.009410	935	-
4	Total Production					$ 6,622		$ 6,264	$ (358)
	Transmission								
5	All kWh	99,352	MWh	@	0.013872	1,378	0.015085	1,499	120
	Delivery								
6	System Access	5,578	Bills	@	2.00	$ 11	2.00	$ 11	$ -
7	Distribution	99,352	MWh	@	0.028437	2,825	0.034452	3,423	598
8	Total Delivery					$ 2,836		$ 3,434	$ 598
9	Total Full Service					$ 10,837		$ 11,196	$ 360

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Large Self-generation (GSG-2)

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	STANDBY SERVICE								
	Production								
	Voltage Level 1								
1	On-peak kW-day	108	MW	@	11.57	$ 1,254	11.57	$ 1,254	$ -
2	All kWh	77,349	MWh	@	0.046132	3,568	0.046132	3,568	-
	Voltage Level 2								
3	On-peak kW-day	223	MW	@	11.73	2,613	11.73	2,613	-
4	All kWh	77,337	MWh	@	0.048126	3,722	0.048126	3,722	-
	Voltage Level 3								
5	On-peak kW-day	55	MW	@	11.91	650	11.91	650	-
6	All kWh	18,615	MWh	@	0.047120	877	0.047120	877	-
7	Power Factor Adjustment					261		261	-
8	Total Production					$ 12,946		$ 12,946	$ -
	Transmission								
	Voltage Level 1								
9	On-peak kW-day	108	MW	@	3.05	$ 330	3.05	$ 330	$ -
	Voltage Level 2								
10	On-peak kW-day	223	MW	@	3.09	688	3.09	688	-
	Voltage Level 3								
11	On-peak kW-day	55	MW	@	3.14	171	3.14	171	-
12	Total Transmission					$ 1,190		$ 1,190	$ -
	Delivery								
	System Access								
	Voltage Level 1								
13	Standby	64	Bills	@	100.00	$ 6	100.00	$ 6	$ -
14	Supplemental	-	Bills	@	100.00	-	100.00	-	-
15	Maximum kW	889	MW	@	1.02	905	2.37	2,110	1,205
16	Interconnect	355	MW	@	(1.02)	(361)	(2.37)	(842)	(481)
17	Substation Ownership	-	MW	@	(0.66)	-	(1.82)	-	-
	Voltage Level 2								
18	Standby	94	Bills	@	100.00	$ 9	100.00	$ 9	$ -
19	Supplemental	-	Bills	@	100.00	-	100.00	-	-
20	Maximum kW	610	MW	@	3.50	2,133	3.61	2,203	70
21	Substation Ownership	288	MW	@	(0.83)	(239)	(1.93)	(555)	(316)
	Voltage Level 3								
22	Standby	13	Bills	@	100.00	$ 1	100.00	$ 1	$ -
23	Supplemental	-	Bills	@	100.00	-	100.00	-	-
24	Maximum kW	62	MW	@	7.02	433	6.68	412	(21)
25	Power Factor Adjustment					58		63	5
26	Total Delivery					$ 2,946		$ 3,408	$ 462
27	Total Standby Service					$ 17,081		$ 17,543	$ 462

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response (DR) Surcharge

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	ID	(b) Program plus Cust. Credits (1)	(c) Financial Incentive (1)	(d) Reconciled Balance (1)	(e) Total	(f) Units
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	DR0001	0.002006	-	-	0.002006	per kWh
2	Smart Hours RSH	DR0001	0.002006	-	-	0.002006	per kWh
3	Night Time Savers RPM	DR0001	0.002006	-	-	0.002006	per kWh
4	Non-Transmitting Meters RSM	DR0001	0.002006	-	-	0.002006	per kWh
	Secondary Class						
5	Energy-only GS	DR0002	0.001796	-	-	0.001796	per kWh
6	Time-of-Use GSTU	DR0003	0.001796	-	-	0.001796	per kWh
7	Demand GSD	DR0004	0.60	-	-	0.60	per Peak kW
	Primary Class						
	Energy-only GP						
8	Voltage Level 1	DR0005	0.001532	-	-	0.001532	per kWh
9	Voltage Level 2	DR0006	0.001550	-	-	0.001550	per kWh
10	Voltage Level 3	DR0007	0.001566	-	-	0.001566	per kWh
	Demand GPD						
11	Voltage Level 1	DR0008	0.67	-	-	0.67	per On-Peak kW
12	Voltage Level 2	DR0009	0.68	-	-	0.68	per On-Peak kW
13	Voltage Level 3	DR0010	0.69	-	-	0.69	per On-Peak kW
	Time-of-Use GPTU						
14	Voltage Level 1	DR0011	0.001363	-	-	0.001363	per kWh
15	Voltage Level 2	DR0012	0.001379	-	-	0.001379	per kWh
16	Voltage Level 3	DR0013	0.001393	-	-	0.001393	per kWh
	Energy Intensive EIP						
17	Voltage Level 1	DR0014	0.001142	-	-	0.001142	per kWh
18	Voltage Level 2	DR0015	0.001156	-	-	0.001156	per kWh
19	Voltage Level 3	DR0016	0.001167	-	-	0.001167	per kWh
	Lighting & Unmetered Class						
20	Metered Lighting GML	DR0017	0.000467	-	-	0.000467	per kWh
21	Universal Unmetered Lighting UUL	DR0018	0.000439	-	-	0.000439	per kWh
22	Unmetered GU	DR0019	0.001185	-	-	0.001185	per kWh
	ROA SERVICE						
	Secondary Class						
23	Energy-only GS		NA	NA	NA	NA	
24	Demand GSD		NA	NA	NA	NA	
	Primary Class						
	Energy-only GP						
25	Voltage Level 1		NA	NA	NA	NA	
26	Voltage Level 2		NA	NA	NA	NA	
27	Voltage Level 3		NA	NA	NA	NA	
	Demand GPD						
28	Voltage Level 1		NA	NA	NA	NA	
29	Voltage Level 2		NA	NA	NA	NA	
30	Voltage Level 3		NA	NA	NA	NA	

(1) WP-LMC-19

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Rate Case (ERC) Deferral Surcharge

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
Page: 29 of 31
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) ERC Deferral [1] ($000)	(d) ERC Deferral Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 15,489	0.001221
	Secondary Class			
2	Energy-only GS	4,114,839	3,839	0.000933
3	Time-of-Use GSTU	84,563	79	0.000933
4	Demand GSD	2,979,606	2,145	0.000720
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	0	0.000116
6	Voltage Level 2	31,259	6	0.000178
7	Voltage Level 3	632,239	193	0.000305
	Demand GPD			
8	Voltage Level 1	1,167,540	91	0.000078
9	Voltage Level 2	1,453,040	174	0.000120
10	Voltage Level 3	2,414,780	495	0.000205
	Time-of-Use GPTU			
11	Voltage Level 1	464,518	36	0.000078
12	Voltage Level 2	496,642	60	0.000120
13	Voltage Level 3	3,312,240	679	0.000205
	Energy Intensive EIP			
14	Voltage Level 1	332,592	26	0.000078
15	Voltage Level 2	53,237	6	0.000120
16	Voltage Level 3	6,737	1	0.000205
	Lighting & Unmetered Class			
17	Metered Lighting GML	10,776	15	0.001409
18	Universal Unmetered Lighting UUL	54,640	342	0.006253
19	Unmetered GU	99,352	40	0.000402
	Self-generation Class			
20	Large Self-generation GSG-2			
21	Voltage Level 1	77,349	6	0.000078
22	Voltage Level 2	77,337	9	0.000120
23	Voltage Level 3	18,615	4	0.000205
24	Total Full Service		$ 23,736	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) ERC Deferral [1] ($000)	(h) ERC Deferral Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001221
	Secondary Class			
2	Energy-only GS	18,702	17	0.000933
3	Time-of-Use GSTU	-	-	0.000933
4	Demand GSD	174,288	125	0.000720
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000116
6	Voltage Level 2	1,783	0	0.000178
7	Voltage Level 3	70,285	21	0.000305
	Demand GPD			
8	Voltage Level 1	1,270,576	99	0.000078
9	Voltage Level 2	1,080,207	130	0.000120
10	Voltage Level 3	953,091	195	0.000205
11	Total ROA Service		$ 589	
12	Total Surcharge Revenue Collected		$ 24,325	
13	Rounding		3	
14	Total Surcharge Revenue Target		$ 24,327	

(1) A-89 (EAD-5), line 12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 1 - 12 months ending April 30, 2027

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
Page: 30 of 31
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue (1) ($000)	(d) IRM Surcharge ($ / kWh)	Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue (1) ($000)	(h) IRM Surcharge ($ / kWh)
	FULL SERVICE					**ROA SERVICE**			
1	Residential Class	12,685,410	$ 8,867	0.000699	1	Residential Class	-	$ -	0.000699
	Secondary Class					Secondary Class			
2	Energy-only GS	4,114,839	2,197	0.000534	2	Energy-only GS	18,702	10	0.000534
3	Time-of-Use GSTU	84,563	45	0.000534	3	Time-of-Use GSTU	-	-	0.000534
4	Demand GSD	2,979,606	1,228	0.000412	4	Demand GSD	174,288	72	0.000412
	Primary Class					Primary Class			
	Energy-only GP					Energy-only GP			
5	Voltage Level 1	3,454	0	0.000066	5	Voltage Level 1	-	-	0.000066
6	Voltage Level 2	31,259	3	0.000101	6	Voltage Level 2	1,783	0	0.000101
7	Voltage Level 3	632,239	109	0.000173	7	Voltage Level 3	70,285	12	0.000173
	Demand GPD					Demand GPD			
8	Voltage Level 1	1,167,540	53	0.000045	8	Voltage Level 1	1,270,576	57	0.000045
9	Voltage Level 2	1,453,040	100	0.000069	9	Voltage Level 2	1,080,207	75	0.000069
10	Voltage Level 3	2,414,780	285	0.000118	10	Voltage Level 3	953,091	112	0.000118
	Time-of-Use GPTU								
11	Voltage Level 1	464,518	21	0.000045	11	Total ROA Service		$ 338	
12	Voltage Level 2	496,642	34	0.000069					
13	Voltage Level 3	3,312,240	391	0.000118	12	Total Surcharge Revenue Collected		$ 13,930	
	Energy Intensive EIP				13	Rounding		(3)	
14	Voltage Level 1	332,592	15	0.000045	14	Total Surcharge Revenue Target		$ 13,927	
15	Voltage Level 2	53,237	4	0.000069					
16	Voltage Level 3	6,737	1	0.000118					
	Lighting & Unmetered Class								
17	Metered Lighting GML	10,776	9	0.000806					
18	Universal Unmetered Lighting UUL	54,640	196	0.003580					
19	Unmetered GU	99,352	23	0.000230					
	Self-generation Class								
20	Large Self-generation GSG-2								
21	Voltage Level 1	77,349	3	0.000045					
22	Voltage Level 2	77,337	5	0.000069					
23	Voltage Level 3	18,615	2	0.000118					
24	Total Full Service		$ 13,591						

(1) A-89 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 2 - 12 months ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-68 (LMC-5)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue (1) ($000)	(d) IRM Surcharge ($ / kWh)	Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue (1) ($000)	(h) IRM Surcharge ($ / kWh)
	FULL SERVICE					**ROA SERVICE**			
1	Residential Class	12,685,410	$ 16,301	0.001285	1	Residential Class	-	$ -	0.001285
	Secondary Class					Secondary Class			
2	Energy-only GS	4,114,839	4,037	0.000981	2	Energy-only GS	18,702	18	0.000981
3	Time-of-Use GSTU	84,563	83	0.000981	3	Time-of-Use GSTU	-	-	0.000981
4	Demand GSD	2,979,606	2,259	0.000758	4	Demand GSD	174,288	132	0.000758
	Primary Class					Primary Class			
	Energy-only GP					Energy-only GP			
5	Voltage Level 1	3,454	0	0.000122	5	Voltage Level 1	-	-	0.000122
6	Voltage Level 2	31,259	10	0.000320	6	Voltage Level 2	1,783	1	0.000320
7	Voltage Level 3	632,239	202	0.000320	7	Voltage Level 3	70,285	22	0.000320
	Demand GPD					Demand GPD			
8	Voltage Level 1	1,167,540	85	0.000073	8	Voltage Level 1	1,270,576	93	0.000073
9	Voltage Level 2	1,453,040	279	0.000192	9	Voltage Level 2	1,080,207	207	0.000192
10	Voltage Level 3	2,414,780	464	0.000192	10	Voltage Level 3	953,091	183	0.000192
	Time-of-Use GPTU								
11	Voltage Level 1	464,518	34	0.000073	11	Total ROA Service		$ 657	
12	Voltage Level 2	496,642	95	0.000192					
13	Voltage Level 3	3,312,240	636	0.000192	12	Total Surcharge Revenue Collected		$ 25,619	
	Energy Intensive EIP				13	Rounding		(22)	
14	Voltage Level 1	332,592	24	0.000073	14	Total Surcharge Revenue Target		$ 25,597	
15	Voltage Level 2	53,237	10	0.000192					
16	Voltage Level 3	6,737	1	0.000192					
	Lighting & Unmetered Class								
17	Metered Lighting GML	10,776	16	0.001482					
18	Universal Unmetered Lighting UUL	54,640	360	0.006580					
19	Unmetered GU	99,352	42	0.000423					
	Self-generation Class								
20	Large Self-generation GSG-2								
21	Voltage Level 1	77,349	6	0.000073					
22	Voltage Level 2	77,337	15	0.000192					
23	Voltage Level 3	18,615	4	0.000192					
24	Total Full Service		$ 24,962						

(1) A-89 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Total Revenues

Proposal 5

U-21870 Final Order Model

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Customers	(c) Sales	(d) Revenue Present	(e) Revenue Proposed	(f) Net Increase / (Decrease) Revenue	(g) Net Increase / (Decrease) Percent
		Mthly	MWh	$000	$000	$000	%
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	1,628,594	12,230,766	$ 2,530,673	$ 2,552,926	$ 22,253	0.9
2	Smart Hours RSH	24,351	177,999	36,984	37,308	324	0.9
3	Night Time Savers RPM	16,879	168,382	34,132	34,440	308	0.9
4	Non-Transmitting Meters RSM	10,973	108,263	23,269	23,467	198	0.8
5	Total Residential Class	1,680,798	12,685,410	$ 2,625,059	$ 2,648,141	$ 23,083	0.9
	Secondary Class						
6	Energy-only GS	204,973	4,114,839	$ 742,820	$ 748,374	$ 5,554	0.7
7	Time-of-Use GSTU	1,891	84,563	15,240	15,352	113	0.7
8	Demand GSD	20,152	2,979,606	467,203	470,575	3,372	0.7
9	Total Secondary	227,015	7,179,008	$ 1,225,264	$ 1,234,302	$ 9,038	0.7
	Primary Class						
10	Energy-only GP	1,360	666,952	$ 78,703	$ 79,290	$ 587	0.7
11	Demand GPD	855	5,035,360	455,727	458,914	3,187	0.7
12	Large Load	1	7,884,000	-	100,865	100,865	NA
13	Time-of-Use GPTU	1,517	4,273,401	448,037	450,257	2,221	0.5
14	Energy Intensive EIP	17	392,565	30,168	30,391	223	0.7
15	Total Primary	3,749	18,252,279	$ 1,012,633	$ 1,119,717	$ 107,083	10.6
	Lighting & Unmetered Class						
16	Metered Lighting GML	399	10,776	$ 1,895	$ 1,904	$ 9	0.5
17	Universal Unmetered Lighting UUL	4,696	54,640	32,405	32,598	193	0.6
18	Unmetered GU	465	99,352	11,196	11,261	64	0.6
19	Total Lighting & Unmetered	5,560	164,769	$ 45,496	$ 45,763	$ 267	0.6
	Self-generation Class						
20	Small Self-generation GSG-1	-	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	14	173,301	17,543	17,538	(6)	(0.0)
22	Total Self-generation	14	173,301	$ 17,543	$ 17,538	$ (6)	(0.0)
23	Total Full Service	1,917,136	38,454,766	$ 4,925,995	$ 5,065,460	$ 139,465	2.8
	ROA SERVICE						
	Secondary Class						
24	Energy-only GS	85	18,702	$ 1,307	$ 1,316	$ 9	0.7
25	Demand GSD	472	174,288	10,522	10,585	63	0.6
26	Total Secondary	556	192,989	$ 11,829	$ 11,901	$ 72	0.6
	Primary Class						
27	Energy-only GP	60	72,068	$ 1,792	$ 1,800	$ 9	0.5
28	Demand GPD	356	3,303,873	30,936	31,041	105	0.3
29	Total Primary	417	3,375,942	$ 32,727	$ 32,841	$ 113	0.3
30	Total ROA Service	973	3,568,931	$ 44,557	$ 44,742	$ 186	0.4
31	Total Jurisdictional Service	1,918,109	42,023,697	$ 4,970,552	$ 5,110,203	$ 139,651	2.8
32	Plus: Rounding			-	287	(287)	
33	Total Jurisdictional Revenues			$ 4,970,552	$ 5,110,490	$ 139,938	2.8
34	Less: PSCR Factor Revenues			299,823	374,011	74,188	
35	Less: DR Surcharge			-	51,821	51,821	
36	Less: IRM Surcharge			-	13,927	13,927	
37	Total Jurisdictional Base Revenues			$ 4,670,729	$ 4,670,730	$ 1	0.0
38	Total Jurisdictional Revenues			4,970,552	5,110,490	139,938	2.8
39	Plus: ERC Deferral Surcharge			-	24,289	24,289	
40	Total Jurisdictional Revenues Requested			$ 4,970,552	$ 5,134,779	$ 164,227	3.3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Production & Transmission Revenues

Proposal 5

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Sales	Revenue Present	Revenue Proposed	Net Increase / (Decrease) Revenue	Net Increase / (Decrease) Percent
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,230,766	$ 1,259,128	$ 1,273,454	$ 14,326	1.1
2	Smart Hours RSH	177,999	18,333	18,541	208	1.1
3	Night Time Savers RPM	168,382	17,006	17,205	199	1.2
4	Non-Transmitting Meters RSM	108,263	11,022	11,149	128	1.2
5	Total Residential Class	12,685,410	$ 1,305,488	$ 1,320,350	$ 14,861	1.1
	Secondary Class					
6	Energy-only GS	4,114,839	$ 408,019	$ 411,587	$ 3,568	0.9
7	Time-of-Use GSTU	84,563	8,915	8,986	72	0.8
8	Demand GSD	2,979,606	279,797	282,093	2,296	0.8
9	Total Secondary	7,179,008	$ 696,731	$ 702,667	$ 5,936	0.9
	Primary Class					
10	Energy-only GP	666,952	$ 61,147	$ 61,655	$ 508	0.8
11	Demand GPD	5,035,360	397,720	400,693	2,973	0.7
12	Large Load	7,884,000	-	91,967	91,967	NA
13	Time-of-Use GPTU	4,273,401	367,811	369,831	2,020	0.5
14	Energy Intensive EIP	392,565	27,016	27,238	222	0.8
15	Total Primary	18,252,279	$ 853,693	$ 951,384	$ 97,690	11.4
	Lighting & Unmetered Class					
16	Metered Lighting GML	10,776	$ 579	$ 580	$ 1	0.2
17	Universal Unmetered Lighting UUL	54,640	2,776	2,778	2	0.1
18	Unmetered GU	99,352	7,762	7,808	46	0.6
19	Total Lighting & Unmetered	164,769	$ 11,117	$ 11,166	$ 49	0.4
	Self-generation Class					
20	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	173,301	14,136	14,136	-	-
22	Total Self-generation	173,301	$ 14,136	$ 14,136	$ -	-
23	Total Full Service	38,454,766	$ 2,881,165	$ 2,999,702	$ 118,537	4.1
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	-	$ -	$ -	$ -	NA
25	Demand GSD	-	-	-	-	NA
26	Total Secondary	-	$ -	$ -	$ -	NA
	Primary Class					
27	Energy-only GP	-	$ -	$ -	$ -	NA
28	Demand GPD	-	-	-	-	NA
29	Total Primary	-	$ -	$ -	$ -	NA
30	Total ROA Service	-	$ -	$ -	$ -	NA
31	Total Jurisdictional Service	38,454,766	$ 2,881,165	$ 2,999,702	$ 118,537	4.1
32	Plus: Rounding		-	7,460	7,460	
33	Total Jurisdictional Base Revenues		$ 2,881,165	$ 3,007,162	$ 125,997	4.4
34	Less: PSCR Factor Revenues		299,823	374,011	74,188	
35	Less: DR Surcharge		-	51,821	51,821	
36	Less: IRM Surcharge		-	-	-	
37	Total Jurisdictional Base Revenues		$ 2,581,342	$ 2,581,329	$ (13)	(0.0)
38	Total Jurisdictional Revenues		2,881,165	3,007,162	125,997	4.4
39	Plus: ERC Deferral Surcharge		-	-	-	
40	Total Jurisdictional Revenues Requested		$ 2,881,165	$ 3,007,162	$ 125,997	4.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Delivery Revenues

Proposal 5

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Sales	(c) Revenue Present	(d) Revenue Proposed	(e) Net Increase / (Decrease) Revenue	(f) Net Increase / (Decrease) Percent
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,230,766	$ 1,271,545	$ 1,279,472	$ 7,927	0.6
2	Smart Hours RSH	177,999	18,652	18,767	115	0.6
3	Night Time Savers RPM	168,382	17,126	17,235	109	0.6
4	Non-Transmitting Meters RSM	108,263	12,248	12,318	70	0.6
5	Total Residential Class	12,685,410	$ 1,319,571	$ 1,327,792	$ 8,221	0.6
	Secondary Class					
6	Energy-only GS	4,114,839	$ 334,801	$ 336,787	$ 1,986	0.6
7	Time-of-Use GSTU	84,563	6,325	6,366	41	0.6
8	Demand GSD	2,979,606	187,406	188,482	1,076	0.6
9	Total Secondary	7,179,008	$ 528,533	$ 531,635	$ 3,102	0.6
	Primary Class					
10	Energy-only GP	666,952	$ 17,556	$ 17,635	$ 79	0.5
11	Demand GPD	5,035,360	58,006	58,221	214	0.4
12	Large Load	7,884,000	-	1,437	1,437	NA
13	Time-of-Use GPTU	4,273,401	80,226	80,427	201	0.3
14	Energy Intensive EIP	392,565	3,152	3,153	1	0.0
15	Total Primary	18,252,279	$ 158,940	$ 160,872	$ 1,932	1.2
	Lighting & Unmetered Class					
16	Metered Lighting GML	10,776	$ 1,316	$ 1,324	$ 8	0.6
17	Universal Unmetered Lighting UUL	54,640	29,629	29,820	191	0.6
18	Unmetered GU	99,352	3,434	3,452	18	0.5
19	Total Lighting & Unmetered	164,769	$ 34,379	$ 34,597	$ 218	0.6
	Self-generation Class					
20	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	173,301	3,408	3,402	(6)	(0.2)
22	Total Self-generation	173,301	$ 3,408	$ 3,402	$ (6)	(0.2)
23	Total Full Service	38,454,766	$ 2,044,829	$ 2,058,297	$ 13,468	0.7
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	18,702	$ 1,307	$ 1,316	$ 9	0.7
25	Demand GSD	174,288	10,522	10,585	63	0.6
26	Total Secondary	192,989	$ 11,829	$ 11,901	$ 72	0.6
	Primary Class					
27	Energy-only GP	72,068	$ 1,792	$ 1,800	$ 9	0.5
28	Demand GPD	3,303,873	30,936	31,041	105	0.3
29	Total Primary	3,375,942	$ 32,727	$ 32,841	$ 113	0.3
30	Total ROA Service	3,568,931	$ 44,557	$ 44,742	$ 186	0.4
31	Total Jurisdictional Service	42,023,697	$ 2,089,386	$ 2,103,040	$ 13,654	0.7
32	Plus: Rounding		-	288	288	
33	Total Jurisdictional Base Revenues		$ 2,089,386	$ 2,103,327	$ 13,941	0.7
34	Less: PSCR Factor Revenues		-	-	-	
35	Less: DR Surcharge		-	-	-	
36	Less: IRM Surcharge		-	13,927	13,927	
37	Total Jurisdictional Base Revenues		$ 2,089,386	$ 2,089,400	$ 14	0.0
38	Total Jurisdictional Revenues		2,089,386	2,103,327	13,941	0.7
39	Plus: ERC Deferral Surcharge		-	24,289	24,289	
40	Total Jurisdictional Revenues Requested		$ 2,089,386	$ 2,127,617	$ 38,230	1.8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Rate Design Targets
($000)

Proposal 5

U-21870 Final Order Model

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
Page: 4 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Jurisdictional	(c) Residential	(d) Secondary Class GS	(e) Secondary Class GSD	(f) Primary Class GP	(g) Primary Class GPD	(h) Primary Class LL	(i) Primary Class GPTU	(j) Primary Class EIP	(k) Lighting & Unmetered Class GML	(l) Lighting & Unmetered Class UUL	(m) Lighting & Unmetered Class GU	(n) Self Gen. Class GSG-1	(o) Self Gen. Class GSG-2	Source
	Production															
1	Capacity (SRM)	$ 1,142,215	$ 505,086	$ 148,178	$ 94,160	$ 19,645	$ 110,402	$ 142,750	$ 109,550	$ 7,270	$ 8	$ -	$ 1,931	$ -	$ 3,236	
	Capacity Adjustments [1]															
2	DR Revenue Requirement	(43,454)	(18,153)	(5,465)	(3,563)	(750)	(4,512)	(6,256)	(4,335)	(316)	(3)	(16)	(84)	-	-	WP-LMC-107
3	Self Generation	-	1,278	375	238	50	279	361	277	18	0	-	5	-	(2,883)	Alloc. Line 1
4	Total Adjustments	(43,454)	(16,875)	(5,090)	(3,325)	(700)	(4,232)	(5,895)	(4,058)	(298)	(3)	(16)	(79)	-	(2,883)	
5	Capacity (SRM) Design Target	$ 1,098,761	$ 488,211	$ 143,088	$ 90,835	$ 18,945	$ 106,170	$ 136,855	$ 105,492	$ 6,972	$ 4	$ (16)	$ 1,851	$ -	$ 353	
6	Energy [2]	$ 732,421	$ 400,841	$ 139,733	$ 99,658	$ 22,245	$ 163,578	$ (245,835)	$ 141,698	$ 13,525	$ 363	$ 1,853	$ 3,465	$ -	$ (8,704)	
	Energy Adjustments [1]															
7	Self Generation	-	(4,708)	(1,641)	(1,170)	(261)	(1,921)	2,887	(1,664)	(159)	(4)	(22)	(41)	-	8,704	Alloc. Line 6
8	Total Adjustments	-	(4,708)	(1,641)	(1,170)	(261)	(1,921)	2,887	(1,664)	(159)	(4)	(22)	(41)	-	8,704	
9	Energy Design Target	$ 732,421	$ 396,133	$ 138,092	$ 98,487	$ 21,984	$ 161,656	$ (242,947)	$ 140,034	$ 13,366	$ 359	$ 1,832	$ 3,424	$ -	$ -	
10	Total Production	$ 1,831,181	$ 884,344	$ 281,180	$ 189,322	$ 40,928	$ 267,827	$ (106,092)	$ 245,527	$ 20,339	$ 363	$ 1,816	$ 5,275	$ -	$ 353	
11	**Transmission**															
12	Transmission	758,515	296,007	93,071	60,937	13,514	82,308	123,487	78,677	6,130	111	427	1,493	-	2,353	
13	Self Generation	-	921	290	190	42	256	384	245	19	0	1	5	-	(2,353)	Alloc. Line 12
14	Transmission Design Target	$ 758,515	$ 296,928	$ 93,360	$ 61,127	$ 13,556	$ 82,564	$ 123,871	$ 78,922	$ 6,149	$ 111	$ 428	$ 1,498	$ -	$ -	
	Delivery															
15	Distribution [3]	$ 1,840,463	$ 1,142,280	$ 301,720	$ 185,809	$ 15,961	$ 87,920	$ 571	$ 68,791	$ 2,222	$ 1,227	$ 28,019	$ 3,342	$ -	$ 2,602	
16	Customer	248,945	187,374	35,910	9,094	2,932	5,522	739	5,651	135	76	1,325	82	-	105	
17	Subtotal Delivery	2,089,408	1,329,654	337,630	194,903	18,893	93,442	1,310	74,441	2,357	1,303	29,344	3,424	-	2,707	
	Credit Adjustments [4]															
18	Substation Credits	$ -	$ 1,800	$ 475	$ 293	$ (8)	$ (1,389)	$ 1	$ (345)	$ (321)	$ 2	$ 44	$ 5	$ -	$ (557)	WP-LMC-112
19	Life Line Credits	0	(12,529)	4,112	2,572	425	2,568	125	2,308	167	10	240	-	-	-	WP-LMC-109
20	Total Adjustments	0	(10,729)	4,587	2,865	416	1,179	127	1,964	(154)	12	285	5	-	(557)	
21	Total Delivery Design Target	$ 2,089,408	$ 1,318,925	$ 342,217	$ 197,768	$ 19,310	$ 94,621	$ 1,437	$ 76,405	$ 2,203	$ 1,315	$ 29,629	$ 3,429	$ -	$ 2,150	
22	Total Rate Design Target	$ 4,679,104	$ 2,500,196	$ 716,757	$ 448,217	$ 73,794	$ 445,012	$ 19,216	$ 400,854	$ 28,691	$ 1,790	$ 31,872	$ 10,203	$ -	$ 2,503	
23	DR Surcharge	$ 51,821	$ 21,649	$ 6,517	$ 4,249	$ 894	$ 5,380	$ 7,461	$ 5,169	$ 377	$ 4	$ 19	$ 100	$ -	$ -	WP-LMC-119
24	IRM Surcharge	$ 13,920	$ 8,867	$ 2,252	$ 1,299	$ 126	$ 510	$ 284	$ 330	$ 15	$ 9	$ 196	$ 23	$ -	$ 8	A-68 (LMC-7)
25	Total Revenue Requirement	$ 4,744,845	$ 2,530,712	$ 725,527	$ 453,766	$ 74,814	$ 450,903	$ 26,960	$ 406,354	$ 29,084	$ 1,803	$ 32,087	$ 10,326	$ -	$ 2,511	

Notes
(1) Capacity and energy production costs adjusted to capture elements occurring outside the Cost-of-Service Study
(2) Includes Non-SRM capacity related costs.
(3) Excludes IRM costs recovered through the IRM surcharge.
(4) Credit adjustments approved in Case No. U-21389

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Summer On-peak (RSP)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
Page: 5 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	814,657	MWh	@	0.060410	$ 49,214	0.050649	$ 41,262	$ (7,952)
2	Off-peak kWh	3,560,451	MWh	@	0.041347	147,215	0.034666	123,428	(23,787)
	Capacity								
3	On-peak kWh	814,657	MWh	@	0.053506	43,589	0.062422	50,853	7,264
4	Off-peak kWh	3,560,451	MWh	@	0.036622	130,390	0.042724	152,118	21,728
	Winter (Oct. - May)								
5	Non-capacity All kWh	7,855,392	MWh	@	0.033007	259,279	0.027673	217,385	(41,894)
6	Capacity All kWh	7,855,392	MWh	@	0.029234	229,647	0.034106	267,915	38,268
	Provisions								
	Device Cycling								
7	AC Cycling(1)	270,897	Bills	@	(5.00)	(1,354)	(5.00)	(1,354)	-
8	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
9	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
10	Peak Time Rewards	1,016	MWh	@	(0.50)	(508)	(0.50)	(508)	-
	Critical Peak Pricing								
11	Critical-peak Charge	266	MWh	@	1.00	266	1.00	266	-
12	Off-peak Credits	41,754	MWh	@	(0.006373)	(266)	(0.006373)	(266)	-
13	Annual PSCR Factor	12,230,766	MWh	@	0.009410	115,092	0.009410	115,092	-
14	Total Production					$ 972,564		$ 966,191	$ (6,373)
	Transmission								
	Summer (June - Sept.)								
15	On-peak kWh	814,657	MWh	@	0.037988	$ 30,947	0.037965	$ 30,928	$ (19)
16	Off-peak kWh	3,560,451	MWh	@	0.026001	92,574	0.025985	92,518	(56)
	Winter (Oct. - May)								
17	All kWh	7,855,392	MWh	@	0.020756	163,043	0.020743	162,945	(99)
18	Total Transmission					$ 286,564		$ 286,391	$ (173)
	Delivery								
19	System Access	19,543,128	Bills	@	8.00	$ 156,345	8.00	$ 156,345	$ -
20	Distribution	12,230,766	MWh	@	0.093333	1,141,532	0.093282	1,140,909	(623)
	Provisions								
21	Senior Citizen (RSC)	4,444,922	Bills	@	(4.00)	(17,780)	(4.00)	(17,780)	-
22	Low Income Credit (LIAC)	66,396	Bills	@	(42.00)	(2,789)	(42.00)	(2,789)	-
23	Income Assistance (RIA)	720,358	Bills	@	(8.00)	(5,763)	(8.00)	(5,763)	-
24	Total Delivery					$ 1,271,545		$ 1,270,923	$ (623)
25	Total Full Service					$ 2,530,673		$ 2,523,504	$ (7,169)
	ROA SERVICE								
	Delivery								
26	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
27	Distribution	-	MWh	@	0.093333	-	0.093282	-	-
	Provisions								
28	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
29	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
30	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
31	Total Delivery					$ -		$ -	$ -
32	Total Full & ROA Service					$ 2,530,673		$ 2,523,504	$ (7,169)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Smart Hours (RSH)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
Page: 6 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	11,637	MWh	@	0.060410	$ 703	0.050649	$ 589	$ (114)
2	Off-peak kWh	54,082	MWh	@	0.041347	2,236	0.034666	1,875	(361)
	Capacity								
3	On-peak kWh	11,637	MWh	@	0.053506	623	0.062422	726	104
4	Off-peak kWh	54,082	MWh	@	0.036622	1,981	0.042724	2,311	330
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kWh	17,187	MWh	@	0.038335	659	0.032141	552	(106)
6	Off-peak kWh	95,088	MWh	@	0.031989	3,042	0.026820	2,550	(491)
	Capacity								
7	On-peak kWh	17,187	MWh	@	0.033954	584	0.039612	681	97
8	Off-peak kWh	95,088	MWh	@	0.028333	2,694	0.033054	3,143	449
	Provisions								
	Device Cycling								
9	AC Cycling(1)	3,816	Bills	@	(5.00)	(19)	(5.00)	(19)	-
10	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
11	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
12	Peak Time Rewards	30	MWh	@	(0.50)	(15)	(0.50)	(15)	-
	Critical Peak Pricing								
13	Critical-peak Charge	5	MWh	@	1.00	5	1.00	5	-
14	Off-peak Credits	1,456	MWh	@	(0.006373)	(9)	(0.006373)	(9)	-
15	Annual PSCR Factor	177,999	MWh	@	0.009410	1,675	0.009410	1,675	-
16	Total Production					$ 14,157		$ 14,065	$ (93)
	Transmission								
	Summer (June - Sept.)								
17	On-peak kWh	11,637	MWh	@	0.037988	$ 442	0.037965	$ 442	$ (0)
18	Off-peak kWh	54,082	MWh	@	0.026001	1,406	0.025985	1,405	(1)
	Winter (Oct. - May)								
19	On-peak kWh	17,187	MWh	@	0.024106	414	0.024092	414	(0)
20	Off-peak kWh	95,088	MWh	@	0.020116	1,913	0.020103	1,912	(1)
21	Total Transmission					$ 4,175		$ 4,173	$ (3)
	Delivery								
22	System Access	292,217	Bills	@	8.00	$ 2,338	8.00	$ 2,338	$ -
23	Distribution	177,999	MWh	@	0.093333	16,613	0.093282	16,604	(9)
	Provisions								
24	Senior Citizen (RSC)	48,048	Bills	@	(4.00)	(192)	(4.00)	(192)	-
25	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	13,378	Bills	@	(8.00)	(107)	(8.00)	(107)	-
27	Total Delivery					$ 18,652		$ 18,643	$ (9)
28	Total Full Service					$ 36,984		$ 36,880	$ (104)
	ROA SERVICE								
	Delivery								
29	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
30	Distribution	-	MWh	@	0.093333	-	0.093282	-	-
	Provisions								
31	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
32	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
34	Total Delivery					$ -		$ -	$ -
35	Total Full & ROA Service					$ 36,984		$ 36,880	$ (104)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Nighttime Savers (RPM)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
Page: 7 of 32
Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	9,384	MWh	@	0.060410	$ 567	0.050649	$ 475	$ (92)
2	Off-peak kWh	19,685	MWh	@	0.046196	909	0.038732	762	(147)
3	Super Off-peak kWh	33,466	MWh	@	0.037381	1,251	0.031341	1,049	(202)
	Capacity								
4	On-peak kWh	9,384	MWh	@	0.053506	502	0.062422	586	84
5	Off-peak kWh	19,685	MWh	@	0.040916	805	0.047734	940	134
6	Super Off-peak kWh	33,466	MWh	@	0.033109	1,108	0.038626	1,293	185
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	13,591	MWh	@	0.038335	521	0.032141	437	(84)
8	Off-peak kWh	33,262	MWh	@	0.035960	1,196	0.030150	1,003	(193)
9	Super Off-peak kWh	58,994	MWh	@	0.028890	1,704	0.024222	1,429	(275)
	Capacity								
10	On-peak kWh	13,591	MWh	@	0.033954	461	0.039612	538	77
11	Off-peak kWh	33,262	MWh	@	0.031850	1,059	0.037158	1,236	177
12	Super Off-peak kWh	58,994	MWh	@	0.025588	1,510	0.029852	1,761	252
	Provisions								
	Device Cycling								
13	AC Cycling(1)	4,141	Bills	@	(5.00)	(21)	(5.00)	(21)	-
14	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
15	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
16	Peak Time Rewards	23	MWh	@	(0.50)	(11)	(0.50)	(11)	-
	Critical Peak Pricing								
17	Critical-peak Charge	1	MWh	@	1.00	1	1.00	1	-
18	Off-peak Credits	1,417	MWh	@	(0.006373)	(9)	(0.006373)	(9)	-
19	Annual PSCR Factor	168,382	MWh	@	0.009410	1,584	0.009410	1,584	-
20	Total Production					$ 13,139		$ 13,053	$ (86)
	Transmission								
	Summer (June - Sept.)								
21	On-peak kWh	9,384	MWh	@	0.037988	$ 356	0.037965	$ 356	$ (0)
22	Off-peak kWh	19,685	MWh	@	0.029049	572	0.029032	571	(0)
23	Super Off-peak kWh	33,466	MWh	@	0.023506	787	0.023492	786	(0)
	Winter (Oct. - May)								
24	On-peak kWh	13,591	MWh	@	0.024106	328	0.024092	327	(0)
25	Off-peak kWh	33,262	MWh	@	0.022613	752	0.022599	752	(0)
26	Super Off-peak kWh	58,994	MWh	@	0.018167	1,072	0.018156	1,071	(1)
27	Total Transmission					$ 3,866		$ 3,864	$ (2)
	Delivery								
28	System Access	202,551	Bills	@	8.00	$ 1,620	8.00	$ 1,620	$ -
29	Separately Metered EV Charger	295	Bills	@	(8.00)	$ (2)	(8.00)	$ (2)	$ -
30	Distribution	168,382	MWh	@	0.093333	15,716	0.093282	15,707	(9)
	Provisions								
31	Senior Citizen (RSC)	41,852	Bills	@	(4.00)	(167)	(4.00)	(167)	-
32	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	5,053	Bills	@	(8.00)	(40)	(8.00)	(40)	-
34	Total Delivery					$ 17,126		$ 17,117	$ (9)
35	Total Full Service					$ 34,132		$ 34,035	$ (97)
	ROA SERVICE								
	Delivery								
36	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
37	Distribution	-	MWh	@	0.093333	-	0.093282	-	-
	Provisions								
38	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
39	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
40	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(8.00)	-	-
41	Total Delivery					$ -		$ -	$ -
42	Total Full & ROA Service					$ 34,132		$ 34,035	$ (97)

(1) Proposed revenue reflects change to 3 months

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Non-Transmitting Meters (RSM)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c)	(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE									
	Production									
	Summer (June - Sept.)									
	Non-capacity									
1	First 600 kWh	23,089	MWh	@		0.033007	$ 762	0.027673	$ 639	$ (123)
2	Excess kWh	14,767	MWh	@		0.060410	892	0.050649	748	(144)
	Capacity									
3	First 600 kWh	23,089	MWh	@		0.029234	675	0.034106	787	112
4	Excess kWh	14,767	MWh	@		0.053506	790	0.062422	922	132
	Winter (Oct. - May)									
5	Non-capacity All kWh	70,407	MWh	@		0.033007	2,324	0.027673	1,948	(375)
6	Capacity All kWh	70,407	MWh	@		0.029234	2,058	0.034106	2,401	343
7	Annual PSCR Factor	108,263	MWh	@		0.009410	1,019	0.009410	1,019	-
8	Total Production						$ 8,520		$ 8,465	$ (56)
	Transmission									
	Summer (June - Sept.)									
9	First 600 kWh	23,089	MWh	@		0.020756	$ 479	0.020743	$ 479	$ (0)
10	Excess kWh	14,767	MWh	@		0.037988	561	0.037965	561	(0)
	Winter (Oct. - May)									
11	All kWh	70,407	MWh	@		0.020756	1,461	0.020743	1,460	(1)
12	Total Transmission						$ 2,502		$ 2,500	$ (2)
	Delivery									
13	System Access	131,680	Bills	@		8.00	$ 1,053	8.00	$ 1,053	$ -
14	Opt-out Fee	100,852	Bills	@		12.61	1,272	12.61	1,272	-
15	Distribution	108,263	MWh	@		0.093333	10,104	0.093282	10,099	(6)
	Provisions									
16	Senior Citizen (RSC)	36,309	Bills	@		(4.00)	(145)	(4.00)	(145)	-
17	Low Income Credit (LIAC)	-	Bills	@		(42.00)	-	(42.00)	-	-
18	Income Assistance (RIA)	4,599	Bills	@		(8.00)	(37)	(8.00)	(37)	-
19	Total Delivery						$ 12,248		$ 12,242	$ (6)
20	Total Full Service						$ 23,269		$ 23,207	$ (63)
	ROA SERVICE									
	Delivery									
21	System Access	-	Bills	@		8.00	$ -	8.00	$ -	$ -
22	Opt-out Fee	-	Bills	@		12.61	-	12.61	-	-
23	Distribution	-	MWh	@		0.093333	-	0.093282	-	-
	Provisions									
24	Senior Citizen (RSC)	-	Bills	@		(4.00)	-	(4.00)	-	-
25	Low Income Credit (LIAC)	-	Bills	@		(42.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	-	Bills	@		(8.00)	-	(8.00)	-	-
27	Total Delivery						$ -		$ -	$ -
28	Total Full & ROA Service						$ 23,269		$ 23,207	$ (63)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Energy-only (GS)

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Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	1,447,697	MWh	@	0.046363	$ 67,119	0.039693	$ 57,464	$ (9,655)
2	Capacity All kWh	1,447,697	MWh	@	0.035056	50,750	0.040879	59,180	8,430
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,667,142	MWh	@	0.034013	90,716	0.029120	77,666	(13,050)
4	Capacity All kWh	2,667,142	MWh	@	0.025987	69,310	0.030303	80,823	11,513
5	Annual PSCR Factor	4,114,839	MWh	@	0.009410	38,721	0.009410	38,721	-
6	Total Production					$ 316,616		$ 313,854	$ (2,762)
	Transmission								
	Summer (June - Sept.)								
7	All kWh	1,447,697	MWh	@	0.026688	$ 38,636	0.026672	$ 38,613	$ (23)
	Winter (Oct. - May)								
8	All kWh	2,667,142	MWh	@	0.019784	52,766	0.019772	52,735	(32)
9	Total Transmission					$ 91,403		$ 91,348	$ (55)
	Delivery								
10	System Access	2,459,675	Bills	@	20.00	$ 49,193	20.00	$ 49,193	$ -
11	Distribution	4,114,839	MWh	@	0.069433	285,704	0.069381	285,491	(212)
	Provisions								
12	Education GEI	95,811	MWh	@	(0.001000)	(96)	(0.000995)	(95)	0
13	Total Delivery					$ 334,801		$ 334,590	$ (212)
14	Total Full Service					$ 742,820		$ 739,791	$ (3,029)
	ROA SERVICE								
	Delivery								
15	System Access	1,014	Bills	@	20.00	$ 20	20.00	$ 20	$ -
16	Distribution	18,702	MWh	@	0.069433	1,299	0.069381	1,298	(1)
	Provisions								
17	Education GEI	11,475	MWh	@	(0.001000)	(11)	(0.000995)	(11)	0
18	Total Delivery					$ 1,307		$ 1,306	$ (1)
19	Total Full & ROA Service					$ 744,128		$ 741,098	$ (3,030)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Time-of-Use (GSTU)

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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c) Present Rate $/unit	(d) Present Revenue $000	(e) Proposed Rate $/unit	(f) Proposed Revenue $000	(g) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	14,873	MWh	@	0.062830	$ 934	0.053791	$ 800	$ (134)
2	Mid-peak kWh	11,717	MWh	@	0.048934	573	0.041895	491	(82)
3	Off-peak kWh	4,487	MWh	@	0.036694	165	0.031415	141	(24)
	Capacity								
4	On-peak kWh	14,873	MWh	@	0.047982	714	0.055952	832	119
5	Mid-peak kWh	11,717	MWh	@	0.037369	438	0.043576	511	73
6	Off-peak kWh	4,487	MWh	@	0.028063	126	0.032725	147	21
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	25,578	MWh	@	0.037107	949	0.031769	813	(137)
8	Off-peak kWh	27,907	MWh	@	0.030029	838	0.025709	717	(121)
	Capacity								
9	On-peak kWh	25,578	MWh	@	0.028428	727	0.033150	848	121
10	Off-peak kWh	27,907	MWh	@	0.022961	641	0.026775	747	106
	Provisions								
11	Interruptible (GSI)	-	MWh	@	(0.021695)	-	(0.021695)	-	-
12	Annual PSCR Factor	84,563	MWh	@	0.009410	796	0.009410	796	-
13	Total Production					$ 6,901		$ 6,842	$ (58)
	Transmission								
	Summer (June - Sept.)								
14	On-peak kWh	14,873	MWh	@	0.036529	$ 543	0.036507	$ 543	$ (0)
15	Mid-peak kWh	11,717	MWh	@	0.028449	333	0.028432	333	(0)
16	Off-peak kWh	4,487	MWh	@	0.021365	96	0.021352	96	(0)
	Winter (Oct. - May)								
17	On-peak kWh	25,578	MWh	@	0.021643	554	0.021630	553	(0)
18	Off-peak kWh	27,907	MWh	@	0.017480	488	0.017470	488	(0)
19	Total Transmission					$ 2,014		$ 2,013	$ (1)
	Delivery								
20	System Access	22,689	Bills	@	20.00	$ 454	20.00	$ 454	$ -
21	Distribution	84,563	MWh	@	0.069433	5,871	0.069381	5,867	(4)
	Provisions								
22	Education GEI	-	MWh	@	(0.001000)	-	(0.000995)	-	-
23	Total Delivery					$ 6,325		$ 6,321	$ (4)
24	Total Full Service					$ 15,240		$ 15,176	$ (64)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Demand (GSD)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Peak kW	2,893	MW	@	6.10	$ 17,632	3.43	$ 9,927	$ (7,705)
2	All kWh	1,048,776	MWh	@	0.032526	34,112	0.032350	33,927	(185)
	Capacity								
3	Peak kW	2,893	MW	@	10.17	29,425	11.87	34,328	4,903
4	All kWh	1,048,776	MWh	@	-	-	-	-	-
	Winter (Oct. - May)								
	Non-capacity								
5	Peak kW	5,338	MW	@	2.89	15,402	1.62	8,671	(6,731)
6	All kWh	1,930,830	MWh	@	0.023861	46,072	0.023732	45,823	(249)
	Capacity								
7	Peak kW	5,338	MW	@	9.05	48,326	10.56	56,379	8,053
8	All kWh	1,930,830	MWh	@	-	-	-	-	-
9	Power Factor Adjustment					269		267	(3)
	Provisions								
10	Interruptible (GSI)-Summer	29	MW	@	(8.50)	(247)	(8.50)	(247)	-
11	Interruptible (GSI)-Winter	53	MW	@	(7.50)	(398)	(7.50)	(398)	-
12	Annual PSCR Factor	2,979,606	MWh	@	0.009410	28,038	0.009410	28,038	-
13	Total Production					$ 218,633		$ 216,716	$ (1,917)
	Transmission								
	Summer (June - Sept.)								
14	Peak kW	2,893	MW	@	8.00	$ 23,147	8.00	$ 23,133	$ (14)
	Winter (Oct. - May)								
15	Peak kW	5,338	MW	@	7.12	38,017	7.12	37,994	(23)
16	Total Transmission					$ 61,164		$ 61,127	$ (37)
	Delivery								
17	System Access	241,823	Bills	@	30.00	$ 7,255	30.00	$ 7,255	$ -
18	Peak kW	8,231	MW	@	1.00	8,231	1.00	8,231	-
19	Distribution	2,979,606	MWh	@	0.057650	171,774	0.057599	171,622	(152)
20	Power Factor Adjustment					254		254	(0)
	Provisions								
21	Education GEI	131,112	MWh	@	(0.000820)	(107)	(0.000816)	(107)	1
22	Total Delivery					$ 187,406		$ 187,254	$ (152)
23	Total Full Service					$ 467,203		$ 465,098	$ (2,106)
	ROA SERVICE								
	Delivery								
24	System Access	5,663	Bills	@	30.00	$ 170	30.00	$ 170	$ -
25	Peak kW	344	MW	@	1.00	344	1.00	344	-
26	Distribution	174,288	MWh	@	0.057650	10,048	0.057599	10,039	(9)
27	Power Factor Adjustment					16		16	(0)
	Provisions								
28	Education GEI	68,199	MWh	@	(0.000820)	(56)	(0.000816)	(56)	0
29	Total Delivery					$ 10,522		$ 10,513	$ (9)
30	Total Full & ROA Service					$ 477,725		$ 475,611	$ (2,114)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 1 (GP VL 1)

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Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	1,101	MWh	@	0.043974	$ 48	0.038553	$ 42	$ (6)
2	Capacity All kWh	1,101	MWh	@	0.027595	30	0.032208	35	5
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,353	MWh	@	0.032261	76	0.028283	67	(9)
4	Capacity All kWh	2,353	MWh	@	0.021049	50	0.024568	58	8
5	Power Factor Adjustment					3		3	(0)
6	Annual PSCR Factor	3,454	MWh	@	0.009410	33	0.009410	33	-
7	Total Production					$ 240		$ 238	$ (2)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	1,101	MWh	@	0.023364	$ 26	0.023350	$ 26	$ (0)
	Winter (Oct. - May)								
9	All kWh	2,353	MWh	@	0.017822	42	0.017812	42	(0)
10	Total Transmission					$ 68		$ 68	$ (0)
	Delivery								
11	System Access	49	Bills	@	100.00	$ 5	100.00	$ 5	$ -
12	Distribution	3,454	MWh	@	0.006957	24	0.006916	24	(0)
13	Substation Ownership Credit	700	MWh	@	(0.004093)	(3)	(0.004093)	(3)	-
14	Power Factor Adjustment					0		0	(0)
	Provisions								
15	Education GEI	-	MWh	@	(0.000578)	-	(0.000574)	-	-
16	Total Delivery					$ 26		$ 26	$ (0)
17	Total Full Service					$ 334		$ 332	$ (2)
	ROA SERVICE								
	Delivery								
18	System Access	-	Bills	@	100.00	$ -	100.00	$ -	$ -
19	Distribution	-	MWh	@	0.006957	-	0.006916	-	-
20	Substation Ownership Credit	-	MWh	@	(0.004093)	-	(0.004093)	-	-
21	Power Factor Adjustment					-		-	-
	Provisions								
22	Education GEI	-	MWh	@	(0.000578)	-	(0.000574)	-	-
23	Total Delivery					$ -		$ -	$ -
24	Total Full & ROA Service					$ 334		$ 332	$ (2)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 2 (GP VL 2)

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Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	9,485	MWh	@	0.044489	$ 422	0.039004	$ 370	$ (52)
2	Capacity All kWh	9,485	MWh	@	0.027998	266	0.032678	310	44
	Winter (Oct. - May)								
3	Non-capacity All kWh	21,775	MWh	@	0.032638	711	0.028614	623	(88)
4	Capacity All kWh	21,775	MWh	@	0.021357	465	0.024927	543	78
5	Power Factor Adjustment					49		48	(0)
6	Annual PSCR Factor	31,259	MWh	@	0.009410	294	0.009410	294	-
7	Total Production					$ 2,206		$ 2,188	$ (18)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	9,485	MWh	@	0.023706	$ 225	0.023691	$ 225	$ (0)
	Winter (Oct. - May)								
9	All kWh	21,775	MWh	@	0.018083	394	0.018072	394	(0)
10	Total Transmission					$ 619		$ 618	$ (0)
	Delivery								
11	System Access	435	Bills	@	100.00	$ 43	100.00	$ 43	$ -
12	Distribution	31,259	MWh	@	0.010996	344	0.010954	342	(1)
13	Substation Ownership Credit	6,580	MWh	@	(0.004513)	(30)	(0.004513)	(30)	-
14	Power Factor Adjustment					8		8	(0)
	Provisions								
15	Education GEI	-	MWh	@	(0.000578)	-	(0.000574)	-	-
16	Total Delivery					$ 366		$ 364	$ (1)
17	Total Full Service					$ 3,191		$ 3,171	$ (20)
	ROA SERVICE								
	Delivery								
18	System Access	24	Bills	@	100.00	$ 2	100.00	$ 2	$ -
19	Distribution	1,783	MWh	@	0.010996	20	0.010954	20	(0)
20	Substation Ownership Credit	-	MWh	@	(0.004513)	-	(0.004513)	-	-
21	Power Factor Adjustment					(0)		(0)	0
	Provisions								
22	Education GEI	-	MWh	@	(0.000578)	-	(0.000574)	-	-
23	Total Delivery					$ 22		$ 22	$ (0)
24	Total Full & ROA Service					$ 3,212		$ 3,193	$ (20)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 3 (GP VL 3)

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Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	221,271	MWh	@	0.044937	$ 9,943	0.039397	$ 8,717	$ (1,226)
2	Capacity All kWh	221,271	MWh	@	0.028442	6,293	0.033196	7,345	1,052
	Winter (Oct. - May)								
3	Non-capacity All kWh	410,967	MWh	@	0.032967	13,548	0.028903	11,878	(1,670)
4	Capacity All kWh	410,967	MWh	@	0.021696	8,916	0.025322	10,407	1,490
5	Power Factor Adjustment					486		481	(4)
6	Annual PSCR Factor	632,239	MWh	@	0.009410	5,949	0.009410	5,949	-
7	Total Production					$ 45,136		$ 44,778	$ (358)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	221,271	MWh	@	0.024082	$ 5,329	0.024067	$ 5,325	$ (3)
	Winter (Oct. - May)								
9	All kWh	410,967	MWh	@	0.018370	7,549	0.018358	7,545	(5)
10	Total Transmission					$ 12,878		$ 12,870	$ (8)
	Delivery								
11	System Access	15,834	Bills	@	100.00	$ 1,583	100.00	$ 1,583	$ -
12	Distribution	632,239	MWh	@	0.024415	15,436	0.024363	15,403	(33)
13	Power Factor Adjustment					194		193	(0)
	Provisions								
14	Education GEI	85,102	MWh	@	(0.000578)	(49)	(0.000574)	(49)	0
15	Total Delivery					$ 17,164		$ 17,131	$ (33)
16	Total Full Service					$ 75,178		$ 74,779	$ (399)
	ROA SERVICE								
	Delivery								
17	System Access	696	Bills	@	100.00	$ 70	100.00	$ 70	$ -
18	Distribution	70,285	MWh	@	0.024415	1,716	0.024363	1,712	(4)
19	Power Factor Adjustment					5		5	(0)
	Provisions								
20	Education GEI	36,890	MWh	@	(0.000578)	(21)	(0.000574)	(21)	0
21	Total Delivery					$ 1,770		$ 1,766	$ (4)
22	Total Full & ROA Service					$ 76,948		$ 76,545	$ (402)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 1 (GPD VL 1)

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Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	668	MW	@	5.96	$ 3,979	3.95	$ 2,637	$ (1,342)
2	On-peak kWh	86,218	MWh	@	0.040427	3,486	0.040286	3,473	(12)
3	Off-peak kWh	296,066	MWh	@	0.026219	7,762	0.026127	7,735	(27)
4	Capacity On-peak kW	668	MW	@	10.06	6,719	11.76	7,854	1,135
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,369	MW	@	5.15	7,050	3.41	4,672	(2,377)
6	On-peak kWh	179,258	MWh	@	0.025351	4,544	0.025263	4,529	(16)
7	Off-peak kWh	605,998	MWh	@	0.022012	13,339	0.021936	13,293	(47)
8	Capacity On-peak kW	1,369	MW	@	9.33	12,777	10.91	14,935	2,158
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	60	MW	@	(8.50)	(514)	(8.50)	(514)	-
11	Winter Contracted kW	121	MW	@	(7.50)	(905)	(7.50)	(905)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.029081	-	0.028530	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.026985	-	0.026696	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.027445	-	-
16	Summer Transmission	-	MWh		-	-	0.015930	-	-
17	Winter Capacity	-	MWh		-	-	0.024969	-	-
18	Winter Transmission	-	MWh		-	-	0.014804	-	-
19	Critical Peak Event	-	MWh		-	-	1.00	-	-
20	Power Factor Adjustment					(122)		(121)	1
21	Annual PSCR Factor	1,167,540	MWh	@	0.009410	10,987	0.009410	10,987	-
22	Total Production					$ 69,103		$ 68,576	$ (527)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	668	MW	@	9.13	$ 6,094	9.12	$ 6,090	$ (4)
	Winter (Oct. - May)								
24	On-peak kW	1,369	MW	@	8.50	11,632	8.49	11,625	(7)
25	Total Transmission					$ 17,725		$ 17,714	$ (11)
	Delivery								
26	System Access	267	Bills	@	200.00	$ 53	200.00	$ 53	$ -
27	Maximum kW	2,528	MW	@	2.37	5,996	2.36	5,965	(31)
28	Substation Ownership	42	MW	@	(1.82)	(76)	(1.82)	(76)	-
29	Distribution	1,167,540	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(12)		(12)	0
	Provisions								
31	Education GEI	-	MWh	@	(0.000205)	-	(0.000204)	-	-
32	Total Delivery					$ 5,961		$ 5,930	$ (31)
33	Total Full Service					$ 92,789		$ 92,220	$ (568)
	ROA SERVICE								
	Delivery								
34	System Access	169	Bills	@	200.00	$ 34	200.00	$ 34	$ -
35	Maximum kW	2,403	MW	@	2.37	5,700	2.36	5,671	(29)
36	Substation Ownership	196	MW	@	(1.82)	(356)	(1.82)	(356)	-
37	Distribution	1,270,576	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					(14)		(14)	0
	Provisions								
39	Education GEI	2,675	MWh	@	(0.000205)	(1)	(0.000204)	(1)	0
40	Total Delivery					$ 5,364		$ 5,335	$ (29)
41	Total Full & ROA Service					$ 98,153		$ 97,555	$ (598)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 2 (GPD VL 2)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	886	MW	@	6.03	$ 5,340	4.00	$ 3,539	$ (1,801)
2	On-peak kWh	121,063	MWh	@	0.040900	4,951	0.040757	4,934	(17)
3	Off-peak kWh	357,634	MWh	@	0.026526	9,486	0.026433	9,453	(33)
4	Capacity On-peak kW	886	MW	@	10.21	9,042	11.94	10,569	1,527
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,801	MW	@	5.21	9,381	3.45	6,218	(3,164)
6	On-peak kWh	240,894	MWh	@	0.025648	6,178	0.025558	6,157	(22)
7	Off-peak kWh	733,449	MWh	@	0.022270	16,334	0.022192	16,277	(57)
8	Capacity On-peak kW	1,801	MW	@	9.47	17,051	11.07	19,931	2,880
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	40	MW	@	(8.50)	(343)	(8.50)	(343)	-
11	Winter Contracted kW	81	MW	@	(7.50)	(608)	(7.50)	(608)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.031449	-	0.030868	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.029198	-	0.028897	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.029473	-	-
16	Summer Transmission	-	MWh		-	-	0.017119	-	-
17	Winter Capacity	-	MWh		-	-	0.026837	-	-
18	Winter Transmission	-	MWh		-	-	0.008411	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					(103)		(102)	1
21	Annual PSCR Factor	1,453,040	MWh	@	0.009410	13,673	0.009410	13,673	-
22	Total Production					$ 90,384		$ 89,698	$ (685)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	886	MW	@	9.26	$ 8,200	9.25	$ 8,195	$ (5)
	Winter (Oct. - May)								
24	On-peak kW	1,801	MW	@	8.62	15,523	8.61	15,514	(9)
25	Total Transmission					$ 23,723		$ 23,708	$ (14)
	Delivery								
26	System Access	721	Bills	@	200.00	$ 144	200.00	$ 144	$ -
27	Maximum kW	3,094	MW	@	3.61	11,178	3.60	11,143	(35)
28	Substation Ownership	269	MW	@	(1.93)	(520)	(1.93)	(520)	-
29	Distribution	1,453,040	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(14)		(14)	0
	Provisions								
31	Education GEI	29,734	MWh	@	(0.000205)	(6)	(0.000204)	(6)	0
32	Total Delivery					$ 10,782		$ 10,747	$ (35)
33	Total Full Service					$ 124,888		$ 124,154	$ (735)
	ROA SERVICE								
	Delivery								
34	System Access	453	Bills	@	200.00	$ 91	200.00	$ 91	$ -
35	Maximum kW	2,306	MW	@	3.61	8,331	3.60	8,305	(26)
36	Substation Ownership	298	MW	@	(1.93)	(576)	(1.93)	(576)	-
37	Distribution	1,080,207	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					16		16	(0)
	Provisions								
39	Education GEI	66,701	MWh	@	(0.000205)	(14)	(0.000204)	(14)	0
40	Total Delivery					$ 7,848		$ 7,822	$ (26)
41	Total Full & ROA Service					$ 132,737		$ 131,976	$ (761)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 3 (GPD VL 3)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
Page: 17 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	1,514	MW	@	6.09	$ 9,218	4.04	$ 6,110	$ (3,108)
2	On-peak kWh	209,315	MWh	@	0.041312	8,647	0.041168	8,617	(30)
3	Off-peak kWh	587,189	MWh	@	0.026793	15,733	0.026699	15,678	(55)
4	Capacity On-peak kW	1,514	MW	@	10.37	15,697	12.12	18,353	2,656
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	3,075	MW	@	5.26	16,175	3.49	10,724	(5,451)
6	On-peak kWh	417,471	MWh	@	0.025907	10,815	0.025816	10,777	(38)
7	Off-peak kWh	1,200,805	MWh	@	0.022495	27,012	0.022416	26,917	(95)
8	Capacity On-peak kW	3,075	MW	@	9.62	29,583	11.24	34,575	4,992
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	4	MW	@	(8.50)	(34)	(8.50)	(34)	-
11	Winter Contracted kW	8	MW	@	(7.50)	(57)	(7.50)	(57)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.033010	-	0.032426	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.031900	-	0.031604	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.030714	-	-
16	Summer Transmission	-	MWh		-	-	0.017866	-	-
17	Winter Capacity	-	MWh		-	-	0.027992	-	-
18	Winter Transmission	-	MWh		-	-	0.016630	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					91		91	(1)
21	Annual PSCR Factor	2,414,780	MWh	@	0.009410	22,723	0.009410	22,723	-
22	Total Production					$ 155,603		$ 154,474	$ (1,130)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	1,514	MW	@	9.41	$ 14,244	9.40	$ 14,230	$ (14)
	Winter (Oct. - May)								
24	On-peak kW	3,075	MW	@	8.76	26,938	8.75	26,911	(27)
25	Total Transmission					$ 41,182		$ 41,141	$ (40)
	Delivery								
26	System Access	9,273	Bills	@	200.00	$ 1,855	200.00	$ 1,855	$ -
27	Maximum kW	5,899	MW	@	6.68	39,405	6.67	39,358	(46)
28	Distribution	2,414,780	MWh	@	-	-	-	-	-
29	Power Factor Adjustment					27		27	(0)
	Provisions								
30	Education GEI	110,078	MWh	@	(0.000204)	(22)	(0.000204)	(22)	0
31	Total Delivery					$ 41,264		$ 41,218	$ (46)
32	Total Full Service					$ 238,049		$ 236,833	$ (1,216)
	ROA SERVICE								
	Delivery								
33	System Access	3,656	Bills	@	200.00	$ 731	200.00	$ 731	$ -
34	Maximum kW	2,542	MW	@	6.68	16,986	6.67	16,962	(24)
35	Distribution	953,091	MWh	@	-	-	-	-	-
36	Power Factor Adjustment					37		37	(0)
	Provisions								
37	Education GEI	149,120	MWh	@	(0.000204)	(30)	(0.000204)	(30)	0
38	Total Delivery					$ 17,724		$ 17,700	$ (24)
39	Total Full & ROA Service					$ 255,773		$ 254,533	$ (1,241)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Large Load Voltage Level 1

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	3,600	MW	@	5.96	$ -	15.53	$ 55,907	$ 55,907
2	On-peak kWh	878,400	MWh	@	0.040427	-	(0.078772)	(69,193)	(69,193)
3	Off-peak kWh	1,756,800	MWh	@	0.026219	-	(0.051087)	(89,750)	(89,750)
4	Capacity On-peak kW	3,600	MW	@	10.06	-	13.32	47,942	47,942
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	7,200	MW	@	5.15	-	13.42	96,599	96,599
6	On-peak kWh	1,749,600	MWh	@	0.025351	-	(0.049397)	(86,425)	(86,425)
7	Off-peak kWh	3,499,200	MWh	@	0.022012	-	(0.042891)	(150,085)	(150,085)
8	Capacity On-peak kW	7,200	MW	@	9.33	-	12.35	88,913	88,913
	Provisions								
20	Power Factor Adjustment					-			-
21	Annual PSCR Factor	7,884,000	MWh	@	0.009410	-	0.009410	74,188	74,188
22	Total Production					$ -		$ (31,904)	$ (31,904)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	3,600	MW	@	9.13	$ -	12.02	$ 43,285	$ 43,285
	Winter (Oct. - May)								
24	On-peak kW	7,200	MW	@	8.50	-	11.19	80,587	80,587
25	Total Transmission					$ -		$ 123,871	$ 123,871
	Delivery								
26	System Access	12	Bills	@	200.00	$ -	200.00	$ 2	$ 2
27	Maximum kW	10,800	MW	@	2.37	-	0.13	1,434	1,434
28	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
29	Distribution	7,884,000	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					-			-
	Provisions								
31	Education GEI	-	MWh	@	(0.000205)	-	(0.000142)	-	-
32	Total Delivery					$ -		$ 1,437	$ 1,437
33	Total Full Service					$ -		$ 93,404	$ 93,404

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 1 (GPTU VL 1)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	13,186	MWh	@	0.061877	$ 816	0.054769	$ 722	$ (94)
2	Mid-peak kWh	17,748	MWh	@	0.055068	977	0.048742	865	(112)
3	Low-peak kWh	48,608	MWh	@	0.044513	2,164	0.039400	1,915	(249)
4	Off-peak kWh	86,924	MWh	@	0.033174	2,884	0.029363	2,552	(331)
	Capacity								
5	High-peak kWh	13,186	MWh	@	0.035267	465	0.041146	543	78
6	Mid-peak kWh	17,748	MWh	@	0.031400	557	0.036634	650	93
7	Low-peak kWh	48,608	MWh	@	0.025306	1,230	0.029524	1,435	205
8	Off-peak kWh	86,924	MWh	@	0.018927	1,645	0.022083	1,920	274
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	26,006	MWh	@	0.039842	1,036	0.035266	917	(119)
10	Mid-peak kWh	36,415	MWh	@	0.036938	1,345	0.032695	1,191	(155)
11	Off-peak kWh	235,629	MWh	@	0.031011	7,307	0.027448	6,468	(839)
	Capacity								
12	High-peak kWh	26,006	MWh	@	0.022720	591	0.026507	689	98
13	Mid-peak kWh	36,415	MWh	@	0.021035	766	0.024541	894	128
14	Off-peak kWh	235,629	MWh	@	0.017499	4,123	0.020416	4,811	687
15	Power Factor Adjustment					42		41	(1)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	464,518	MWh	@	0.009410	4,371	0.009410	4,371	-
19	Total Production					$ 30,320		$ 29,984	$ (336)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	13,186	MWh	@	0.030861	$ 407	0.030843	$ 407	$ (0)
21	Mid-peak kWh	17,748	MWh	@	0.027477	488	0.027461	487	(0)
22	Low-peak kWh	48,608	MWh	@	0.022144	1,076	0.022131	1,076	(1)
23	Off-peak kWh	86,924	MWh	@	0.016563	1,440	0.016553	1,439	(1)
24	Winter (Oct. - May)								
25	High-peak kWh	26,006	MWh	@	0.019881	517	0.019869	517	(0)
26	Mid-peak kWh	36,415	MWh	@	0.018407	670	0.018396	670	(0)
27	Off-peak kWh	235,629	MWh	@	0.015313	3,608	0.015304	3,606	(2)
28	Total Transmission					$ 8,206		$ 8,201	$ (5)
	Delivery								
29	System Access	280	Bills	@	200.00	$ 56	200.00	$ 56	$ -
30	Maximum kW	1,315	MW	@	2.37	3,119	2.36	3,103	(16)
31	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
32	Distribution	464,518	MWh	@	-	-	-	-	-
33	Power Factor Adjustment					5		5	(0)
	Provisions								
34	Education GEI	39,403	MWh	@	(0.000205)	(8)	(0.000204)	(8)	0
35	Total Delivery					$ 3,172		$ 3,156	$ (16)
36	Total Full Service					$ 41,698		$ 41,341	$ (357)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 2 (GPTU VL 2)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	16,699	MWh	@	0.062601	$ 1,045	0.055410	$ 925	$ (120)
2	Mid-peak kWh	22,367	MWh	@	0.055712	1,246	0.049312	1,103	(143)
3	Low-peak kWh	51,905	MWh	@	0.045034	2,337	0.039861	2,069	(269)
4	Off-peak kWh	84,694	MWh	@	0.033562	2,843	0.029707	2,516	(327)
	Capacity								
5	High-peak kWh	16,699	MWh	@	0.035782	598	0.041747	697	100
6	Mid-peak kWh	22,367	MWh	@	0.031859	713	0.037169	831	119
7	Low-peak kWh	51,905	MWh	@	0.025675	1,333	0.029955	1,555	222
8	Off-peak kWh	84,694	MWh	@	0.019204	1,626	0.022405	1,898	271
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	32,702	MWh	@	0.040309	1,318	0.035678	1,167	(151)
10	Mid-peak kWh	44,338	MWh	@	0.037370	1,657	0.033077	1,467	(190)
11	Off-peak kWh	243,938	MWh	@	0.031374	7,653	0.027770	6,774	(879)
	Capacity								
12	High-peak kWh	32,702	MWh	@	0.023051	754	0.026894	879	126
13	Mid-peak kWh	44,338	MWh	@	0.021342	946	0.024899	1,104	158
14	Off-peak kWh	243,938	MWh	@	0.017754	4,331	0.020714	5,053	722
15	Power Factor Adjustment					(12)		(12)	0
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	496,642	MWh	@	0.009410	4,673	0.009410	4,673	-
19	Total Production					$ 33,061		$ 32,699	$ (362)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	16,699	MWh	@	0.031312	$ 523	0.031293	$ 523	$ (0)
21	Mid-peak kWh	22,367	MWh	@	0.027879	624	0.027862	623	(0)
22	Low-peak kWh	51,905	MWh	@	0.022468	1,166	0.022454	1,165	(1)
23	Off-peak kWh	84,694	MWh	@	0.016805	1,423	0.016795	1,422	(1)
	Winter (Oct. - May)								
24	High-peak kWh	32,702	MWh	@	0.020172	660	0.020159	659	(0)
25	Mid-peak kWh	44,338	MWh	@	0.018676	828	0.018664	828	(1)
26	Off-peak kWh	243,938	MWh	@	0.015536	3,790	0.015527	3,788	(2)
27	Total Transmission					$ 9,013		$ 9,008	$ (5)
	Delivery								
28	System Access	963	Bills	@	200.00	$ 193	200.00	$ 193	$ -
29	Maximum kW	1,431	MW	@	3.61	5,168	3.60	5,152	(16)
30	Substation Ownership	235	MW	@	(1.93)	(453)	(1.93)	(453)	-
31	Distribution	496,642	MWh	@	-	-	-	-	-
32	Power Factor Adjustment					(2)		(2)	0
	Provisions								
33	Education GEI	18,544	MWh	@	(0.000205)	(4)	(0.000204)	(4)	0
34	Total Delivery					$ 4,902		$ 4,886	$ (16)
35	Total Full Service					$ 46,976		$ 46,593	$ (384)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 3 (GPTU VL 3)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
Page: 21 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	127,203	MWh	@	0.063232	$ 8,043	0.055969	$ 7,119	$ (924)
2	Mid-peak kWh	168,181	MWh	@	0.056274	9,464	0.049809	8,377	(1,087)
3	Low-peak kWh	375,163	MWh	@	0.045488	17,065	0.040263	15,105	(1,960)
4	Off-peak kWh	562,171	MWh	@	0.033901	19,058	0.030006	16,869	(2,189)
	Capacity								
5	High-peak kWh	127,203	MWh	@	0.036350	4,624	0.042409	5,395	771
6	Mid-peak kWh	168,181	MWh	@	0.032364	5,443	0.037759	6,350	907
7	Low-peak kWh	375,163	MWh	@	0.026083	9,785	0.030430	11,416	1,631
8	Off-peak kWh	562,171	MWh	@	0.019509	10,967	0.022761	12,795	1,828
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	216,061	MWh	@	0.040715	8,797	0.036038	7,786	(1,011)
10	Mid-peak kWh	295,549	MWh	@	0.037747	11,156	0.033411	9,875	(1,282)
11	Off-peak kWh	1,567,912	MWh	@	0.031690	49,687	0.028050	43,979	(5,708)
	Capacity								
12	High-peak kWh	216,061	MWh	@	0.023417	5,060	0.027320	5,903	843
13	Mid-peak kWh	295,549	MWh	@	0.021680	6,408	0.025294	7,476	1,068
14	Off-peak kWh	1,567,912	MWh	@	0.018036	28,279	0.021043	32,993	4,714
15	Power Factor Adjustment					456		450	(6)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	3,312,240	MWh	@	0.009410	31,168	0.009410	31,168	-
19	Total Production					$ 225,460		$ 223,057	$ (2,403)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	127,203	MWh	@	0.031809	$ 4,046	0.031790	$ 4,044	$ (2)
21	Mid-peak kWh	168,181	MWh	@	0.028321	4,763	0.028304	4,760	(3)
22	Low-peak kWh	375,163	MWh	@	0.022824	8,563	0.022810	8,558	(5)
23	Off-peak kWh	562,171	MWh	@	0.017071	9,597	0.017061	9,591	(6)
	Winter (Oct. - May)								
24	High-peak kWh	216,061	MWh	@	0.020492	4,427	0.020479	4,425	(3)
25	Mid-peak kWh	295,549	MWh	@	0.018972	5,607	0.018961	5,604	(3)
26	Off-peak kWh	1,567,912	MWh	@	0.015783	24,746	0.015773	24,731	(15)
27	Total Transmission					$ 61,750		$ 61,713	$ (37)
	Delivery								
28	System Access	16,957	Bills	@	200.00	$ 3,391	200.00	$ 3,391	$ -
29	Maximum kW	10,275	MW	@	6.68	68,656	6.67	68,559	(97)
30	Distribution	3,312,240	MWh	@	-	-	-	-	-
31	Power Factor Adjustment					161		161	(0)
	Provisions								
32	Education GEI	278,712	MWh	@	(0.000204)	(57)	(0.000204)	(57)	0
33	Total Delivery					$ 72,152		$ 72,055	$ (97)
34	Total Full Service					$ 359,362		$ 356,824	$ (2,538)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 1 (EIP VL 1)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	206	MWh	@	0.099498	$ 21	0.091491	$ 19	$ (2)
2	High-peak kWh	7,015	MWh	@	0.066332	465	0.060994	428	(37)
3	Mid-peak kWh	7,214	MWh	@	0.059487	429	0.054700	395	(35)
4	Low-peak kWh	45,458	MWh	@	0.047278	2,149	0.043474	1,976	(173)
5	Off-peak kWh	61,205	MWh	@	0.034619	2,119	0.031834	1,948	(171)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	206	MWh	@	0.040218	8	0.047095	10	1
8	High-peak kWh	7,015	MWh	@	0.026812	188	0.031397	220	32
9	Mid-peak kWh	7,214	MWh	@	0.023872	172	0.027954	202	29
10	Low-peak kWh	45,458	MWh	@	0.019239	875	0.022529	1,024	150
11	Off-peak kWh	61,205	MWh	@	0.014390	881	0.016850	1,031	151
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	647	MWh	@	0.062127	40	0.057128	37	(3)
13	High-peak kWh	14,105	MWh	@	0.041418	584	0.038085	537	(47)
14	Mid-peak kWh	14,704	MWh	@	0.038779	570	0.035658	524	(46)
15	Off-peak kWh	182,038	MWh	@	0.032609	5,936	0.029985	5,458	(478)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	647	MWh	@	0.025909	17	0.030339	20	3
18	High-peak kWh	14,105	MWh	@	0.017272	244	0.020226	285	42
19	Mid-peak kWh	14,704	MWh	@	0.015992	235	0.018726	275	40
20	Off-peak kWh	182,038	MWh	@	0.013303	2,422	0.015579	2,836	414
21	Power Factor Adjustment					7		7	(0)
22	Interruptible Credit	332,592	MWh	@	(0.008461)	(2,814)	(0.008461)	(2,814)	-
23	Annual PSCR Factor	332,592	MWh	@	0.009410	3,130	0.009410	3,130	-
24	Total Production					$ 17,677		$ 17,548	$ (129)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	206	MWh	@	0.041546	$ 9	0.041521	$ 9	$ (0)
26	High-peak kWh	7,015	MWh	@	0.027698	194	0.027681	194	(0)
27	Mid-peak kWh	7,214	MWh	@	0.024660	178	0.024646	178	(0)
28	Low-peak kWh	45,458	MWh	@	0.019874	903	0.019862	903	(1)
29	Off-peak kWh	61,205	MWh	@	0.014865	910	0.014856	909	(1)
	Winter (Oct. - May)								
30	Critical-peak kWh	647	MWh	@	0.026765	17	0.026748	17	(0)
31	High-peak kWh	14,105	MWh	@	0.017843	252	0.017832	252	(0)
32	Mid-peak kWh	14,704	MWh	@	0.016520	243	0.016510	243	(0)
33	Off-peak kWh	182,038	MWh	@	0.013743	2,502	0.013735	2,500	(2)
34	Total Transmission					$ 5,208		$ 5,205	$ (3)
	Delivery								
35	System Access	64	Bills	@	200.00	$ 13	200.00	$ 13	$ -
36	Maximum kW	771	MW	@	2.37	1,830	2.36	1,820	(9)
37	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
38	Power Factor Adjustment					1		1	(0)
39	Distribution	332,592	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,843		$ 1,834	$ (9)
41	Total Full Service					$ 24,728		$ 24,587	$ (141)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 2 (EIP VL 2)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
Page: 23 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	27	MWh	@	0.100662	$ 3	0.092562	$ 2	$ (0)
2	High-peak kWh	895	MWh	@	0.067108	60	0.061708	55	(5)
3	Mid-peak kWh	937	MWh	@	0.060183	56	0.055340	52	(5)
4	Low-peak kWh	7,371	MWh	@	0.047832	353	0.043983	324	(28)
5	Off-peak kWh	10,461	MWh	@	0.035024	366	0.032206	337	(29)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	27	MWh	@	0.040805	1	0.047783	1	0
8	High-peak kWh	895	MWh	@	0.027203	24	0.031855	29	4
9	Mid-peak kWh	937	MWh	@	0.024220	23	0.028362	27	4
10	Low-peak kWh	7,371	MWh	@	0.019519	144	0.022858	168	25
11	Off-peak kWh	10,461	MWh	@	0.014600	153	0.017096	179	26
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	79	MWh	@	0.062854	5	0.057796	5	(0)
13	High-peak kWh	1,503	MWh	@	0.041903	63	0.038531	58	(5)
14	Mid-peak kWh	1,737	MWh	@	0.039232	68	0.036075	63	(5)
15	Off-peak kWh	30,227	MWh	@	0.032990	997	0.030335	917	(80)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	79	MWh	@	0.026287	2	0.030782	2	0
18	High-peak kWh	1,503	MWh	@	0.017525	26	0.020522	31	5
19	Mid-peak kWh	1,737	MWh	@	0.016225	28	0.019000	33	5
20	Off-peak kWh	30,227	MWh	@	0.013498	408	0.015806	478	70
21	Power Factor Adjustment					(14)		(14)	0
22	Interruptible Credit	53,237	MWh	@	(0.008461)	(450)	(0.008461)	(450)	-
23	Annual PSCR Factor	53,237	MWh	@	0.009410	501	0.009410	501	-
24	Total Production					$ 2,817		$ 2,797	$ (20)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	27	MWh	@	0.042153	$ 1	0.042127	$ 1	$ (0)
26	High-peak kWh	895	MWh	@	0.028102	25	0.028085	25	(0)
27	Mid-peak kWh	937	MWh	@	0.025021	23	0.025005	23	(0)
28	Low-peak kWh	7,371	MWh	@	0.020164	149	0.020152	149	(0)
29	Off-peak kWh	10,461	MWh	@	0.015082	158	0.015073	158	(0)
	Winter (Oct. - May)								
30	Critical-peak kWh	79	MWh	@	0.027155	2	0.027139	2	(0)
31	High-peak kWh	1,503	MWh	@	0.018104	27	0.018093	27	(0)
32	Mid-peak kWh	1,737	MWh	@	0.016761	29	0.016751	29	(0)
33	Off-peak kWh	30,227	MWh	@	0.013944	421	0.013935	421	(0)
34	Total Transmission					$ 836		$ 836	$ (1)
	Delivery								
35	System Access	82	Bills	@	200.00	$ 16	200.00	$ 16	$ -
36	Maximum kW	373	MW	@	3.61	1,347	3.60	1,342	(4)
37	Substation Ownership	169	MW	@	(1.93)	(326)	(1.93)	(326)	-
38	Power Factor Adjustment					(5)		(5)	0
39	Distribution	53,237	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,032		$ 1,028	$ (4)
41	Total Full Service					$ 4,685		$ 4,660	$ (25)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 3 (EIP VL 3)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
Page: 24 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c) Present Rate $/unit	(d) Present Revenue $000	(e) Proposed Rate $/unit	(f) Proposed Revenue $000	(g) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	1	MWh	@	0.101677	$ 0	0.093495	$ 0	$ (0)
2	High-peak kWh	66	MWh	@	0.067784	5	0.062330	4	(0)
3	Mid-peak kWh	104	MWh	@	0.060790	6	0.055898	6	(1)
4	Low-peak kWh	1,569	MWh	@	0.048314	76	0.044426	70	(6)
5	Off-peak kWh	908	MWh	@	0.035378	32	0.032531	30	(3)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	1	MWh	@	0.041452	0	0.048541	0	0
8	High-peak kWh	66	MWh	@	0.027635	2	0.032361	2	0
9	Mid-peak kWh	104	MWh	@	0.024605	3	0.028812	3	0
10	Low-peak kWh	1,569	MWh	@	0.019829	31	0.023220	36	5
11	Off-peak kWh	908	MWh	@	0.014831	13	0.017368	16	2
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	4	MWh	@	0.063488	0	0.058379	0	(0)
13	High-peak kWh	93	MWh	@	0.042325	4	0.038919	4	(0)
14	Mid-peak kWh	119	MWh	@	0.039628	5	0.036439	4	(0)
15	Off-peak kWh	3,871	MWh	@	0.033323	129	0.030641	119	(10)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	4	MWh	@	0.026704	0	0.031271	0	0
18	High-peak kWh	93	MWh	@	0.017803	2	0.020847	2	0
19	Mid-peak kWh	119	MWh	@	0.016483	2	0.019301	2	0
20	Off-peak kWh	3,871	MWh	@	0.013712	53	0.016057	62	9
21	Power Factor Adjustment					(1)		(1)	0
22	Interruptible Credit	6,737	MWh	@	(0.008461)	(57)	(0.008461)	(57)	-
23	Annual PSCR Factor	6,737	MWh	@	0.009410	63	0.009410	63	-
24	Total Production					$ 368		$ 366	$ (3)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	1	MWh	@	0.042822	$ 0	0.042796	$ 0	$ (0)
26	High-peak kWh	66	MWh	@	0.028548	2	0.028531	2	(0)
27	Mid-peak kWh	104	MWh	@	0.025418	3	0.025402	3	(0)
28	Low-peak kWh	1,569	MWh	@	0.020484	32	0.020472	32	(0)
29	Off-peak kWh	908	MWh	@	0.015321	14	0.015312	14	(0)
	Winter (Oct. - May)								
30	Critical-peak kWh	4	MWh	@	0.027586	0	0.027570	0	(0)
31	High-peak kWh	93	MWh	@	0.018391	2	0.018380	2	(0)
32	Mid-peak kWh	119	MWh	@	0.017027	2	0.017017	2	(0)
33	Off-peak kWh	3,871	MWh	@	0.014165	55	0.014156	55	(0)
34	Total Transmission					$ 109		$ 109	$ (0)
	Delivery								
35	System Access	54	Bills	@	200.00	$ 11	200.00	$ 11	$ -
36	Maximum kW	40	MW	@	6.68	267	6.67	266	(0)
37	Power Factor Adjustment					(1)		(1)	0
38	Distribution	6,737	MWh	@	-	-	-	-	-
39	Total Delivery					$ 277		$ 276	$ (0)
40	Total Full Service					$ 754		$ 751	$ (3)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Metered Lighting (GML)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
1	Secondary All kWh	10,328	MWh	@	0.034716	$ 359	0.034459	$ 356	$ (3)
2	Primary All kWh	448	MWh	@	0.017037	8	0.016911	8	(0)
3	Annual PSCR Factor	10,776	MWh	@	0.009410	101	0.009410	101	-
4	Total Production					$ 468		$ 465	$ (3)
	Transmission								
5	Secondary All kWh	10,328	MWh	@	0.010556	109	0.010549	109	(0)
6	Primary All kWh	448	MWh	@	0.005180	2	0.005177	2	(0)
7	Total Transmission	10,776				111		111	(0)
	Delivery								
	Secondary								
8	System Access	4,489	Bills	@	10.00	$ 45	10.00	$ 45	$ -
9	Distribution	10,328	MWh	@	0.118564	1,225	0.118515	1,224	(1)
	Primary								
10	System Access	297	Bills	@	20.00	$ 6	20.00	$ 6	$ -
11	Distribution	448	MWh	@	0.090355	41	0.090318	40	(0)
12	Total Delivery					$ 1,316		$ 1,315	$ (1)
13	Total Full Service					$ 1,895		$ 1,891	$ (3)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Universal Unmetered Light (UUL)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line		Billing Determinants							Present					Proposed					Net Increase
						Customer	Company		Customer Owned		Company Owned			Customer Owned		Company Owned			
No.	Description	Customer	Company	Units	Watts	MWh	MWh		Production	Delivery	Production	Delivery	Revenue	Production	Delivery	Production	Delivery	Revenue	/ (Decrease)
									$/Light	$/Light	$/Light	$/Light	$000	$/Light	$/Light	$/Light	$/Light	$000	$000
1	15 - 24 Watts	12	-	Lights	20	0	-	@	0.28	7.29	0.28	10.29	$ 0	0.28	7.29	0.28	10.29	$ 0	$ -
2	25 - 34 Watts	-	64,500	Lights	30	-	666	@	0.43	8.07	0.43	11.07	742	0.42	8.07	0.42	11.07	741	(1)
3	35 - 44 Watts	1,524	412,356	Lights	40	21	5,701	@	0.57	8.85	0.57	11.85	5,136	0.57	8.85	0.57	11.85	5,136	-
4	45 - 54 Watts	1,308	865,773	Lights	50	23	15,000	@	0.72	9.63	0.72	12.63	11,572	0.71	9.63	0.71	12.63	11,563	(9)
5	55 - 64 Watts	1,092	7,056	Lights	60	23	147	@	0.86	10.41	0.86	13.41	113	0.86	10.41	0.86	13.41	113	-
6	65 - 74 Watts	312	129,516	Lights	70	8	3,150	@	1.01	11.19	1.01	14.19	1,972	1.00	11.19	1.00	14.19	1,971	(1)
7	75 - 84 Watts	72	34,020	Lights	80	2	947	@	1.15	11.97	1.15	14.97	549	1.14	11.97	1.14	14.97	549	(0)
8	85 - 94 Watts	-	98,178	Lights	90	-	3,075	@	1.29	12.75	1.29	15.75	1,673	1.29	12.75	1.29	15.75	1,673	-
9	95 - 104 Watts	-	180	Lights	100	-	6	@	1.44	13.53	1.44	16.53	3	1.43	13.53	1.43	16.53	3	(0)
10	105 - 114 Watts	-	7,044	Lights	110	-	270	@	1.58	14.31	1.58	17.31	133	1.57	14.30	1.57	17.30	133	(0)
11	115 - 124 Watts	804	364,751	Lights	120	34	15,256	@	1.73	15.09	1.73	18.09	7,243	1.72	15.08	1.72	18.08	7,236	(7)
12	125 - 134 Watts	-	320	Lights	130	-	15	@	1.87	15.86	1.87	18.86	7	1.86	15.86	1.86	18.86	7	(0)
13	135 - 144 Watts	-	924	Lights	140	-	45	@	2.02	16.64	2.02	19.64	20	2.01	16.64	2.01	19.64	20	(0)
14	145 - 154 Watts	-	3,996	Lights	150	-	209	@	2.16	17.42	2.16	20.42	90	2.15	17.42	2.15	20.42	90	(0)
15	155 - 164 Watts	-	52	Lights	160	-	3	@	2.31	18.20	2.31	21.20	1	2.29	18.20	2.29	21.20	1	(0)
16	165 - 174 Watts	1,404	51,182	Lights	170	83	3,036	@	2.45	18.98	2.45	21.98	1,280	2.44	18.98	2.44	21.98	1,280	(1)
17	175 - 184 Watts	-	-	Lights	180	-	-	@	2.60	19.76	2.60	22.76	-	2.58	19.76	2.58	22.76	-	-
18	185 - 194 Watts	-	156	Lights	190	-	10	@	2.74	20.54	2.74	23.54	4	2.72	20.54	2.72	23.54	4	(0)
19	195 - 204 Watts	-	60	Lights	200	-	4	@	2.89	21.32	2.89	24.32	2	2.87	21.32	2.87	24.32	2	(0)
20	205 - 214 Watts	504	12,740	Lights	210	37	934	@	3.03	22.10	3.03	25.10	371	3.01	22.10	3.01	25.10	371	(0)
21	215 - 224 Watts	-	28	Lights	220	-	2	@	3.17	22.88	3.17	25.88	1	3.15	22.88	3.15	25.88	1	(0)
22	225 - 234 Watts	-	-	Lights	230	-	-	@	3.32	23.66	3.32	26.66	-	3.30	23.66	3.30	26.66	-	-
23	235 - 244 Watts	-	-	Lights	240	-	-	@	3.46	24.44	3.46	27.44	-	3.44	24.44	3.44	27.44	-	-
24	245 - 254 Watts	60	432	Lights	250	5	38	@	3.61	25.22	3.61	28.22	15	3.59	25.22	3.59	28.22	15	(0)
25	255 - 264 Watts	-	-	Lights	260	-	-	@	3.75	26.00	3.75	29.00	-	3.73	26.00	3.73	29.00	-	-
26	265 - 274 Watts	-	-	Lights	270	-	-	@	3.90	26.78	3.90	29.78	-	3.87	26.78	3.87	29.78	-	-
27	275 - 284 Watts	396	3,949	Lights	280	39	386	@	4.04	27.56	4.04	30.56	149	4.02	27.55	4.02	30.55	149	(0)
28	285 - 294 Watts	12	1,292	Lights	290	1	131	@	4.19	28.34	4.19	31.34	46	4.16	28.33	4.16	31.33	46	(0)
29	295 - 304 Watts	-	-	Lights	300	-	-	@	4.33	29.12	4.33	32.12	-	4.30	29.11	4.30	32.11	-	-
30	305 - 314 Watts	108	-	Lights	310	12	-	@	4.48	29.90	4.48	32.90	4	4.45	29.89	4.45	32.89	4	(0)
31	315 - 324 Watts	540	29,081	Lights	320	60	3,252	@	4.62	30.68	4.62	33.68	1,133	4.59	30.67	4.59	33.67	1,132	(1)
32	325 - 334 Watts	-	-	Lights	330	-	-	@	4.77	31.45	4.77	34.45	-	4.74	31.45	4.74	34.45	-	-
33	335 - 344 Watts	-	-	Lights	340	-	-	@	4.91	32.23	4.91	35.23	-	4.88	32.23	4.88	35.23	-	-
34	345 - 354 Watts	-	-	Lights	350	-	-	@	5.05	33.01	5.05	36.01	-	5.02	33.01	5.02	36.01	-	-
35	355 - 364 Watts	-	-	Lights	360	-	-	@	5.20	33.79	5.20	36.79	-	5.17	33.79	5.17	36.79	-	-
36	365 - 374 Watts	-	-	Lights	370	-	-	@	5.34	34.57	5.34	37.57	-	5.31	34.57	5.31	37.57	-	-
37	375 - 384 Watts	-	-	Lights	380	-	-	@	5.49	35.35	5.49	38.35	-	5.45	35.35	5.45	38.35	-	-
38	385 - 394 Watts	-	-	Lights	390	-	-	@	5.63	36.13	5.63	39.13	-	5.60	36.13	5.60	39.13	-	-
39	395 - 404 Watts	-	12	Lights	400	-	2	@	5.78	36.91	5.78	39.91	1	5.74	36.91	5.74	39.91	1	(0)
40	405 - 414 Watts	24	24	Lights	410	3	3	@	5.92	37.69	5.92	40.69	2	5.89	37.69	5.89	40.69	2	(0)
41	415 - 424 Watts	-	-	Lights	420	-	-	@	6.07	38.47	6.07	41.47	-	6.03	38.47	6.03	41.47	-	-
42	425 - 434 Watts	-	-	Lights	430	-	-	@	6.21	39.25	6.21	42.25	-	6.17	39.25	6.17	42.25	-	-
43	435 - 444 Watts	-	-	Lights	440	-	-	@	6.36	40.03	6.36	43.03	-	6.32	40.02	6.32	43.02	-	-
44	445 - 454 Watts	-	-	Lights	450	-	-	@	6.50	40.81	6.50	43.81	-	6.46	40.80	6.46	43.80	-	-
45	455 - 464 Watts	888	1,460	Lights	460	143	235	@	6.65	41.59	6.65	44.59	118	6.60	41.58	6.60	44.58	118	(0)
46	465 - 474 Watts	-	-	Lights	470	-	-	@	6.79	42.37	6.79	45.37	-	6.75	42.36	6.75	45.36	-	-
47	475 - 484 Watts	180	9,489	Lights	480	30	1,593	@	6.94	43.15	6.94	46.15	513	6.89	43.14	6.89	46.14	512	(1)
48	Conversion Credit	-	129,840	Lights								(7.72)	(1,002)				(7.72)	(1,002)	-
49	Annual PSCR Factor	9,240	2,098,571	Lights		524	54,116		0.009410		0.009410		514	0.009410		0.009410		514	-
50	Total Unmetered LED	9,240	2,098,571	Lights		524	54,116						$ 32,405					$ 32,383	$ (21)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Unmetered Service (GU)

Case No.: U-22070
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Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
1	Non-capacity All kWh	99,352	MWh	@	0.037706	$ 3,746	0.034464	$ 3,424	$ (322)
2	Capacity All kWh	99,352	MWh	@	0.015927	1,582	0.018633	1,851	269
3	Annual PSCR Factor	99,352	MWh	@	0.009410	935	0.009410	935	-
4	Total Production					$ 6,264		$ 6,210	$ (53)
	Transmission								
5	All kWh	99,352	MWh	@	0.015085	1,499	0.015076	1,498	(1)
	Delivery								
6	System Access	5,578	Bills	@	2.00	$ 11	2.00	$ 11	$ -
7	Distribution	99,352	MWh	@	0.034452	3,423	0.034405	3,418	(5)
8	Total Delivery					$ 3,434		$ 3,429	$ (5)
9	Total Full Service					$ 11,196		$ 11,137	$ (59)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Large Self-generation (GSG-2)

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	STANDBY SERVICE								
	Production								
	Voltage Level 1								
1	On-peak kW-day	108	MW	@	11.57	$ 1,254	11.57	$ 1,254	$ -
2	All kWh	77,349	MWh	@	0.046132	3,568	0.046132	3,568	-
	Voltage Level 2								
3	On-peak kW-day	223	MW	@	11.73	2,613	11.73	2,613	-
4	All kWh	77,337	MWh	@	0.048126	3,722	0.048126	3,722	-
	Voltage Level 3								
5	On-peak kW-day	55	MW	@	11.91	650	11.91	650	-
6	All kWh	18,615	MWh	@	0.047120	877	0.047120	877	-
7	Power Factor Adjustment					261		261	-
8	Total Production					$ 12,946		$ 12,946	$ -
	Transmission								
	Voltage Level 1								
9	On-peak kW-day	108	MW	@	3.05	$ 330	3.05	$ 330	$ -
	Voltage Level 2								
10	On-peak kW-day	223	MW	@	3.09	688	3.09	688	-
	Voltage Level 3								
11	On-peak kW-day	55	MW	@	3.14	171	3.14	171	-
12	Total Transmission					$ 1,190		$ 1,190	$ -
	Delivery								
	System Access								
	Voltage Level 1								
13	Standby	64	Bills	@	100.00	$ 6	100.00	$ 6	$ -
14	Supplemental	-	Bills	@	100.00	-	100.00	-	-
15	Maximum kW	889	MW	@	2.37	2,110	2.36	2,099	(11)
16	Interconnect	355	MW	@	(2.37)	(842)	(2.36)	(838)	4
17	Substation Ownership	-	MW	@	(1.82)	-	(1.82)	-	-
	Voltage Level 2								
18	Standby	94	Bills	@	100.00	$ 9	100.00	$ 9	$ -
19	Supplemental	-	Bills	@	100.00	-	100.00	-	-
20	Maximum kW	610	MW	@	3.61	2,203	3.60	2,196	(7)
21	Substation Ownership	288	MW	@	(1.93)	(555)	(1.93)	(555)	-
	Voltage Level 3								
22	Standby	13	Bills	@	100.00	$ 1	100.00	$ 1	$ -
23	Supplemental	-	Bills	@	100.00	-	100.00	-	-
24	Maximum kW	62	MW	@	6.68	412	6.67	412	(0)
25	Power Factor Adjustment					63		63	(0)
26	Total Delivery					$ 3,408		$ 3,394	$ (14)
27	Total Standby Service					$ 17,543		$ 17,529	$ (14)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response (DR) Surcharge

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Program plus Cust. Credits [1]	(c) Financial Incentive [1]	(d) Reconciled Balance [1]	(e) Total	(f) Units
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	0.001707	-	-	0.001707	per kWh
2	Smart Hours RSH	0.001707	-	-	0.001707	per kWh
3	Night Time Savers RPM	0.001707	-	-	0.001707	per kWh
4	Non-Transmitting Meters RSM	0.001707	-	-	0.001707	per kWh
	Secondary Class					
5	Energy-only GS	0.001552	-	-	0.001552	per kWh
6	Time-of-Use GSTU	0.001552	-	-	0.001552	per kWh
7	Demand GSD	0.52	-	-	0.52	per Peak kW
	Primary Class					
	Energy-only GP					
8	Voltage Level 1	0.001313	-	-	0.001313	per kWh
9	Voltage Level 2	0.001328	-	-	0.001328	per kWh
10	Voltage Level 3	0.001342	-	-	0.001342	per kWh
	Demand GPD					
11	Voltage Level 1	0.57	-	-	0.57	per On-Peak kW
12	Voltage Level 2	0.58	-	-	0.58	per On-Peak kW
13	Voltage Level 3	0.58	-	-	0.58	per On-Peak kW
14	Large Load	0.69	-	-	0.69	per On-Peak kW
	Time-of-Use GPTU					
15	Voltage Level 1	0.001188	-	-	0.001188	per kWh
16	Voltage Level 2	0.001202	-	-	0.001202	per kWh
17	Voltage Level 3	0.001214	-	-	0.001214	per kWh
	Energy Intensive EIP					
18	Voltage Level 1	0.000959	-	-	0.000959	per kWh
19	Voltage Level 2	0.000970	-	-	0.000970	per kWh
20	Voltage Level 3	0.000980	-	-	0.000980	per kWh
	Lighting & Unmetered Class					
21	Metered Lighting GML	0.000372	-	-	0.000372	per kWh
22	Universal Unmetered Lighting UUL	0.000347	-	-	0.000347	per kWh
23	Unmetered GU	0.001011	-	-	0.001011	per kWh
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	NA	NA	NA	NA	
25	Demand GSD	NA	NA	NA	NA	
	Primary Class					
	Energy-only GP					
26	Voltage Level 1	NA	NA	NA	NA	
27	Voltage Level 2	NA	NA	NA	NA	
28	Voltage Level 3	NA	NA	NA	NA	
	Demand GPD					
29	Voltage Level 1	NA	NA	NA	NA	
30	Voltage Level 2	NA	NA	NA	NA	
31	Voltage Level 3	NA	NA	NA	NA	

(1) WP-LMC-19

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Rate Case (ERC) Deferral Surcharge

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) ERC Deferral [1] ($000)	(d) ERC Deferral Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 15,476	0.001220
	Secondary Class			
2	Energy-only GS	4,114,839	3,835	0.000932
3	Time-of-Use GSTU	84,563	79	0.000932
4	Demand GSD	2,979,606	2,145	0.000720
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	0	0.000115
6	Voltage Level 2	31,259	6	0.000177
7	Voltage Level 3	632,239	192	0.000304
	Demand GPD			
8	Voltage Level 1	1,167,540	69	0.000059
9	Voltage Level 2	1,453,040	132	0.000091
10	Voltage Level 3	2,414,780	377	0.000156
11	Large Load	7,884,000	465	0.000059
	Time-of-Use GPTU			
12	Voltage Level 1	464,518	27	0.000059
13	Voltage Level 2	496,642	45	0.000091
14	Voltage Level 3	3,312,240	517	0.000156
	Energy Intensive EIP			
15	Voltage Level 1	332,592	20	0.000059
16	Voltage Level 2	53,237	5	0.000091
17	Voltage Level 3	6,737	1	0.000156
	Lighting & Unmetered Class			
18	Metered Lighting GML	10,776	15	0.001408
19	Universal Unmetered Lighting UUL	54,640	342	0.006253
20	Unmetered GU	99,352	40	0.000401
	Self-generation Class			
21	Large Self-generation GSG-2			
22	Voltage Level 1	77,349	5	0.000059
23	Voltage Level 2	77,337	7	0.000091
24	Voltage Level 3	18,615	3	0.000156
25	Total Full Service		$ 23,802	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) ERC Deferral [1] ($000)	(h) ERC Deferral Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001220
	Secondary Class			
2	Energy-only GS	18,702	17	0.000932
3	Time-of-Use GSTU	-	-	0.000932
4	Demand GSD	174,288	125	0.000720
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000115
6	Voltage Level 2	1,783	0	0.000177
7	Voltage Level 3	70,285	21	0.000304
	Demand GPD			
8	Voltage Level 1	1,270,576	75	0.000059
9	Voltage Level 2	1,080,207	98	0.000091
10	Voltage Level 3	953,091	149	0.000156
11	Total ROA Service		$ 487	
12	Total Surcharge Revenue Collected		$ 24,289	
13	Rounding		20	
14	Total Surcharge Revenue Target		$ 24,309	

(1) A-89 (EAD-5), line 12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 1 - 12 months ending April 30, 2027

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
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Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue [1] ($000)	(d) IRM Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 8,867	0.000699
	Secondary Class			
2	Energy-only GS	4,114,839	2,197	0.000534
3	Time-of-Use GSTU	84,563	45	0.000534
4	Demand GSD	2,979,606	1,228	0.000412
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	0	0.000072
6	Voltage Level 2	31,259	3	0.000101
7	Voltage Level 3	632,239	110	0.000174
	Demand GPD			
8	Voltage Level 1	1,167,540	42	0.000036
9	Voltage Level 2	1,453,040	74	0.000051
10	Voltage Level 3	2,414,780	210	0.000087
11	Large Load	7,884,000	284	0.000036
	Time-of-Use GPTU			
12	Voltage Level 1	464,518	17	0.000036
13	Voltage Level 2	496,642	25	0.000051
14	Voltage Level 3	3,312,240	288	0.000087
	Energy Intensive EIP			
15	Voltage Level 1	332,592	12	0.000036
16	Voltage Level 2	53,237	3	0.000051
17	Voltage Level 3	6,737	1	0.000087
	Lighting & Unmetered Class			
18	Metered Lighting GML	10,776	9	0.000806
19	Universal Unmetered Lighting UUL	54,640	196	0.003580
20	Unmetered GU	99,352	23	0.000230
	Self-generation Class			
21	Large Self-generation GSG-2			
22	Voltage Level 1	77,349	3	0.000036
23	Voltage Level 2	77,337	4	0.000051
24	Voltage Level 3	18,615	2	0.000087
25	Total Full Service		$ 13,642	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue [1] ($000)	(h) IRM Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.000699
	Secondary Class			
2	Energy-only GS	18,702	10	0.000534
3	Time-of-Use GSTU	-	-	0.000534
4	Demand GSD	174,288	72	0.000412
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000072
6	Voltage Level 2	1,783	0	0.000101
7	Voltage Level 3	70,285	12	0.000174
	Demand GPD			
8	Voltage Level 1	1,270,576	46	0.000036
9	Voltage Level 2	1,080,207	55	0.000051
10	Voltage Level 3	953,091	83	0.000087
11	Total ROA Service		$ 278	
12	Total Surcharge Revenue Collected		$ 13,920	
13	Rounding		7	
14	Total Surcharge Revenue Target		$ 13,927	

(1) A-89 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 2 - 12 months ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-69 (LMC-6)
Page: 32 of 32
Witness: LMConnolly
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue [1] ($000)	(d) IRM Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 16,288	0.001284
	Secondary Class			
2	Energy-only GS	4,114,839	4,037	0.000981
3	Time-of-Use GSTU	84,563	83	0.000981
4	Demand GSD	2,979,606	2,256	0.000757
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,454	0	0.000133
6	Voltage Level 2	31,259	10	0.000321
7	Voltage Level 3	632,239	203	0.000321
	Demand GPD			
8	Voltage Level 1	1,167,540	71	0.000061
9	Voltage Level 2	1,453,040	214	0.000147
10	Voltage Level 3	2,414,780	355	0.000147
11	Large Load	7,884,000	481	0.000061
	Time-of-Use GPTU			
12	Voltage Level 1	464,518	28	0.000061
13	Voltage Level 2	496,642	73	0.000147
14	Voltage Level 3	3,312,240	487	0.000147
	Energy Intensive EIP			
15	Voltage Level 1	332,592	20	0.000061
16	Voltage Level 2	53,237	8	0.000147
17	Voltage Level 3	6,737	1	0.000147
	Lighting & Unmetered Class			
18	Metered Lighting GML	10,776	16	0.001481
19	Universal Unmetered Lighting UUL	54,640	359	0.006579
20	Unmetered GU	99,352	42	0.000422
	Self-generation Class			
21	Large Self-generation GSG-2			
22	Voltage Level 1	77,349	5	0.000061
23	Voltage Level 2	77,337	11	0.000147
24	Voltage Level 3	18,615	3	0.000147
25	Total Full Service		$ 25,051	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue [1] ($000)	(h) IRM Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001284
	Secondary Class			
2	Energy-only GS	18,702	18	0.000981
3	Time-of-Use GSTU	-	-	0.000981
4	Demand GSD	174,288	132	0.000757
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000133
6	Voltage Level 2	1,783	1	0.000321
7	Voltage Level 3	70,285	23	0.000321
	Demand GPD			
8	Voltage Level 1	1,270,576	78	0.000061
9	Voltage Level 2	1,080,207	159	0.000147
10	Voltage Level 3	953,091	140	0.000147
11	Total ROA Service		$ 550	
12	Total Surcharge Revenue Collected		$ 25,601	
13	Rounding		(4)	
14	Total Surcharge Revenue Target		$ 25,597	

(1) A-89 (EAD-5)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

AMY M. CONRAD

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

OFFICER PLAN

Category	2025 MEASURE	Weighting
Safety	**Employee Safety** (Recordable Incident Rate (70% weighting) & High-Risk Injuries (30% weighting) and Zero fatalities)	**5%**
People	**Culture Index** (Employee Empowerment, Employee Engagement and DEI)	**5%**
Customer	**Customer Experience** - CXi (Survey measuring Customer Experience)	**5%**
Reliability	**Electric Reliability** - SAIDI (System Average Interruption Duration Index)	**5%**
Price	**Affordability** (O&M Savings through Waste Elimination)	**5%**
Environmental	**Methane Emission Reduction** (Reduction of Methane Emissions through replacements of Mains and Services, and through implantation of gas venting protocols)	**5%**
	Total Operational Goals	**30%**
Financial	**Earnings** (Earnings Per Share)	**70%**
	Total Financial Goals	**70%**

NON-OFFICER PLAN

Category	2025 MEASURE	Weighting
Safety	**Employee Safety** (Recordable Incident Rate (70% weighting) & High-Risk Injuries (30% weighting) and Zero fatalities)	**8.3%**
People	**Culture Index** (Employee Empowerment, Employee Engagement and DEI)	**8.3%**
Customer	**Customer Experience** - CXi (Survey measuring Customer Experience)	**8.3%**
Reliability	**Electric Reliability** - SAIDI (System Average Interruption Duration Index)	**8.3%**
Price	**Waste Elimination** (O&M Savings through Waste Elimination)	**8.3%**
Environmental	**Methane Emission Reduction** (Reduction of Methane Emissions through replacements of Mains and Services, and through implantation of gas venting protocols)	**8.3%**
	Total Operational Goals	**50%**
Financial	**Earnings** (Earnings Per Share)	**50%**
	Total Financial Goals	**50%**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
EICP Operational Performance Measures

Case No.: U-22070
Exhibit No.: A-70 (AMC-1)
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Witness: AMConrad
Date: June 2026

2025 Plan Year

Metric	50% Threshold	75%	100% Target	125%	150%	175% Max
Employee Safety						
a. Recordable Incidents Rate (30%),	a.1.24	a.1.12	**a.1.00**	a.0.98	a.0.96	a.0.94
b. High-Risk Injuries[1] (70%),	b.20	b.16	**b.12**	b.11	b.10	b.9
c. No fatalities[2]						
Culture Index						
a. Employee Engagement (33%),	a.71	a.72	**a.**73	a.74	a.76	a.78
b. Empowerment (33%), &	b.65	b.66	**b.**67	b.68	b.70	b.72
c. Diversity, Equity, & Inclusion (33%)	c.73	c.74	**c.**75	c.76	c.78	c.80
(Overall outcome = avg of each index award)						
Customer Experience [1] (Survey Measuring CXi)	**64**	**65**	**66**	**68**	**70**	**75**
Electric Reliability (SAIDI)	165 mins	160 mins	155 mins	150 mins	145 mins	140 mins
Waste Elimination[3] (O&M Savings through Waste Elimination)	$44M	$49M	$53M	$58M	$66M	$75M
Methane Emission Reduction (Reduce fugitive methane emissions associated with gas distribution)	74 MT	78 MT	82 MT	93 MT	114 MT	135 MT

1 High-Risk = Recordable or non-recordable injury caused by a release of high energy
2 A fatality = zero payout for employee safety
3 The Company is not seeking recovery of this measure as it is financial in nature.

OFFICER PLAN

Category	2026 MEASURE	Weighting
Safety	**Employee Safety** (Serious Injury Incident Rate (80% weighting) & Recordable Incident Rate (20% weighting) and Zero fatalities)	**5.0%**
People	**Culture Index** (Employee Empowerment, Employee Engagement and DEI)	**5.0%**
Customer	**Customer Experience** - CXi (Survey measuring Customer Experience)	**5.0%**
Reliability	**Electric Reliability** - SAIDI (System Average Interruption Duration Index)	**5.0%**
Price	**Affordability** (O&M Savings through Waste Elimination)	**5.0%**
Environmental	**Methane Emission Reduction** (Reduction of Methane Emissions through replacements of Mains and Services, and through implantation of gas venting protocols)	**5.0%**
	Total Operational Goals	**30%**
Financial	**Earnings** (Earnings Per Share)	**70%**
	Total Financial Goals	**70%**

NON-OFFICER PLAN

Category	2024 MEASURE	Weighting
Safety	**Employee Safety** (Recordable Incident Rate & High-Risk Injuries (equally weighted) and Zero fatalities)	**8.3%**
People	**Culture Index** (Employee Empowerment, Employee Engagement and DEI)	**8.3%**
Customer	**Customer Experience** - CXi (Survey measuring Customer Experience)	**8.3%**
Reliability	**Electric Reliability** - SAIDI (System Average Interruption Duration Index)	**8.3%**
Price	**Affordability** (O&M Savings through Waste Elimination)	**8.3%**
Environmental	**Methane Emission Reduction** (Reduction of Methane Emissions through replacements of Mains and Services, and through implantation of gas venting protocols)	**8.3%**
	Total Operational Goals	**50%**
Financial	**Earnings** (Earnings Per Share)	**50%**
	Total Financial Goals	**50%**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
EICP Operational Performance Measures

Case No.: U-22070
Exhibit No.: A-70 (AMC-1)
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Witness: AMConrad
Date: June 2026

2026 Plan Year

Metric	50% Min	75%	100%	125%	150%	175% Max
Employee Safety	a. 0.061	a. 0.049	**a. 0.037**	a. 0.025	a. 0.012	a.0
a. Serious Injury Incident Rate (80%)	b.1.48	b.1.36	**b.1.24**	b.1.13	b.1.01	b.0.53
b. Recordable Incident Rate (20%)	c. 0	c. 0	**c. 0**	c. 0	c. 0	c. 0
c. No Fatalities						
Culture Index	a.76	a.77	**a.78**	a.79	a.80	a.81
a.Employee Engagement (33%)	b.67	b.68	**b.69**	b.70	b.71	b.72
b.Empowerment (33%)	c.76	c.77	**c.78**	c.79	c.80	c. 81
c.Diversity, Equity, & Inclusion (33%)						
Customer Experience	61	62	**64**	65	67	69
Survey Measuring CXi						
Electric Reliability	160 mins	155 mins	**150 mins**	145 mins	140 mins	130 mins
SAIDI – excluding MEDs						
Waste Elimination[1]	$30M	$35M	**$40M**	$45M	$50M	$55M
O&M Savings through Waste Elimination						
Methane Emissions Reduction	84 MT	88 MT	**93 MT**	101 MT	121 MT	147 MT
Reduce fugitive methane emissions associated with gas distribution						

1 The Company is not seeking recovery of this measure as it is financial in nature.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Target Pay Level Market Analysis
Non-officer _ Salary

Case No.: U-22070
Exhibit No.: A-71 (AMC-2)
Page: 1 of 2
Witness: AMConrad
Date: June 2026

Exempt Jobs:
2025 Market study

Job Family	# of Employees	Annual Salary	Market Data	Avg. Salary vs Market
ACCOUNTING	61	$ 119,488.33	$ 118,305.38	1.0%
ACCOUNTS PAYABLE & RECEIVABLE	6	$ 99,404.00	$ 102,498.83	-3.0%
ADMINISTRATIVE SUPPORT	26	$ 88,085.08	$ 87,175.85	1.0%
ANALYTICS	75	$ 116,924.48	$ 126,868.12	-7.8%
ASSET PROCUREMENT	4	$ 148,578.00	$ 134,893.00	10.1%
BENEFITS	13	$ 124,492.62	$ 113,513.31	9.7%
BUSINESS DEVELOPMENT	33	$ 169,884.36	$ 169,944.30	0.0%
BUSINESS PROCESS & SERVICE QUALITY	68	$ 113,983.59	$ 109,383.01	4.2%
BUSINESS QUALITY MANAGEMENT	31	$ 146,997.97	$ 138,255.52	6.3%
BUSINESS STRATEGY & PLANNING	122	$ 145,414.72	$ 146,705.35	-0.9%
BUSINESS SYSTEMS ANALYSIS	33	$ 115,347.85	$ 115,382.03	0.0%
CAPITAL MARKETS	5	$ 196,886.40	$ 204,641.20	-3.8%
CHEMICAL	2	$ 163,836.00	$ 147,405.00	11.1%
CIVIL	42	$ 114,266.24	$ 113,183.10	1.0%
COMMUNICATIONS	23	$ 119,833.57	$ 115,681.30	3.6%
COMPENSATION	8	$ 150,660.00	$ 140,967.25	6.9%
CONSTRUCTION PROJECT MANAGEMENT	94	$ 160,833.17	$ 150,786.90	6.7%
CORPORATE AFFAIRS	31	$ 139,599.48	$ 133,253.52	4.8%
CORPORATE GOVERNANCE	2	$ 173,772.00	$ 189,763.00	-8.4%
CO-WORKER CONNECTIONS	11	$ 157,805.45	$ 155,849.73	1.3%
CREDIT & COLLECTIONS	1	$ 122,760.00	$ 109,538.00	12.1%
CUSTOMER SERVICE	45	$ 102,657.60	$ 96,406.87	6.5%
CYBER SECURITY	106	$ 143,607.51	$ 140,557.00	2.2%
DATA SCIENCE	39	$ 138,441.23	$ 139,160.87	-0.5%
DATABASE ADMINISTRATION	3	$ 128,928.00	$ 137,494.00	-6.2%
DESIGN SERVICES	2	$ 119,120.00	$ 121,770.00	-2.2%
DIVERSITY EQUITY & INCLUSION	5	$ 139,190.40	$ 143,522.80	-3.0%
DOCUMENTATION & RECORD KEEPING	7	$ 94,522.29	$ 101,492.14	-6.9%
ELECTRICAL	193	$ 126,801.14	$ 129,422.44	-2.0%
EMPLOYEE RELATIONS	19	$ 145,173.47	$ 138,532.60	4.8%
ENGINEERING & TECHNICAL LEADERSHIP	184	$ 164,595.98	$ 171,239.88	-3.9%
ENVIRONMENTAL & EMPLOYEE HEALTH & SAFETY	66	$ 132,259.09	$ 132,996.49	-0.6%
ETHICS & COMPLIANCE	39	$ 126,581.54	$ 114,867.83	10.2%
EXPLORATION & PRODUCTION OPERATIONS	86	$ 143,082.98	$ 136,223.62	5.0%
FACILITIES MANAGEMENT & PLANNING	8	$ 129,069.00	$ 118,171.88	9.2%
FINANCIAL CONTROL	14	$ 132,007.71	$ 123,597.64	6.8%
FINANCIAL FORECASTING	80	$ 137,500.20	$ 127,909.75	7.5%
HR TECHNOLOGY	5	$ 122,800.80	$ 123,608.20	-0.7%
INDUSTRIAL	16	$ 130,647.75	$ 126,555.31	3.2%
INFORMATION & TECHNOLOGY LEADERSHIP	55	$ 189,339.71	$ 190,219.38	-0.5%
INFORMATION & TECHNOLOGY MANAGEMENT	41	$ 140,141.85	$ 135,864.37	3.1%
INTERNAL AUDIT	9	$ 153,709.33	$ 146,168.22	5.2%
INVESTOR RELATIONS	3	$ 149,224.00	$ 143,514.33	4.0%
LABOR RELATIONS	9	$ 116,993.33	$ 122,363.56	-4.4%
LABORATORY SERVICES	26	$ 117,557.08	$ 115,921.62	1.4%
LEARNING & DEVELOPMENT	66	$ 111,349.09	$ 110,567.98	0.7%
LEGAL PROFESSIONALS	27	$ 189,628.44	$ 202,300.07	-6.3%
MACHINE OPERATIONS	6	$ 146,252.00	$ 138,555.83	5.6%
MANUFACTURING PLANT MANAGEMENT	5	$ 179,102.40	$ 163,337.00	9.7%
MARKETING GENERALISTS	37	$ 122,402.27	$ 117,806.11	3.9%
MECHANICAL	102	$ 130,052.24	$ 132,005.25	-1.5%
ORGANIZATIONAL DEVELOPMENT	12	$ 124,830.00	$ 125,336.67	-0.4%
PAYROLL	4	$ 108,828.00	$ 99,783.50	9.1%
PHYSICAL SECURITY	8	$ 128,047.50	$ 145,665.00	-12.1%
POWER GEN TRANSMISSION & DISTRIBUTION	336	$ 127,603.28	$ 125,968.82	1.3%
PROCUREMENT	43	$ 110,396.09	$ 112,323.70	-1.7%
PROGRAM MANAGEMENT	35	$ 140,419.89	$ 140,836.69	-0.3%
PROJECT & PROGRAM MANAGEMENT	73	$ 134,536.77	$ 133,656.66	0.7%
PROPERTY MANAGEMENT	3	$ 98,712.00	$ 122,477.33	-19.4%
RATES & REGULATION	16	$ 152,610.00	$ 154,942.25	-1.5%
REAL ESTATE MANAGEMENT	28	$ 120,006.00	$ 129,876.96	-7.6%
REGULATORY AFFAIRS	6	$ 156,356.00	$ 155,192.83	0.7%
RELATIONSHIP MANAGEMENT	34	$ 142,653.18	$ 137,001.76	4.1%
REPAIR & MAINTENANCE TRADES	19	$ 146,355.79	$ 137,678.58	6.3%
RISK MANAGEMENT	18	$ 142,106.00	$ 139,841.83	1.6%
SALES & MARKETING	42	$ 153,937.52	$ 149,393.45	3.0%
SOFTWARE DEVELOPMENT	11	$ 116,967.27	$ 124,063.45	-5.7%
SOFTWARE PRODUCT ENGINEERING	193	$ 133,972.85	$ 138,982.91	-3.6%
SUPPLY CHAIN PLANNING & OPERATIONS	42	$ 126,336.86	$ 110,835.02	14.0%
SYSTEMS ADMINISTRATION & REPORTING	3	$ 122,944.00	$ 116,918.00	5.2%
SYSTEMS ARCHITECTURE	25	$ 155,003.52	$ 148,752.64	4.2%
SYSTEMS OPS & PRODUCTION CONTROL	3	$ 140,192.00	$ 106,508.33	31.6%
TALENT ACQUISITION	10	$ 110,884.80	$ 103,972.70	6.6%
TAX	13	$ 147,223.38	$ 123,611.93	19.1%
TECHNICAL ANALYST	219	$ 113,057.15	$ 120,247.11	-6.0%
TECHNOLOGY SUPPORT	17	$ 111,753.88	$ 114,242.65	-2.2%
TELECOM & INTERNET	3	$ 110,928.00	$ 112,298.00	-1.2%
TREASURY	4	$ 141,294.00	$ 130,749.25	8.1%
UTILITIES OPERATIONS	361	$ 136,390.47	$ 132,379.40	3.0%
WAREHOUSING & DISTRIBUTION	18	$ 111,458.67	$ 101,464.21	9.9%
WORKFORCE ANALYTICS	4	$ 129,609.00	$ 114,455.00	13.2%
Grand Total	**3597**			**2.3%**

Non-Exempt:
2025 Market study

Job Family	# of Employees	Annual Salary	Market Data	Avg. Salary vs Market
ACCOUNTING	8	$ 73,660.63	$ 79,623.50	-7.5%
ACCOUNTS PAYABLE & RECEIVABLE	71	$ 66,303.63	$ 58,614.39	13.1%
ADMINISTRATIVE SUPPORT	36	$ 65,859.11	$ 57,313.97	14.9%
ASSET PROCUREMENT	1	$ 61,922.00	$ 65,221.00	-5.1%
BUSINESS PROCESS & SERVICE QUALITY	15	$ 75,591.33	$ 70,174.13	7.7%
CREDIT & COLLECTIONS	5	$ 62,445.80	$ 65,770.20	-5.1%
CUSTOMER SERVICE	19	$ 63,417.05	$ 67,268.16	-5.7%
CYBER SECURITY	18	$ 60,916.33	$ 68,449.56	-11.0%
DESIGN SERVICES	1	$ 123,947.00	$ 100,191.00	23.7%
DOCUMENTATION & RECORD KEEPING	13	$ 68,176.08	$ 59,000.31	15.6%
EMPLOYEE RELATIONS	5	$ 70,300.00	$ 68,332.20	2.9%
ENGINEERING TECHNOLOGISTS & TECHNICIANS	261	$ 85,939.72	$ 89,411.00	-3.9%
ENVIRONMENTAL & EMPLOYEE HEALTH & SAFETY	4	$ 66,248.00	$ 54,675.75	21.2%
ETHICS & COMPLIANCE	30	$ 69,204.43	$ 69,058.43	0.2%
FACILITIES MANAGEMENT & PLANNING	2	$ 53,040.00	$ 54,412.00	-2.5%
HEAVY EQUIPMENT & CONSTRUCTION TRADES	5	$ 68,061.80	$ 62,191.00	9.4%
LABORATORY SERVICES	32	$ 78,976.97	$ 86,185.31	-8.4%
LEGAL PROFESSIONALS	4	$ 94,083.50	$ 100,292.50	-6.2%
MACHINE OPERATIONS	74	$ 79,037.73	$ 83,080.51	-4.9%
PAYROLL	15	$ 64,195.73	$ 60,632.67	5.9%
POWER GEN TRANSMISSION & DISTRIBUTION	121	$ 75,015.28	$ 74,258.29	1.0%
PROCUREMENT	3	$ 63,523.33	$ 72,694.00	-12.6%
PROJECT & PROGRAM MANAGEMENT	150	$ 81,063.16	$ 65,611.01	23.6%
PROPERTY MANAGEMENT	6	$ 65,104.00	$ 68,762.83	-5.3%
REGULATORY AFFAIRS	17	$ 74,076.12	$ 75,127.82	-1.4%
REPAIR & MAINTENANCE TRADES	25	$ 86,935.64	$ 81,383.04	6.8%
UTILITIES OPERATIONS	33	$ 75,907.30	$ 67,328.03	12.7%
WAREHOUSING & DISTRIBUTION	5	$ 57,695.00	$ 58,879.40	-2.0%
Grand Total	**979**			**0.0%**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Target Pay Level Market Analysis
Non-officer _Total Target Cash

Case No.: U-22070
Exhibit No.: A-71 (AMC-2)
Page: 2 of 2
Witness: AMConrad
Date: June 2026

Exempt Jobs:
2025 Market study

Job Family	# of Employees	Average Total Cash Actual	Average Market Total Target Cash 50th	Average Total Cash to Average Market Total
ACCOUNTING	61	$ 122,686.69	$ 134,429.34	-8.7%
ACCOUNTS PAYABLE & RECEIVABLE	6	$ 102,404.00	$ 114,708.50	-10.7%
ADMINISTRATIVE SUPPORT	26	$ 89,162.00	$ 90,495.85	-1.5%
ANALYTICS	75	$ 119,539.15	$ 138,978.32	-14.0%
ASSET PROCUREMENT	4	$ 152,453.00	$ 149,653.50	1.9%
BENEFITS	13	$ 128,069.54	$ 126,115.15	1.5%
BUSINESS DEVELOPMENT	33	$ 176,005.58	$ 210,522.21	-16.4%
BUSINESS PROCESS & SERVICE QUALITY	68	$ 115,812.26	$ 119,358.03	-3.0%
BUSINESS QUALITY MANAGEMENT	31	$ 151,707.65	$ 154,016.45	-1.5%
BUSINESS STRATEGY & PLANNING	122	$ 149,477.02	$ 169,019.59	-11.6%
BUSINESS SYSTEMS ANALYSIS	33	$ 117,047.85	$ 124,996.70	-6.4%
CAPITAL MARKETS	5	$ 207,936.40	$ 264,323.00	-21.3%
CHEMICAL	2	$ 166,836.00	$ 153,275.00	8.8%
CIVIL	42	$ 116,242.43	$ 119,739.19	-2.9%
COMMUNICATIONS	23	$ 122,670.52	$ 126,925.35	-3.4%
COMPENSATION	8	$ 153,910.00	$ 156,801.75	-1.8%
CONSTRUCTION PROJECT MANAGEMENT	94	$ 163,905.51	$ 164,230.85	-0.2%
CORPORATE AFFAIRS	31	$ 143,801.10	$ 150,723.84	-4.6%
CORPORATE GOVERNANCE	2	$ 186,397.00	$ 231,010.50	-19.3%
CO-WORKER CONNECTIONS	11	$ 164,100.91	$ 186,936.00	-12.2%
CREDIT & COLLECTIONS	1	$ 123,760.00	$ 118,997.00	4.0%
CUSTOMER SERVICE	45	$ 105,735.38	$ 107,277.82	-1.4%
CYBER SECURITY	106	$ 146,640.53	$ 158,756.13	-7.6%
DATA SCIENCE	39	$ 140,300.21	$ 151,924.28	-7.7%
DATABASE ADMINISTRATION	3	$ 129,928.00	$ 144,563.00	-10.1%
DESIGN SERVICES	2	$ 121,120.00	$ 129,004.50	-6.1%
DIVERSITY EQUITY & INCLUSION	5	$ 147,140.40	$ 169,150.80	-13.0%
DOCUMENTATION & RECORD KEEPING	7	$ 96,379.43	$ 107,591.29	-10.4%
ELECTRICAL	193	$ 128,561.24	$ 138,157.00	-6.9%
EMPLOYEE RELATIONS	19	$ 148,949.79	$ 161,235.85	-7.6%
ENGINEERING & TECHNICAL LEADERSHIP	184	$ 172,388.10	$ 191,884.53	-10.2%
ENVIRONMENTAL & EMPLOYEE HEALTH & SAFETY	66	$ 136,270.45	$ 152,526.37	-10.7%
ETHICS & COMPLIANCE	39	$ 130,703.33	$ 131,632.17	-0.7%
EXPLORATION & PRODUCTION OPERATIONS	86	$ 149,687.63	$ 152,771.95	-2.0%
FACILITIES MANAGEMENT & PLANNING	8	$ 131,475.25	$ 129,797.63	1.3%
FINANCIAL CONTROL	14	$ 134,400.57	$ 131,591.07	2.1%
FINANCIAL FORECASTING	80	$ 141,381.45	$ 148,388.03	-4.7%
HR TECHNOLOGY	5	$ 125,850.80	$ 136,640.80	-7.9%
INDUSTRIAL	16	$ 132,366.50	$ 143,842.06	-8.0%
INFORMATION & TECHNOLOGY LEADERSHIP	55	$ 199,398.80	$ 234,061.38	-14.8%
INFORMATION & TECHNOLOGY MANAGEMENT	41	$ 141,234.54	$ 149,665.68	-5.6%
INTERNAL AUDIT	9	$ 159,098.22	$ 175,333.22	-9.3%
INVESTOR RELATIONS	3	$ 153,640.67	$ 173,258.00	-11.3%
LABOR RELATIONS	9	$ 120,248.89	$ 138,486.67	-13.2%
LABORATORY SERVICES	26	$ 120,528.23	$ 127,147.27	-5.2%
LEARNING & DEVELOPMENT	66	$ 113,480.15	$ 121,311.85	-6.5%
LEGAL PROFESSIONALS	27	$ 198,369.19	$ 258,204.52	-23.2%
MACHINE OPERATIONS	6	$ 152,793.67	$ 148,548.00	2.9%
MANUFACTURING PLANT MANAGEMENT	5	$ 186,602.40	$ 206,491.80	-9.6%
MARKETING GENERALISTS	37	$ 124,937.41	$ 129,342.35	-3.4%
MECHANICAL	102	$ 131,851.75	$ 137,826.43	-4.3%
ORGANIZATIONAL DEVELOPMENT	12	$ 128,621.67	$ 141,528.75	-9.1%
PAYROLL	4	$ 110,328.00	$ 107,880.00	2.3%
PHYSICAL SECURITY	8	$ 132,266.25	$ 170,793.13	-22.6%
POWER GEN TRANSMISSION & DISTRIBUTION	336	$ 131,753.57	$ 141,904.12	-7.2%
PROCUREMENT	43	$ 112,111.21	$ 124,892.57	-10.2%
PROGRAM MANAGEMENT	35	$ 142,727.03	$ 151,307.43	-5.7%
PROJECT & PROGRAM MANAGEMENT	73	$ 137,650.47	$ 148,489.43	-7.3%
PROPERTY MANAGEMENT	3	$ 100,378.67	$ 152,288.00	-34.1%
RATES & REGULATION	16	$ 158,125.63	$ 197,088.63	-19.8%
REAL ESTATE MANAGEMENT	28	$ 123,979.21	$ 148,719.96	-16.6%
REGULATORY AFFAIRS	6	$ 164,022.67	$ 186,753.00	-12.2%
RELATIONSHIP MANAGEMENT	34	$ 148,569.35	$ 163,834.44	-9.3%
REPAIR & MAINTENANCE TRADES	19	$ 153,092.63	$ 156,453.95	-2.1%
RISK MANAGEMENT	18	$ 146,786.56	$ 162,600.11	-9.7%
SALES & MARKETING	42	$ 159,145.86	$ 186,786.71	-14.8%
SOFTWARE DEVELOPMENT	11	$ 118,512.73	$ 136,234.00	-13.0%
SOFTWARE PRODUCT ENGINEERING	193	$ 135,603.16	$ 155,995.31	-13.1%
SUPPLY CHAIN PLANNING & OPERATIONS	42	$ 130,129.71	$ 126,351.28	3.0%
SYSTEMS ADMINISTRATION & REPORTING	3	$ 123,944.00	$ 124,644.33	-0.6%
SYSTEMS ARCHITECTURE	25	$ 156,723.52	$ 173,753.08	-9.8%
SYSTEMS OPS & PRODUCTION CONTROL	3	$ 141,192.00	$ 113,487.00	24.4%
TALENT ACQUISITION	10	$ 113,414.80	$ 112,665.00	0.7%
TAX	13	$ 151,511.85	$ 144,306.79	5.0%
TECHNICAL ANALYST	219	$ 114,366.74	$ 125,683.75	-9.0%
TECHNOLOGY SUPPORT	17	$ 112,753.88	$ 121,459.00	-7.2%
TELECOM & INTERNET	3	$ 112,594.67	$ 117,738.00	-4.4%
TREASURY	4	$ 146,669.00	$ 155,996.75	-6.0%
UTILITIES OPERATIONS	361	$ 142,282.30	$ 151,881.46	-6.3%
WAREHOUSING & DISTRIBUTION	18	$ 112,636.44	$ 114,691.79	-1.8%
WORKFORCE ANALYTICS	4	$ 130,609.00	$ 125,870.00	3.8%
Grand Total	**3597**			**-6.8%**

Non-Exempt:
2025 Market study

Job Family	# of Employees	Average Total Target Cash Actual	Average Market Total Cash 50th	Average Total Target Cash to Average Market Total
ACCOUNTING	8	$ 74,341.88	$ 82,274.75	-9.6%
ACCOUNTS PAYABLE & RECEIVABLE	71	$ 66,972.65	$ 60,662.70	10.4%
ADMINISTRATIVE SUPPORT	36	$ 66,545.22	$ 59,198.58	12.4%
ASSET PROCUREMENT	1	$ 62,572.00	$ 69,238.00	-9.6%
BUSINESS PROCESS & SERVICE QUALITY	15	$ 76,288.00	$ 71,302.20	7.0%
CREDIT & COLLECTIONS	5	$ 63,135.80	$ 67,448.20	-6.4%
CUSTOMER SERVICE	19	$ 64,069.68	$ 70,479.16	-9.1%
CYBER SECURITY	18	$ 61,535.78	$ 74,090.00	-16.9%
DESIGN SERVICES	1	$ 124,647.00	$ 104,158.00	19.7%
DOCUMENTATION & RECORD KEEPING	13	$ 68,860.69	$ 61,454.54	12.1%
EMPLOYEE RELATIONS	5	$ 70,960.00	$ 70,435.40	0.7%
ENGINEERING TECHNOLOGISTS & TECHNICIANS	261	$ 86,654.86	$ 92,651.15	-6.5%
ENVIRONMENTAL & EMPLOYEE HEALTH & SAFETY	4	$ 66,910.50	$ 55,223.00	21.2%
ETHICS & COMPLIANCE	30	$ 69,864.43	$ 72,603.93	-3.8%
FACILITIES MANAGEMENT & PLANNING	2	$ 53,715.00	$ 50,342.50	6.7%
HEAVY EQUIPMENT & CONSTRUCTION TRADES	5	$ 68,731.80	$ 62,588.60	9.8%
LABORATORY SERVICES	32	$ 79,653.53	$ 91,021.47	-12.5%
LEGAL PROFESSIONALS	4	$ 94,783.50	$ 106,576.50	-11.1%
MACHINE OPERATIONS	74	$ 79,723.54	$ 57,040.07	39.8%
PAYROLL	15	$ 64,882.40	$ 62,466.27	3.9%
POWER GEN TRANSMISSION & DISTRIBUTION	121	$ 75,686.77	$ 72,426.34	4.5%
PROCUREMENT	3	$ 64,173.33	$ 76,055.00	-15.6%
PROJECT & PROGRAM MANAGEMENT	150	$ 81,722.49	$ 67,799.73	20.5%
PROPERTY MANAGEMENT	6	$ 65,770.67	$ 70,974.33	-7.3%
REGULATORY AFFAIRS	17	$ 74,761.41	$ 78,485.82	-4.7%
REPAIR & MAINTENANCE TRADES	25	$ 87,631.64	$ 85,060.96	3.0%
UTILITIES OPERATIONS	33	$ 76,551.24	$ 70,975.09	7.9%
WAREHOUSING & DISTRIBUTION	5	$ 58,365.00	$ 59,227.40	-1.5%
Grand Total	**981**			**0.00%**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Annual Employee Incentive Compensation
($000)

Case No.: U-22070
Exhibit No.: A-72 (AMC-3)
Page: 1 of 2
Witness: AMConrad
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
1	**Officer Annual Incentive Compensation**	**$ 436**	**$ 515**
	Labor	436	515
	Material	-	-
	Contractor	-	-
	Non-Labor Overheads	-	-
	Non-Labor Other	-	-
2	**Non-Officer Annual Incentive Compensation**	**1,807**	**1,738**
	Labor	1,807	1,738
	Material	-	-
	Contractor	-	-
	Non-Labor Overheads	-	-
	Non-Labor Other	-	-
3	**Total Annual Employee Incentive Compensation**	**$ 2,243**	**$ 2,253**
	Labor	2,243	2,253
	Material	-	-
	Contractor	-	-
	Non-Labor Overheads	-	-
	Non-Labor Other	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Annual Employee Incentive Compensation
($000)

Case No.: U-22070
Exhibit No.: A-72 (AMC-3)
Page: 2 of 2
Witness: AMConrad
Date: June 2026

Line No.	(a) Description	(b) Actual 12 Mos Ending 12/31/2025	(c) Inflation Applied to Projected Test Year (b) * Compounded Inflation Rate	(d) Scope/ Cost Increases Net of Productivity Gains	(e) Projected O&M 12 Mos Ending 4/30/2028 (b) + (c) + (d)
1	Officer Annual Incentive Compensation	$ 436	$ 27	$ 52	$ 515
2	Non-Officer Annual Incentive Compensation	1,807	113	(182)	1,738
3	**Total Annual Employee Incentive Compensation**	**$ 2,243**	**$ 140**	**$ (130)**	**$ 2,253**

Notes

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	Executive	Position	Base Salary	Target Annual Incentive ($)	Target Annual Incentive (%)	Target Total Cash Compensation [1]	Total Long-Term Incentive	Target Total Direct Compensation [2]
Alliant Energy Corp	Lisa M. Barton	Pres. & CEO	$1,139,500	$1,424,375	125%	$2,563,875	$5,471,255	$8,035,130
Ameren Corporation	Martin J. Lyons Jr.	Chair, Pres. & CEO, Ameren	$1,325,000	$1,722,500	130%	$3,047,500	$8,205,550	$11,253,050
Atmos Energy Corporation	John K. Akers	Pres. & CEO	$1,165,000	$1,398,000	120%	$2,563,000	$5,179,057	$7,742,057
CenterPoint Energy, Inc.	Jason P. Wells	COB, Pres. & CEO	$1,250,000	$1,625,000	130%	$2,875,000	$7,625,023	$10,500,023
Consolidated Edison, Inc.	Timothy P. Cawley	Chair, Pres. & CEO of the Co. & CEO, Con Edison of NY	$1,450,000	$1,957,500	135%	$3,407,500	$9,773,900	$13,181,400
DTE Energy Company	Joi Harris	Pres. & CEO	$1,200,000	$1,500,000	125%	$2,700,000	$6,333,333	$9,033,333
Edison International	Pedro J. Pizarro	Pres. & CEO	$1,420,000	$1,917,000	135%	$3,337,000	$9,656,104	$12,993,104
Entergy Corporation	Andrew S. Marsh	Chair & CEO	$1,300,000	$1,755,000	135%	$3,055,000	$8,599,377	$11,654,377
Evergy, Inc.	David A. Campbell	Chair, Pres. & CEO	$1,125,000	$1,406,250	125%	$2,531,250	$7,004,447	$9,535,697
Eversource Energy	Joseph R. Nolan Jr.	Chair, Pres. & CEO	$1,442,000	$2,018,800	140%	$3,460,800	$9,020,890	$12,481,690
Hawaiian Electric Industries, Inc.	Scott W. H. Seu	President & CEO	$1,024,900	$1,229,880	120%	$2,254,780	$3,361,290	$5,616,070
NiSource Inc	Lloyd Yates	Pres. & CEO	$1,200,000	$1,560,000	130%	$2,760,000	$9,619,870	$12,379,870
OGE Energy Corp.	Sean Trauschke	COB, Pres. & CEO of the Company & of OG&E	$1,240,762	$1,488,914	120%	$2,729,676	$5,811,824	$8,541,500
Pinnacle West Capital Corporation	Theodore N. Geisler	COB, Pres. & CEO	$1,000,000	$1,200,000	120%	$2,200,000	$5,257,108	$7,457,108
PPL Corporation	Vincent Sorgi	Pres. & CEO	$1,238,060	$1,609,478	130%	$2,847,538	$7,865,249	$10,712,787
Public Service Enterprise Group Incorporated	Ralph A. LaRossa	COB, Pres. & CEO	$1,386,000	$1,871,100	135%	$3,257,100	$9,000,154	$12,257,254
Sempra Energy	Jeffrey W. Martin	Chair, CEO & Pres.	$1,700,000	$3,060,000	180%	$4,760,000	$14,453,933	$19,213,933
WEC Energy Group Inc	Scott J. Lauber	Pres. & CEO	$1,189,500	$1,724,775	145%	$2,914,275	$6,396,083	$9,310,358
Xcel Energy Inc.	Bob Frenzel	Chair, Pres. & CEO	$1,450,000	$2,102,500	145%	$3,552,500	$11,244,159	$14,796,659
n=19								
		Summary Statistics[3]						
		25th Percentile	$1,177,250	$1,456,645	125%	$2,631,938	$6,072,579	$8,787,417
		50th Percentile	$1,240,762	$1,625,000	130%	$2,875,000	$7,865,249	$10,712,787
		Average	$1,276,091	$1,714,267	133%	$2,990,358	$7,888,348	$10,878,705
		75th Percentile	$1,403,000	$1,894,050	135%	$3,297,050	$9,320,380	$12,430,780
CMS Energy Corporation	**Garrick J. Rochow**	**Pres. & CEO**	**$1,275,000**	**$1,593,750**	**125%**	**$2,868,750**	**$6,763,239**	**$9,631,989**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Second Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	Executive	Position	Base Salary	Target Annual Incentive ($)	Target Annual Incentive (%)	Target Total Cash Compensation [1]	Total Long-Term Incentive	Target Total Direct Compensation [2]
Alliant Energy Corp	Antonio Smyth	EVP of Power Generation & Gas Strategy	$635,000	$508,000	80%	$1,143,000	$2,999,569	$4,142,569
Ameren Corporation	Michael L. Moehn	Group Pres., Ameren Utilities, Ameren	$895,000	$805,500	90%	$1,700,500	$3,491,892	$5,192,392
Atmos Energy Corporation	Christopher T. Forsythe	SVP & CFO	$610,000	$488,000	80%	$1,098,000	$1,266,292	$2,364,292
CenterPoint Energy, Inc.	Christopher A. Foster	EVP & CFO	$760,000	$608,000	80%	$1,368,000	$2,204,004	$3,572,004
Consolidated Edison, Inc.	Matthew Ketschke	Pres., Con Edison of New York	$852,800	$682,240	80%	$1,535,040	$2,763,967	$4,299,007
DTE Energy Company	David Ruud	Vice Chair & CFO	$800,000	$800,000	100%	$1,600,000	$2,733,333	$4,333,333
Edison International	Maria Rigatti	EVP & CFO	$850,000	$756,500	89%	$1,606,500	$2,571,391	$4,177,891
Entergy Corporation	Kimberly A. Fontan	EVP & CFO	$748,625	$673,763	90%	$1,422,388	$1,908,215	$3,330,603
Evergy, Inc.	W. Bryan Buckler	EVP & CFO	$675,000	$540,000	80%	$1,215,000	$1,685,600	$2,900,600
Eversource Energy	John M. Moreira	EVP, CFO & Treasurer	$876,000	$700,800	80%	$1,576,800	$2,419,969	$3,996,769
Hawaiian Electric Industries, Inc.	Shelee M. T. Kimura	Hawaiian Electric President & CEO	$704,000	$563,200	80%	$1,267,200	$1,282,964	$2,550,164
NiSource Inc	Michael Luhrs	EVP, Technology, Customer & Chief Commercial Officer	$650,000	$487,500	75%	$1,137,500	$2,248,876	$3,386,376
OGE Energy Corp.	Charles B. Walworth	CFO of the Company & of OG&E	$560,019	$392,013	70%	$952,032	$983,640	$1,935,672
Pinnacle West Capital Corporation	Andrew D. Cooper	SVP & CFO	$680,000	$476,000	70%	$1,156,000	$1,787,327	$2,943,327
PPL Corporation	Joseph P. Bergstein Jr.	EVP & CFO	$725,708	$616,852	85%	$1,342,560	$1,997,817	$3,340,377
Public Service Enterprise Group Incorporated	Daniel J. Cregg	EVP & CFO	$854,000	$768,600	90%	$1,622,600	$2,500,112	$4,122,712
Sempra Energy	Justin C. Bird	EVP, CEO, Sempra Infrastructure	$940,000	$940,000	100%	$1,880,000	$2,614,233	$4,494,233
WEC Energy Group Inc	Xia Liu	EVP & CFO	$873,385	$742,377	85%	$1,615,762	$2,105,901	$3,721,663
Xcel Energy Inc.	Brian Van Abel	EVP & CFO	$840,000	$714,000	85%	$1,554,000	$2,402,219	$3,956,219
n=19								
		Summary Statistics[3]						
		25th Percentile	$677,500	$524,000	80%	$1,185,500	$1,847,771	$3,136,965
		50th Percentile	$760,000	$673,763	80%	$1,422,388	$2,248,876	$3,721,663
		Average	$764,712	$645,439	84%	$1,410,152	$2,208,806	$3,618,958
		75th Percentile	$853,400	$749,439	90%	$1,603,250	$2,592,812	$4,160,230
CMS Energy Corporation	**Rejji P. Hayes**	**EVP & CFO**	**$885,000**	**$708,000**	**80%**	**$1,593,000**	**$2,088,690**	**$3,681,690**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Third Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	Executive	Position	Base Salary	Target Annual Incentive ($)	Target Annual Incentive (%)	Target Total Cash Compensation [1]	Total Long-Term Incentive	Target Total Direct Compensation [2]
Alliant Energy Corp	Robert J. Durian	EVP & CFO	$700,000	$595,000	85%	$1,295,000	$1,680,516	$2,975,516
Ameren Corporation	Leonard P. Singh	EVP & CFO, Ameren	$650,000	$520,000	80%	$1,170,000	$1,730,861	$2,900,861
Atmos Energy Corporation	Jessica W. Bateman	SVP, GC & Corporate Secretary	$550,000	$385,000	70%	$935,000	$828,535	$1,763,535
CenterPoint Energy, Inc.	Monica Karuturi	EVP & GC	$750,000	$600,000	80%	$1,350,000	$2,024,977	$3,374,977
Consolidated Edison, Inc.	Kirkland Andrews	SVP & CFO of the Company & Con Edison of New York	$838,400	$670,720	80%	$1,509,120	$1,900,228	$3,409,348
DTE Energy Company	Trevor F. Lauer	Vice Chair & Group Pres.	$696,077	$561,600	81%	$1,257,677	$1,665,899	$2,923,576
Edison International	Steven D. Powell	Pres. & CEO, SCE	$850,000	$756,500	89%	$1,606,500	$2,571,391	$4,177,891
Entergy Corporation	Marcus V. Brown	Former EVP & GC & Executive Legal Advisor to the CEO	$819,465	$655,572	80%	$1,475,037	$1,647,871	$3,122,908
Evergy, Inc.	Charles A. Caisley	EVP, Utility Operations & Chief Customer Officer	$585,000	$409,500	70%	$994,500	$1,882,926	$2,877,426
Eversource Energy	Paul W. Chodak III	EVP & COO	$876,000	$700,800	80%	$1,576,800	$2,191,672	$3,768,472
Hawaiian Electric Industries, Inc.	Scott T. DeGhetto	EVP & CFO	$800,000	$1,200,000	150%	$2,000,000	$450,000	$2,450,000
NiSource Inc	Shawn Anderson	EVP & CFO	$675,000	$506,250	75%	$1,181,250	$1,818,069	$2,999,319
OGE Energy Corp.	William H. Sultemeier	GC, Corporate Secretary & Chief Compliance Officer	$532,917	$373,042	70%	$905,959	$873,673	$1,779,632
Pinnacle West Capital Corporation	Jacob Tetlow	EVP & COO of APS	$700,000	$525,000	75%	$1,225,000	$1,673,955	$2,898,955
PPL Corporation	Wendy E. Stark	EVP - Utilities & CLO	$663,400	$563,890	85%	$1,227,290	$1,545,413	$2,772,703
Public Service Enterprise Group Incorporated	Kim C. Hanemann	Pres. & COO, PSE&G	$802,100	$681,785	85%	$1,483,885	$2,000,089	$3,483,974
Sempra Energy	Karen L. Sedgwick	EVP & CFO	$700,000	$630,000	90%	$1,330,000	$2,651,070	$3,981,070
WEC Energy Group Inc	Michael W. Hooper	EVP, COO & Pres. Subsidiary	$713,000	$606,050	85%	$1,319,050	$1,279,860	$2,598,910
Xcel Energy Inc.	Amanda Rome	EVP, Group Pres., Utilities & Chief Customer Officer	$775,000	$658,750	85%	$1,433,750	$1,942,199	$3,375,949
n=19								
		Summary Statistics [3]						
		25th Percentile	$669,200	$522,500	78%	$1,203,125	$1,596,642	$2,825,065
		50th Percentile	$700,000	$600,000	80%	$1,319,050	$1,730,861	$2,975,516
		Average	$719,808	$610,498	84%	$1,330,306	$1,703,116	$3,033,422
		75th Percentile	$801,050	$664,735	85%	$1,479,461	$1,971,144	$3,392,649
CMS Energy Corporation	**Shaun M. Johnson**	**EVP, Business Transformation, Chief Legal & Administrative Officer**	**$700,000**	**$560,000**	**80%**	**$1,260,000**	**$1,223,401**	**$2,483,401**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Fourth Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	Executive	Position	Base Salary	Target Annual Incentive ($)	Target Annual Incentive (%)	Target Total Cash Compensation [1]	Total Long-Term Incentive	Target Total Direct Compensation [2]
Alliant Energy Corp	Raja Sundararajan	EVP – Strategy & Customer Solutions	$650,000	$520,000	80%	$1,170,000	$1,492,574	$2,662,574
Ameren Corporation	Shawn E. Schukar	Chair & Pres., Ameren Transmission Company of Illinois	$545,000	$408,750	75%	$953,750	$1,046,265	$2,000,015
Atmos Energy Corporation	John S. McDill	SVP, Utility Operations	$550,000	$385,000	70%	$935,000	$828,535	$1,763,535
CenterPoint Energy, Inc.	Jesus Soto Jr.	EVP & COO	$725,000	$580,000	80%	$1,305,000	$1,884,993	$3,189,993
Consolidated Edison, Inc.	Deneen L. Donnley	SVP & GC of the Company & Con Edison of New York	$720,000	$576,000	80%	$1,296,000	$1,554,732	$2,850,732
DTE Energy Company	Mark W. Stiers	Pres. & COO - DTE Vantage & Energy	$649,615	$491,250	76%	$1,140,865	$1,537,416	$2,678,281
Edison International	Chonda J. Nwamu	Executive Vie Pres. & GC	$745,000	$633,250	85%	$1,378,250	$2,464,060	$3,842,310
Entergy Corporation	Kimberly Cook Nelson	EVP & COO	$745,000	$596,000	80%	$1,341,000	$1,373,974	$2,714,974
Evergy, Inc.	Cleveland O. Reasoner III	SVP & Chief Nuclear Officer	$625,000	$375,000	60%	$1,000,000	$1,804,492	$2,804,492
Eversource Energy	Gregory B. Butler	EVP & GC	$754,000	$527,800	70%	$1,281,800	$1,414,850	$2,696,650
Hawaiian Electric Industries, Inc.	Kurt K. Murao	EVP, GC, Chief Admin. Officer & Corp. Secretary	$528,167	$396,125	75%	$924,292	$866,095	$1,790,387
NiSource Inc	Melody Birmingham	EVP & Group Pres., Utilities	$690,000	$517,500	75%	$1,207,500	$1,672,630	$2,880,130
OGE Energy Corp.	D.O. Jones	SVP, Utility Operations of OG&E	$468,187	$327,731	70%	$795,918	$822,359	$1,618,277
Pinnacle West Capital Corporation	Adam C. Heflin	EVP & Chief Nuclear Officer of PVGS, APS	$760,000	$570,000	75%	$1,330,000	$1,465,175	$2,795,175
PPL Corporation	Dean A. Del Vecchio	EVP & Chief Technology & Innovation Officer	$669,500	$569,075	85%	$1,238,575	$1,488,712	$2,727,287
Public Service Enterprise Group Incorporated	Grace H. Park	EVP & GC	$700,000	$560,000	80%	$1,260,000	$1,400,046	$2,660,046
Sempra Energy	Caroline A. Winn	EVP, CEO, SDG&E	$875,000	$875,000	100%	$1,750,000	$1,732,127	$3,482,127
WEC Energy Group Inc	Margaret C. Kelsey	EVP, GC & Corporate Secretary	$664,661	$498,496	75%	$1,163,157	$1,121,800	$2,284,957
Xcel Energy Inc.	Ryan Long	EVP, Chief Legal & Compliance Officer	$600,000	$450,000	75%	$1,050,000	$1,332,556	$2,382,556
n=19								
		Summary Statistics[3]						
		25th Percentile	$612,500	$429,375	75%	$1,025,000	$1,227,178	$2,333,756
		50th Percentile	$669,500	$520,000	75%	$1,207,500	$1,465,175	$2,696,650
		Average	$666,533	$518,788	77%	$1,185,321	$1,437,021	$2,622,342
		75th Percentile	$735,000	$573,000	80%	$1,300,500	$1,613,681	$2,827,612
CMS Energy Corporation	**LeeRoy Wells Jr.**	**SVP, Pres. - Gas Delivery**	**$585,000**	**$438,750**	**75%**	**$1,023,750**	**$1,084,014**	**$2,107,764**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Fifth Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company[1]	Executive	Position	Base Salary	Target Annual Incentive ($)	Target Annual Incentive (%)	Target Total Cash Compensation [2]	Total Long-Term Incentive	Target Total Direct Compensation [3]
Alliant Energy Corp	David A. de Leon	SVP, Operations	$480,000	$360,000	75%	$840,000	$651,289	$1,491,289
Ameren Corporation	Mark C. Lindgren	EVP, Communications & Chief Human Resources Officer, Ameren Service s	$482,500	$313,625	65%	$796,125	$776,898	$1,573,023
Atmos Energy Corporation	Karen E. Hartsfield	Senior Advisor	$550,000	$385,000	70%	$935,000	$828,535	$1,763,535
CenterPoint Energy, Inc.	Jason M. Ryan	EVP, Regulatory Services & Government Affairs	$535,000	$428,000	80%	$963,000	$1,070,025	$2,033,025
Consolidated Edison, Inc.	Kamran Ziaee	SVP & Chief Information Officer, Con Edison of New York	$535,500	$401,625	75%	$937,125	$1,172,868	$2,109,993
DTE Energy Company	Matthew Paul	Pres. & COO, DTE Electric Company	$616,538	$472,500	77%	$1,089,038	$1,271,051	$2,360,089
Edison International	Jill C. Anderson	EVP & COO, SCE	$560,000	$364,000	65%	$924,000	$1,078,135	$2,002,135
Entergy Corporation	John C. Dinelli	EVP & Chief Nuclear Officer	$625,000	$406,250	65%	$1,031,250	$960,609	$1,991,859
Evergy, Inc.	Heather A. Humphrey	SVP, GC & Corporate Secretary	$562,500	$365,625	65%	$928,125	$998,922	$1,927,047
Eversource Energy	James W. Hunt III	EVP, Corporate Relations & Sustainability & Secretary	$568,000	$397,600	70%	$965,600	$1,065,557	$2,031,157
NiSource Inc	William Jefferson	EVP, Chief Operating & Safety Officer	$650,000	$487,500	75%	$1,137,500	$1,575,681	$2,713,181
OGE Energy Corp.	David A. Parker	Chief Information Officer of OG&E	$378,602	$227,161	60%	$605,763	$443,353	$1,049,116
Pinnacle West Capital Corporation	Shirley A. Baum	SVP & GC, PNW & APS	$500,000	$300,000	60%	$800,000	$788,780	$1,588,780
PPL Corporation	David J. Bonenberger	EVP & COO - Utilities	$560,000	$476,000	85%	$1,036,000	$1,436,084	$2,472,084
Public Service Enterprise Group Incorporated	Charles V. McFeaters	Pres. & Chief Nuclear Officer	$700,000	$525,000	75%	$1,225,000	$1,300,106	$2,525,106
Sempra Energy	Diana L. Day	Chief Legal Counsel & Corporate Secretary	$600,000	$450,000	75%	$1,050,000	$1,315,176	$2,365,176
WEC Energy Group Inc	Robert M. Garvin	EVP, External Affairs	$612,789	$459,592	75%	$1,072,381	$1,027,494	$2,099,875
Xcel Energy Inc.	Michael Lamb	EVP & Chief Delivery Officer	$585,000	$380,250	65%	$965,250	$1,154,347	$2,119,597
n=18								
		Summary Statistics[4]						
		25th Percentile	$535,125	$364,406	65%	$925,031	$861,554	$1,804,413
		50th Percentile	$561,250	$399,613	73%	$964,125	$1,067,791	$2,032,091
		Average	$561,191	$399,985	71%	$961,175	$1,050,828	$2,012,004
		75th Percentile	$609,592	$457,194	75%	$1,046,500	$1,246,505	$2,299,966
CMS Energy Corporation	**Tonya L. Berry**	**EVP & COO**	**$635,000**	**$476,250**	**75%**	**$1,111,250**	**$795,694**	**$1,906,944**

Notes:

1. Hawaiian Electric only disclosed 4 NEOs in their 2026 proxy and do not have a 5th highest-paid officer.
2. Target TCC (total cash compensation) includes base salary and target annual incentive.
3. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
4. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Proxy Statement Summary Compensation Table

Case No.: U-22070
Exhibit No.: A-74 (AMC-5)
Page: 1 of 1
Witness: AMConrad
Date: June 2026

Below is the actual compensation of the named executive officers from the most recent Securities and Exchange Commission executive compensation public disclosure requirement under Regulation 14A (referred to as the proxy statement).

2025 SUMMARY COMPENSATION TABLE

Name and Principal Position (a)	Year (b)	Salary (1) ($) (c)	Stock Awards (2) ($) (e)	Non-Equity Incentive Plan Compensation (3) ($) (f)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (4) ($) (g)	All Other Compensation (5) ($) (h)	Total ($) (i)
Garrick J. Rochow	2025	1,275,000	6,763,239	2,055,938	251	439,611	10,534,039
President and CEO,	2024	1,250,000	6,651,245	2,078,125	261	421,778	10,401,409
CMS and Consumers	2023	1,235,000	6,033,036	1,945,125	198	423,851	9,637,210
Rejji P. Hayes	2025	860,123	2,088,690	887,647	—	250,427	4,086,887
Executive Vice President and CFO,	2024	810,000	2,082,626	861,840	—	256,918	4,011,384
CMS and Consumers	2023	790,000	1,936,135	796,320	—	233,154	3,755,609
Tonya L. Berry (6)	2025	585,411	795,694	532,161	—	118,647	2,031,913
Executive Vice President and COO,	2024	—	—	—	—	—	—
CMS and Consumers	2023	—	—	—	—	—	—
Shaun M. Johnson	2025	682,644	1,223,401	704,488	—	180,416	2,790,949
Executive Vice President, Business Transformation, Chief Legal & Administrative Officer	2024	620,000	1,249,550	618,450	—	160,576	2,648,576
CMS and Consumers	2023	565,000	1,006,849	533,925	—	157,421	2,263,195
Brandon J. Hofmeister	2025	600,000	914,933	503,100	—	151,763	2,169,796
Senior Vice President, Strategy, Sustainability and External Affairs,	2024	545,000	905,858	471,152	—	139,267	2,061,277
CMS and Consumers	2023	535,000	877,706	438,165	—	143,337	1,994,208
LeeRoy Wells Jr.	2025	585,000	1,084,014	565,988	—	160,605	2,395,607
Senior Vice President, President - Gas Delivery,	2024	575,000	1,067,357	573,562	—	135,586	2,351,505
Consumers	2023	545,000	955,139	480,690	—	132,003	2,112,832

(1) The amounts reported in this column include amounts deferred by the NEOs.

(2) The amounts represent the aggregate grant date fair value of the awards, which, with respect to those awards with a performance component, is based upon the probable outcome of the performance conditions, determined pursuant to ASC 718 and take into account the expected CMS common stock dividend yield associated with the 2023, 2024 and 2025 awards. See Note 12, Stock-based Compensation, to the Consolidated Financial Statements included in CMS' and Consumers' Annual Report on Form 10-K for the year ended December 31, 2025, for a discussion of the relevant assumptions used in calculating the aggregate grant date fair value pursuant to ASC 718. The TSR vesting condition related to the performance-based restricted stock awards is considered a market condition and not a performance condition under ASC 718. Accordingly, there is no grant date fair value below or in excess of the amounts reflected in the table above that could be calculated and disclosed based on achievement of market conditions. The EPS growth vesting condition is a performance condition under ASC 718.

The 2025 grant date fair value for the EPS growth performance-based restricted stock, based on the probable achievement of the performance goals at the time of grant, was $2,550,024 for Rochow; $787,515 for Hayes; $300,018 for Berry; $461,282 for Johnson; $344,968 for Hofmeister and $408,719 for Wells Jr.

The grant date fair value for the EPS growth performance-based restricted stock, assuming the maximum achievement of the performance goals, would have been $5,100,048 for Rochow; $1,575,030 for Hayes; $600,037 for Berry; $922,563 for Johnson; $689,936 for Hofmeister and $817,438 for Wells Jr.

(3) The amounts reported in this column for 2025 consist of cash incentive awards earned in 2025 under our Annual Incentive Plan.

(4) This column does not reflect compensation paid to the NEO but instead represents the aggregate annual increase, as of December 31, 2023, December 31, 2024 and December 31, 2025, in actuarial values of each of the participating NEO's benefits under the Cash Balance Plan. The actuarial values are calculated pursuant to Financial Accounting Standards Board Accounting Codification Topic 715, Compensation — Retirement Benefits (ASC 715), and take into account discount rates and implementation of the current 2021 mortality table. See Note 11, Retirement Benefits, to the Consolidated Financial Statements included in CMS' and Consumers' Annual Report on

Form 10-K for the year ended December 31, 2025, for a discussion of the relevant assumptions used in determining these amounts. Rochow is the only NEO covered by the Cash Balance Plan.

(5) Detail supporting all other compensation for 2025 is reflected in the *2025 All Other Compensation Table*, below.

(6) Berry was not a NEO prior to 2025.

Consumers Energy Company
Allocation of Base Salary and Incentive Expense for the 2025 Historical Period

1. *Base Salary and Short-Incentive Company Allocation*

Base salaries and short-term incentive of the officers are allocated to CMS Energy, Consumers and NorthStar. The following officers have a portion of base salary allocated to other companies outside of Consumers Energy based on an estimated percentage of time spent.

- President & Chief Executive Officer
- Exec VP & Chief Financial Officer
- Executive VP Business Transformation & Chief Legal & Admin. Officer
- SVP People
- SVP Strategy Sustainability & External Affairs
- VP Corporate Secretary & Chief Compliance Officer
- VP Regulator & Legal Affairs & Deputy General Counsel
- VP Applications & Analytics
- VP IT & Security and Chief Info Officer

No officers have a portion of base salary and short-term incentive allocated to other companies outside of Consumers Energy based on customer count.

The following officers have a portion of base salary and short-term incentive allocated to other companies outside of Consumers Energy based on Massachusetts formula allocation.

- VP Controller & Chief Accounting Officer
- VP of Investor Relations and Treasury

The remaining officer roles have 100% of their base salary and short-term incentive allocated to Consumers Energy based on the fact that 100% of their time is spent on Consumers Energy.

2. *Base Salary Business Allocation (ie Electric and Gas Split)*

Operating and maintenance allocation of base salaries for the following officers were based on the three factors: (1) Net Plant, Investments, Inventory and Goodwill (2) the 12-month ended operating revenue (3) and 12 months ended payroll.

- President and Chief Executive Officer
- VP Controller & Chief Accounting Officer
- SVP Strategy Sustainability & External Affairs
- VP Corporate Secretary & Chief Compliance Officer
- Executive VP Business Transformation & Chief Legal & Admin. Officer
- VP Regulator & Legal Affairs & Deputy General Counsel

Operating and maintenance allocation of base salary for, SVP & Chief Customer Officer; VP Supply Chain and SVP Chief Customer & Growth Officer is based on customer count.

Operating and maintenance allocation of base salaries and short-term incentive for the following officers were based on bank balances ratio. Bank balances ratio is calculated as average electric and gas percentages of total construction expenditures and total operating and maintenance expense.

- Executive VP and Chief Financial Officer
- VP of Investor Relations and Treasury

Operating and maintenance allocation of base salaries for the EVP & Chief Operating Officer is based on their time spent on electric versus gas work and customer count.

Operating and maintenance allocation of base salaries for the, VP Community & Media Relations & Chief Diversity Officer; VP Applications & Analytics; and VP IT & Security and Chief Info Officer; is allocated between electric and gas based on a corporate headcount.

Operating and maintenance allocation of base salaries for the VP of Grid Ops Restoration & Work Management, SVP & President Electric Distribution and SVP & President Electric Supply and are allocated 100% to electric.

Operating and maintenance allocation of base salaries for the SVP and VPs responsible for Transformation, Engineering & Operation Support, are allocated to electric and gas based on the weighted average of operating and maintenance and construction dollars expended in the various functions (Engineering, Operations Support, and VP Renewables Development & Enterprise Prj. Mgmt.).

3. *Incentive Business Allocation (ie Electric and Gas Split)*

Electric and gas allocation of annual incentive for all officers is based on total Consumers' labor allocation within historical 12 months period.

4. *Base Salary and Incentive Cost Allocation (ie O&M and Capital)*

Annual incentive expense has always been considered a labor cost; however it was not categorized as one in the MPSC chart of accounts. Prior to Case No. U-17735 it was a "disallowed" labor cost. In Case No. U-16191, the Commission staff requested that payments in excess of rate recoverable charges (for example: incentive compensation plan, supplemental executive retirement plan, etc.) be recorded to account 426.5 "Other Deductions". The Company followed this order and charged incentive expense to account 426.5. In Case No. U-17735, the Commission approved the recovery of the short-term EICP program, which then allowed the Company to charge the approved short-term incentive costs to operating and maintenance expense and capital as a component of labor for the Company. The Company is currently splitting the cost of short-term incentive associated with operating goals at threshold level (50% of non-officer labor costs and 30% of officers) between operating and maintenance and capital based on time spent. Based on Case No. U-17990 only approving the recovery of the short-term incentive cost associated with operating goals, However, 100% of the top 5 officer annual incentive labor costs is allocated to account 426.5 "Other Deductions".

5. Base Salary and Incentive Cost Allocation %

HISTORICAL YEAR 2025

	Percentage Split		Percentage Split		Electric		Gas	
Officer TITLE	**Incentive Charged to Consumers**	**Other**	**Electric**	**Gas**	**% to O&M**	**% to Capital**	**% to O&M**	**% to Capital**
President & Chief Executive Officer CMS	90.00%	10.00%	62%	38%	48%	52%	36%	64%
EVP & Chief Financial Officer	85.00%	15.00%	62%	38%	48%	52%	36%	64%
EVP Bus Trans & Chief Lgl & Admin Off	80.00%	20.00%	62%	38%	48%	52%	36%	64%
EVP & Chief Operating Officer	100.00%	0.00%	62%	38%	48%	52%	36%	64%
SVP Strategy Sustainability & External Aff	80.00%	20.00%	62%	38%	48%	52%	36%	64%
VP Applications & Analytics	99.00%	1.00%	62%	38%	48%	52%	36%	64%
VP Lean	100.00%	0.00%	62%	38%	48%	52%	36%	64%
VP Community & Media Rel & Chief Div Off	100.00%	0.00%	62%	38%	48%	52%	36%	64%
VP Commercial Operations & Planning	100.00%	0.00%	62%	38%	48%	52%	36%	64%
VP Low Voltage Distribution	100.00%	0.00%	62%	38%	48%	52%	36%	64%
VP Elec Supply Dev & Origination	100.00%	0.00%	62%	38%	48%	52%	36%	64%
SVP & President Electric Distribution	100.00%	0.00%	62%	38%	48%	52%	36%	64%
VP Grid Ops Restoration & Work Mgmt	100.00%	0.00%	62%	38%	48%	52%	36%	64%
VP Investor Relations & Treasurer	95.80%	4.20%	62%	38%	48%	52%	36%	64%
VP Generation Operations	100.00%	0.00%	62%	38%	48%	52%	36%	64%
VP IT & Security and Chief Info Officer	99.00%	1.00%	62%	38%	48%	52%	36%	64%
SVP Reg & Lgl Aff & Dep General Counsel	80.00%	20.00%	62%	38%	48%	52%	36%	64%
SVP & Chief Customer & Growth Officer	100.00%	0.00%	62%	38%	48%	52%	36%	64%
SVP & President Gas Delivery	100.00%	0.00%	62%	38%	48%	52%	36%	64%

	Percentage Split		Percentage Split		Electric		Gas	
Officer TITLE	Incentive Charged to Consumers	Other	Electric	Gas	% to O&M	% to Capital	% to O&M	% to Capital
VP Corp Secretary & Chief Compliance Ofr	50.00%	50.00%	62%	38%	48%	52%	36%	64%
VP Grid Ops Restoration & Work Mgmt	100.00%	0.00%	62%	38%	48%	52%	36%	64%
VP Controller & Chief Accounting Officer	95.80%	4.20%	62%	38%	48%	52%	36%	64%
VP Supply Chain	100.00%	0.00%	62%	38%	48%	52%	36%	64%
SVP & President Electric Supply	100.00%	0.00%	62%	38%	48%	52%	36%	64%
SVP People	98.61%	1.39%	62%	38%	48%	52%	36%	64%

EVP= Executive Vice President; SVP= Senior President; VP= Vice President

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-22070

EXHIBITS

OF

EMILY A. DAVIS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost of Service Study

Schedule F-1

Case No.: U-22070
Exhibit No.:A-16 (EAD-1)
Schedule F-1
Page: 1 of 28
Witness: EADavis
Date: June 2026

Projected 12-Month Period Ending April 30, 2028
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Rate Base**	17,022,569	10,060,269	4,330,250	241,151	2,358,073	32,825
2	**Revenue**						
3	Total Rate Revenue	4,649,142	2,504,280	1,163,783	44,245	934,894	1,939
4	Total Revenue Credits	1,042,314	475,365	243,221	4,746	303,650	15,331
5	Total Revenue	5,691,456	2,979,645	1,407,005	48,992	1,238,545	17,270
6	**Expenses:**						
7	Fuel and P&I Expense	2,062,434	905,432	495,064	9,899	642,663	9,377
8	Transmission Expense	703,549	335,866	167,595	2,235	195,494	2,359
9	Other O & M Expense	796,074	506,554	194,179	7,194	87,175	972
10	Depreciation & Amortization Expense	854,516	492,151	210,641	14,065	135,851	1,807
11	Other Taxes	379,764	218,567	99,943	2,129	58,287	838
12	Federal Income Taxes	77,450	45,086	20,730	1,166	10,303	166
13	Total Expenses	4,873,787	2,503,656	1,188,152	36,687	1,129,773	15,519
14	Net Operating Income	817,669	475,989	218,853	12,305	108,771	1,751
15	Other Income Adjustments	17,040	9,930	4,395	86	2,595	35
16	Adjusted Net Operating Income	834,709	485,919	223,247	12,390	111,366	1,786
17	Return on Rate Base @ 6.59%	1,122,345	663,301	285,505	15,900	155,474	2,164
18	Income Deficiency (Sufficiency)	287,636	177,382	62,258	3,509	44,108	379
19	Revenue Deficiency (Sufficiency)	384,880	237,351	83,306	4,696	59,020	507
20	Additional Rev Requirement	70,954	35,538	16,775	205	18,191	245
21	Total Revenue Deficiency (Sufficiency)	455,834	272,889	100,082	4,901	77,211	751
22	Revenue Requirement/Total Cost of Service	6,147,290	3,252,534	1,507,086	53,892	1,315,756	18,021
23	Less: Revenue Credits	1,042,314	475,365	243,221	4,746	303,650	15,331
24	**Proposed Rate Design Revenue**	**5,104,976**	**2,777,169**	**1,263,865**	**49,146**	**1,012,106**	**2,690**
	Increase over Present Revenue	**455,834**	**272,889**	**100,082**	**4,901**	**77,211**	**751**
		9.8%	**10.9%**	**8.6%**	**11.1%**	**8.3%**	**38.7%**
25	Production: Net Capacity Cost	677,033	355,401	158,972	1,383	159,276	2,001
26	Production: Capacity Related Cost Offset	588,511	274,643	138,466	2,420	170,716	2,265
27	Production: Non-Capacity Related Cost	1,397,291	604,552	342,977	6,784	447,727	(4,749)
28	Distribution: Demand Related Cost	2,172,171	1,341,987	573,146	36,915	217,070	3,054
29	Distribution: Customer Related Cost	269,970	200,586	50,304	1,644	17,317	119
30	Full Service MWH Sales	29,964,807	12,513,512	7,044,071	158,121	10,095,910	153,194
31	ROA MWH Sales	3,588,440	-	185,056	-	3,403,384	-
32	MWH Sales	33,553,247	12,513,512	7,229,126	158,121	13,499,294	153,194
33	Customers	1,918,306	1,678,227	230,395	5,547	4,122	14

Projected 12-Month Period Ending April 30, 2028
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Rate Base**	10,060,269	10,060,269	2,756,211	1,574,039	4,330,250	8,686	203,322	29,144	241,151
2	**Revenue**									
3	Total Rate Revenue	2,504,280	2,504,280	727,657	436,126	1,163,783	1,744	32,815	9,687	44,245
4	Total Revenue Credits	475,365	475,365	146,757	96,464	243,221	282	1,692	2,773	4,746
5	Total Revenue	2,979,645	2,979,645	874,415	532,590	1,407,005	2,025	34,506	12,460	48,992
6	**Expenses:**									
7	Fuel and P&I Expense	905,432	905,432	296,771	198,293	495,064	602	3,233	6,064	9,899
8	Transmission Expense	335,866	335,866	102,853	64,742	167,595	122	528	1,584	2,235
9	Other O & M Expense	506,554	506,554	125,644	68,535	194,179	346	5,524	1,323	7,194
10	Depreciation & Amortization Expense	492,151	492,151	134,527	76,114	210,641	401	12,182	1,483	14,065
11	Other Taxes	218,567	218,567	62,581	37,362	99,943	151	1,270	708	2,129
12	Federal Income Taxes	45,086	45,086	13,155	7,575	20,730	35	1,018	112	1,166
13	Total Expenses	2,503,656	2,503,656	735,531	452,621	1,188,152	1,656	23,756	11,275	36,687
14	Net Operating Income	475,989	475,989	138,884	79,969	218,853	370	10,750	1,185	12,305
15	Other Income Adjustments	9,930	9,930	2,759	1,636	4,395	6	47	32	86
16	Adjusted Net Operating Income	485,919	485,919	141,642	81,605	223,247	376	10,798	1,217	12,390
17	Return on Rate Base @ 6.59%	663,301	663,301	181,725	103,781	285,505	573	13,406	1,922	15,900
18	Income Deficiency (Sufficiency)	177,382	177,382	40,082	22,176	62,258	197	2,608	704	3,509
19	Revenue Deficiency (Sufficiency)	237,351	237,351	53,633	29,673	83,306	264	3,490	943	4,696
20	Additional Rev Requirement	35,538	35,538	10,309	6,466	16,775	7	44	154	205
21	Total Revenue Deficiency (Sufficiency)	272,889	272,889	63,943	36,139	100,082	271	3,533	1,097	4,901
22	Revenue Requirement/Total Cost of Service	3,252,534	3,252,534	938,358	568,729	1,507,086	2,296	38,040	13,557	53,892
23	Less: Revenue Credits	475,365	475,365	146,757	96,464	243,221	282	1,692	2,773	4,746
24	**Proposed Rate Design Revenue**	**2,777,169**	**2,777,169**	**791,600**	**472,265**	**1,263,865**	**2,014**	**36,348**	**10,784**	**49,146**
	Increase over Present Revenue	272,889	272,889	63,943	36,139	100,082	271	3,533	1,097	4,901
		10.9%	10.9%	8.8%	8.3%	8.6%	15.5%	10.8%	11.3%	11.1%
25	Production: Net Capacity Cost	355,401	355,401	98,772	60,200	158,972	6	134	1,243	1,383
26	Production: Capacity Related Cost Offset	274,643	274,643	83,542	54,925	138,466	128	721	1,571	2,420
27	Production: Non-Capacity Related Cost	604,552	604,552	205,941	137,035	342,977	433	2,178	4,172	6,784
28	Distribution: Demand Related Cost	1,341,987	1,341,987	363,344	209,802	573,146	1,364	31,851	3,701	36,915
29	Distribution: Customer Related Cost	200,586	200,586	40,001	10,303	50,304	84	1,463	97	1,644
30	Full Service MWH Sales	12,513,512	12,513,512	4,189,989	2,854,081	7,044,071	10,465	54,935	92,721	158,121
31	ROA MWH Sales	-	-	17,123	167,933	185,056	-	-	-	-
32	MWH Sales	12,513,512	12,513,512	4,207,112	3,022,014	7,229,126	10,465	54,935	92,721	158,121
33	Customers	1,678,227	1,678,227	210,102	20,293	230,395	386	4,700	460	5,547

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Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Rate Base**	202,338	41,810	68,817	910,108	183,005	299,215	603,248	39,678	8,186	1,667	2,358,073
2	**Revenue**											
3	Total Rate Revenue	72,633	25,842	34,541	359,550	88,939	122,832	203,719	21,881	4,193	764	934,894
4	Total Revenue Credits	20,086	9,075	11,777	111,738	33,082	43,830	63,019	9,372	1,483	188	303,650
5	Total Revenue	92,719	34,917	46,318	471,289	122,021	166,662	266,738	31,253	5,676	952	1,238,545
6	**Expenses:**											
7	Fuel and P&I Expense	42,227	19,528	25,251	236,526	70,737	93,354	131,131	20,261	3,199	449	642,663
8	Transmission Expense	14,042	5,610	7,698	75,889	19,631	26,983	38,739	5,876	888	139	195,494
9	Other O & M Expense	7,418	1,649	2,384	35,251	6,461	9,307	22,727	1,633	283	64	87,175
10	Depreciation & Amortization Expense	11,402	2,997	4,449	53,055	11,463	16,723	32,227	2,946	506	84	135,851
11	Other Taxes	4,658	1,215	1,745	21,792	5,440	7,696	14,479	1,007	212	42	58,287
12	Federal Income Taxes	1,122	339	415	4,220	717	1,090	2,374	(41)	51	15	10,303
13	Total Expenses	80,870	31,338	41,941	426,732	114,450	155,152	241,676	31,682	5,139	793	1,129,773
14	Net Operating Income	11,850	3,579	4,377	44,557	7,571	11,510	25,062	(430)	537	159	108,771
15	Other Income Adjustments	209	51	82	1,035	188	323	645	51	10	2	2,595
16	Adjusted Net Operating Income	12,059	3,630	4,458	45,591	7,759	11,833	25,707	(379)	547	161	111,366
17	Return on Rate Base @ 6.59%	13,341	2,757	4,537	60,006	12,066	19,728	39,774	2,616	540	110	155,474
18	Income Deficiency (Sufficiency)	1,282	(873)	79	14,415	4,307	7,895	14,066	2,995	(7)	(51)	44,108
19	Revenue Deficiency (Sufficiency)	1,716	(1,168)	106	19,288	5,763	10,565	18,822	4,007	(10)	(68)	59,020
20	Additional Rev Requirement	1,306	505	705	7,119	1,684	2,419	3,850	515	80	9	18,191
21	Total Revenue Deficiency (Sufficiency)	3,022	(664)	810	26,407	7,447	12,984	22,672	4,522	70	(59)	77,211
22	Revenue Requirement/Total Cost of Service	95,741	34,253	47,128	497,696	129,467	179,647	289,410	35,775	5,746	892	1,315,756
23	Less: Revenue Credits	20,086	9,075	11,777	111,738	33,082	43,830	63,019	9,372	1,483	188	303,650
24	**Proposed Rate Design Revenue**	**75,655**	**25,178**	**35,351**	**385,957**	**96,386**	**135,816**	**226,391**	**26,403**	**4,263**	**705**	**1,012,106**
	Increase over Present Revenue	**3,022**	**(664)**	**810**	**26,407**	**7,447**	**12,984**	**22,672**	**4,522**	**70**	**(59)**	**77,211**
		4.2%	**-2.6%**	**2.3%**	**7.3%**	**8.4%**	**10.6%**	**11.1%**	**20.7%**	**1.7%**	**-7.8%**	**8.3%**
25	Production: Net Capacity Cost	11,902	4,213	6,062	63,899	13,850	20,445	34,042	4,172	633	58	159,276
26	Production: Capacity Related Cost Offset	11,224	4,657	6,580	65,344	16,802	23,688	35,797	5,638	877	109	170,716
27	Production: Non-Capacity Related Cost	29,920	13,602	17,723	166,189	49,496	65,127	88,821	14,264	2,223	363	447,727
28	Distribution: Demand Related Cost	19,423	2,536	4,458	83,653	15,385	25,346	63,410	2,210	490	159	217,070
29	Distribution: Customer Related Cost	3,186	171	528	6,873	854	1,211	4,320	119	39	16	17,317
30	Full Service MWH Sales	641,900	318,251	399,045	3,628,231	1,173,597	1,505,108	2,039,025	331,407	52,117	7,229	10,095,910
31	ROA MWH Sales	70,709	-	-	-	1,223,357	1,098,601	1,010,718	-	-	-	3,403,384
32	MWH Sales	712,609	318,251	399,045	3,628,231	2,396,954	2,603,709	3,049,743	331,407	52,117	7,229	13,499,294
33	Customers	1,338	23	78	1,595	39	97	936	5	6	4	4,122

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Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Net Plant**						
2	Production	2,444,872	1,224,544	578,031	7,056	626,815	8,427
3	Transmission	-	-	-	-	-	-
4	Distribution	11,482,091	6,914,188	3,003,225	211,893	1,331,210	21,574
5	General/Common/Intangible	875,513	550,014	210,797	7,251	106,264	1,187
6	Plant Purchased/Sold	0	0	0	0	0	0
7	Total Net Plant	14,802,477	8,688,746	3,792,053	226,200	2,064,289	31,188
8	**Working Capital**						
9	Total Current Assets	3,477,823	2,109,179	846,653	33,653	483,225	5,113
10	Total Current Liabilities	1,185,061	712,426	296,655	18,525	155,327	2,128
11	Total Working Capital	2,292,763	1,396,753	549,997	15,129	327,898	2,985
	Adjustments to Rate Base						
13	Additions to Rate Base	0	0	0	0	0	0
14	Deductions from Rate Base	72,670	25,230	11,800	177	34,114	1,348
15	Total Adjustments to Rate Base	(72,670)	(25,230)	(11,800)	(177)	(34,114)	(1,348)
16	**Total Rate Base**	**17,022,569**	**10,060,269**	**4,330,250**	**241,151**	**2,358,073**	**32,825**
17	**Production Expense**						
18	Fuel Expense	651,093	276,196	156,851	3,423	211,492	3,132
19	Purchased & Interchange Power Expense	1,411,341	629,236	338,213	6,475	431,171	6,245
20	Total Fuel and P&I Expense	2,062,434	905,432	495,064	9,899	642,663	9,377
21	Fossil O&M Exp	47,417	22,183	11,316	192	13,531	195
22	Nuclear O&M Exp	0	-	-	-	-	-
23	Hydro O&M Exp	13,774	6,498	3,284	54	3,883	56
23	Other Power Gen O&M Exp	67,599	33,858	15,982	195	17,331	233
24	Other Power Supply O&M Exp	4,602	2,305	1,088	13	1,180	16
25	Total Production O&M Expense	133,392	64,844	31,670	454	35,925	500
26	Total Production (Inc. Fuel and P&I) O&M Expense	2,195,826	970,276	526,733	10,352	678,588	9,877
27	**Transmission & Distribution Expense**						
28	Transmission Expense	703,549	335,866	167,595	2,235	195,494	2,359
29	Direct Assign Transmission	0	-	-	-	-	-
30	Distr Oper Exp	146,885	98,728	36,369	4,114	7,624	51
31	Distr Maint Exp	346,597	230,749	88,971	1,379	25,236	262
32	Total Transmission & Distribution O&M Expense	1,197,031	665,343	292,935	7,727	228,353	2,672
33	**Customer Related Expense**						
34	Customer Accounts Exp	49,808	35,772	8,910	267	4,850	9
35	Customer Service Exp	9,232	5,362	1,625	37	2,184	25
36	Other Customer Exp	17,683	13,004	4,369	178	132	0
37	Total Customer O&M Expense	76,723	54,138	14,904	482	7,167	34
38	**Admin & General Expense**	92,476	58,095	22,266	766	11,224	125
39	**Total O&M Expense**	**3,562,057**	**1,747,852**	**856,838**	**19,327**	**925,332**	**12,708**

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Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Net Plant**									
2	Production	1,224,544	1,224,544	355,234	222,797	578,031	236	1,512	5,308	7,056
3	Transmission	-	-	-	-	-	-	-	-	-
4	Distribution	6,914,188	6,914,188	1,921,800	1,081,425	3,003,225	7,345	186,196	18,353	211,893
5	General/Common/Intangible	550,014	550,014	135,500	75,296	210,797	341	5,449	1,461	7,251
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0
7	Total Net Plant	8,688,746	8,688,746	2,412,534	1,379,519	3,792,053	7,922	193,157	25,121	226,200
8	**Working Capital**									
9	Total Current Assets	2,109,179	2,109,179	540,676	305,977	846,653	1,406	26,175	6,073	33,653
10	Total Current Liabilities	712,426	712,426	189,607	107,049	296,655	621	15,930	1,973	18,525
11	Total Working Capital	1,396,753	1,396,753	351,069	198,928	549,997	784	10,245	4,100	15,129
	Adjustments to Rate Base									
13	Additions to Rate Base	0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base	25,230	25,230	7,393	4,407	11,800	21	80	77	177
15	Total Adjustments to Rate Base	(25,230)	(25,230)	(7,393)	(4,407)	(11,800)	(21)	(80)	(77)	(177)
16	**Total Rate Base**	**10,060,269**	**10,060,269**	**2,756,211**	**1,574,039**	**4,330,250**	**8,686**	**203,322**	**29,144**	**241,151**
17	**Production Expense**									
18	Fuel Expense	276,196	276,196	93,469	63,381	156,851	220	1,169	2,034	3,423
19	Purchased & Interchange Power Expense	629,236	629,236	203,302	134,911	338,213	381	2,064	4,030	6,475
20	Total Fuel and P&I Expense	905,432	905,432	296,771	198,293	495,064	602	3,233	6,064	9,899
21	Fossil O&M Exp	22,183	22,183	6,851	4,465	11,316	10	57	125	192
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	6,498	6,498	1,992	1,292	3,284	3	16	35	54
23	Other Power Gen O&M Exp	33,858	33,858	9,822	6,160	15,982	7	42	147	195
24	Other Power Supply O&M Exp	2,305	2,305	669	419	1,088	0	3	10	13
25	Total Production O&M Expense	64,844	64,844	19,333	12,336	31,670	20	117	317	454
26	Total Production (Inc. Fuel and P&I) O&M Expense	970,276	970,276	316,104	210,629	526,733	622	3,350	6,381	10,352
27	**Transmission & Distribution Expense**									
28	Transmission Expense	335,866	335,866	102,853	64,742	167,595	122	528	1,584	2,235
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	98,728	98,728	23,741	12,628	36,369	110	3,788	216	4,114
31	Distr Maint Exp	230,749	230,749	56,921	32,050	88,971	151	676	552	1,379
32	Total Transmission & Distribution O&M Expense	665,343	665,343	183,515	109,421	292,935	383	4,992	2,352	7,727
33	**Customer Related Expense**									
34	Customer Accounts Exp	35,772	35,772	6,494	2,416	8,910	14	199	54	267
35	Customer Service Exp	5,362	5,362	1,097	528	1,625	2	18	16	37
36	Other Customer Exp	13,004	13,004	3,745	623	4,369	12	151	15	178
37	Total Customer O&M Expense	54,138	54,138	11,337	3,567	14,904	29	368	85	482
38	**Admin & General Expense**	58,095	58,095	14,312	7,953	22,266	36	576	154	766
39	**Total O&M Expense**	**1,747,852**	**1,747,852**	**525,268**	**331,570**	**856,838**	**1,069**	**9,286**	**8,972**	**19,327**

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Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Net Plant**											
2	Production	45,011	17,387	24,281	245,309	58,025	83,366	132,645	17,749	2,742	301	626,815
3	Transmission	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	122,911	17,799	31,832	492,290	108,979	171,066	366,167	15,126	3,966	1,075	1,331,210
5	General/Common/Intangible	8,805	2,146	3,095	42,701	8,249	11,875	26,848	2,115	359	71	106,264
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0	0	0
7	Total Net Plant	176,727	37,333	59,208	780,300	175,252	266,306	525,659	34,990	7,067	1,447	2,064,289
8	**Working Capital**											
9	Total Current Assets	39,310	10,519	15,049	190,513	40,155	57,650	117,789	10,134	1,775	332	483,225
10	Total Current Liabilities	13,351	2,897	4,467	59,731	12,875	19,170	39,465	2,733	529	109	155,327
11	Total Working Capital	25,959	7,622	10,582	130,781	27,280	38,480	78,324	7,401	1,246	222	327,898
	Adjustments to Rate Base											
13	Additions to Rate Base	0	0	0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base	348	3,145	973	974	19,527	5,571	735	2,713	127	2	34,114
15	Total Adjustments to Rate Base	(348)	(3,145)	(973)	(974)	(19,527)	(5,571)	(735)	(2,713)	(127)	(2)	(34,114)
16	**Total Rate Base**	**202,338**	**41,810**	**68,817**	**910,108**	**183,005**	**299,215**	**603,248**	**39,678**	**8,186**	**1,667**	**2,358,073**
17	**Production Expense**											
18	Fuel Expense	13,653	6,532	8,332	76,905	23,978	31,212	42,851	6,796	1,077	157	211,492
19	Purchased & Interchange Power Expense	28,575	12,996	16,919	159,620	46,759	62,142	88,280	13,465	2,122	293	431,171
20	Total Fuel and P&I Expense	42,227	19,528	25,251	236,526	70,737	93,354	131,131	20,261	3,199	449	642,663
21	Fossil O&M Exp	927	395	534	5,145	1,339	1,871	2,831	416	65	8	13,531
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	267	113	153	1,481	381	535	813	118	19	2	3,883
23	Other Power Gen O&M Exp	1,245	481	671	6,783	1,604	2,305	3,668	491	76	8	17,331
24	Other Power Supply O&M Exp	85	33	46	462	109	157	250	33	5	1	1,180
25	Total Production O&M Expense	2,524	1,021	1,405	13,871	3,434	4,867	7,562	1,058	165	19	35,925
26	Total Production (Inc. Fuel and P&I) O&M Expense	44,751	20,549	26,655	250,396	74,171	98,221	138,693	21,319	3,364	469	678,588
27	**Transmission & Distribution Expense**											
28	Transmission Expense	14,042	5,610	7,698	75,889	19,631	26,983	38,739	5,876	888	139	195,494
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	876	36	61	3,524	213	256	2,614	29	6	8	7,624
31	Distr Maint Exp	2,549	177	344	10,857	1,085	1,862	8,144	151	43	24	25,236
32	Total Transmission & Distribution O&M Expense	17,467	5,824	8,103	90,270	20,928	29,102	49,497	6,056	937	170	228,353
33	**Customer Related Expense**											
34	Customer Accounts Exp	379	136	180	1,850	471	644	1,047	118	22	4	4,850
35	Customer Service Exp	118	51	64	588	386	420	494	53	8	1	2,184
36	Other Customer Exp	43	1	2	51	1	3	30	0	0	0	132
37	Total Customer O&M Expense	539	188	247	2,489	859	1,067	1,571	172	31	5	7,167
38	**Admin & General Expense**	930	227	327	4,510	871	1,254	2,836	223	38	8	11,224
39	**Total O&M Expense**	**63,687**	**26,788**	**35,332**	**347,665**	**96,829**	**129,643**	**192,596**	**27,770**	**4,370**	**652**	**925,332**

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Line No.	(a) Description		(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
	Input Allocation Schedules							
1	Energy @ Generation	100	100.000	42.863	24.128	0.542	31.975	0.492
2	Energy On-Peak @ Generation	101	100.000	40.306	25.541	0.416	33.350	0.387
3	Energy Off-Peak @ Generation	102	100.000	45.000	22.244	0.669	31.488	0.598
4	Energy On-Peak @ Generation Summer	103	100.000	41.291	25.797	0.348	32.168	0.397
5	Energy Off-Peak @ Generation Summer	104	100.000	45.185	22.454	0.598	31.116	0.648
6	Energy On-Peak @ Generation Non-Summer	105	100.000	39.736	25.392	0.456	34.034	0.382
7	Energy Off-Peak @ Generation Non-Summer	106	100.000	44.897	22.127	0.709	31.696	0.571
8	Energy Critical On-Peak @ Gen	107	100.000	43.335	26.395	0.271	29.718	0.281
9	Energy Summer Mid-Peak @ Gen	108	100.000	40.528	25.574	0.376	33.082	0.440
10	12CP Dmd @ Generation	120	100.000	47.739	23.821	0.318	27.787	0.335
11	4CP Dmd @ Generation	121	100.000	52.494	23.481	0.204	23.526	0.296
12	Class Peak @ Voltage 1	127	100.000	47.692	22.305	0.335	29.100	0.567
13	Production Revenue	141	100.000	45.892	24.324	0.381	29.413	(0.011)
14	Distribution Revenue	142	100.000	63.074	25.782	1.695	9.339	0.109
15	Total Rate Revenue	143	100.000	52.905	24.919	0.918	21.221	0.038
16	Billed Sales	150	100.000	37.294	21.545	0.471	40.232	0.457
17	Number Of Customers	160	100.000	87.485	12.010	0.289	0.215	0.001
18	Weighted Customer	170	100.000	61.132	27.235	0.048	11.547	0.038
			-					
	*Calculated Allocation Schedules							
19	4CP 75/0/25	220	100.000	50.086	23.643	0.289	25.638	0.345
20	Class Peak @ Voltage 2	122	100.000	50.430	23.586	0.355	25.030	0.600
21	Class Peak Voltage 1 Only	123	100.000	-	-	-	96.252	3.748
22	Class Peak Voltage 2 Only	124	100.000	-	-	-	95.052	4.948
23	Class Peak @ Voltage 1 excluding Voltage 2	125	100.000	50.792	23.755	0.357	24.813	0.283
24	Class Peak @ Voltage 3	230	100.000	54.042	25.275	0.380	20.242	0.061
25	Class Peak @ Voltage 4	231	100.000	67.809	31.714	0.477	-	-
26	Class Peak for Streetlighting	233	100.000	-	-	100.000	-	-
27	Class Peak @ Single Phase	235	100.000	67.809	31.714	0.477	-	-
28	Billed Sales - Primary	253	100.000	45.868	26.498	0.580	27.000	0.053
29	Customers - Residential	260	100.000	100.000	-	-	-	-
30	Customers - Commercial Secondary	261	100.000	-	100.000	-	-	-
31	Customers - Non-Primary	263	100.000	87.911	12.069	0.020	-	-
32	Customers - Non-Lighting	264	100.000	87.739	12.045	-	0.216	0.001
33	Customers - Commercial & Primary	267	100.000	-	98.236	-	1.758	0.006
34	Customer Count (CCC)	161	100.000	93.113	6.887	-	-	-
35	Customer Count (BCC)	162	100.000	-	91.649	4.783	3.555	0.012
36	PIS - HVD (Voltage 1)	301	100.000	50.694	23.710	0.356	24.700	0.541
37	PIS - HVD (Voltage 2)	302	100.000	50.368	23.557	0.354	25.170	0.551
38	PIS - HVD (Voltage 1) Substations	303	100.000	50.430	23.586	0.355	25.030	0.600
39	PIS - HVD (Voltage 2) Substations	304	100.000	41.662	19.486	0.293	37.378	1.181
40	PIS - OH LVD System	305	100.000	63.912	29.892	0.449	5.729	0.017
41	PIS - LVD Distribution	306	100.000	63.224	25.954	2.360	8.357	0.105
42	PIS- OH (LVD & HVD) Lines & Services	307	100.000	66.274	25.610	0.371	7.663	0.081
43	PIS- UG LVD Distribution	308	100.000	63.623	29.757	0.447	6.106	0.066
44	PIS- Total Distribution	309	100.000	61.498	25.637	2.088	10.612	0.165

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

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Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
	Input Allocation Schedules									
1	Energy @ Generation	42.863	42.863	14.352	9.776	24.128	0.036	0.188	0.318	0.542
2	Energy On-Peak @ Generation	40.306	40.306	15.495	10.045	25.541	0.017	0.109	0.290	0.416
3	Energy Off-Peak @ Generation	45.000	45.000	12.903	9.341	22.244	0.055	0.271	0.343	0.669
4	Energy On-Peak @ Generation Summer	41.291	41.291	15.724	10.073	25.797	0.008	0.074	0.265	0.348
5	Energy Off-Peak @ Generation Summer	45.185	45.185	13.055	9.399	22.454	0.046	0.235	0.318	0.598
6	Energy On-Peak @ Generation Non-Summer	39.736	39.736	15.362	10.030	25.392	0.023	0.130	0.304	0.456
7	Energy Off-Peak @ Generation Non-Summer	44.897	44.897	12.819	9.308	22.127	0.061	0.291	0.358	0.709
8	Energy Critical On-Peak @ Gen	43.335	43.335	16.254	10.142	26.395	0.001	0.026	0.244	0.271
9	Energy Summer Mid-Peak @ Gen	40.528	40.528	15.527	10.047	25.574	0.011	0.093	0.273	0.376
10	12CP Dmd @ Generation	47.739	47.739	14.619	9.202	23.821	0.017	0.075	0.225	0.318
11	4CP Dmd @ Generation	52.494	52.494	14.589	8.892	23.481	0.001	0.020	0.184	0.204
12	Class Peak @ Voltage 1	47.692	47.692	13.974	8.331	22.305	0.039	0.150	0.146	0.335
13	Production Revenue	45.892	45.892	14.787	9.537	24.324	0.020	0.102	0.259	0.381
14	Distribution Revenue	63.074	63.074	16.589	9.193	25.782	0.062	1.478	0.155	1.695
15	Total Rate Revenue	52.905	52.905	15.522	9.396	24.919	0.037	0.664	0.217	0.918
16	Billed Sales	37.294	37.294	12.539	9.007	21.545	0.031	0.164	0.276	0.471
17	Number Of Customers	87.485	87.485	10.952	1.058	12.010	0.020	0.245	0.024	0.289
18	Weighted Customer	61.132	61.132	22.049	5.186	27.235	0.048	-	-	0.048
	*Calculated Allocation Schedules									
19	4CP 75/0/25	50.086	50.086	14.530	9.113	23.643	0.010	0.062	0.217	0.289
20	Class Peak @ Voltage 2	50.430	50.430	14.777	8.809	23.586	0.041	0.159	0.154	0.355
21	Class Peak Voltage 1 Only	-	-	-	-	-	-	-	-	-
22	Class Peak Voltage 2 Only	-	-	-	-	-	-	-	-	-
23	Class Peak @ Voltage 1 excluding Voltage 2	50.792	50.792	14.883	8.873	23.755	0.041	0.160	0.155	0.357
24	Class Peak @ Voltage 3	54.042	54.042	15.835	9.440	25.275	0.044	0.170	0.165	0.380
25	Class Peak @ Voltage 4	67.809	67.809	19.869	11.845	31.714	0.055	0.214	0.208	0.477
26	Class Peak for Streetlighting	-	-	-	-	-	20.521	79.479	-	100.000
27	Class Peak @ Single Phase	67.809	67.809	19.869	11.845	31.714	0.055	0.214	0.208	0.477
28	Billed Sales - Primary	45.868	45.868	15.421	11.077	26.498	0.038	0.201	0.340	0.580
29	Customers - Residential	100.000	100.000	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	91.192	8.808	100.000	-	-	-	-
31	Customers - Non-Primary	87.911	87.911	11.006	1.063	12.069	0.020	-	-	0.020
32	Customers - Non-Lighting	87.739	87.739	10.984	1.061	12.045	-	-	-	-
33	Customers - Commercial & Primary	-	-	89.584	8.653	98.236	-	-	-	-
34	Customer Count (CCC)	93.113	93.113	6.824	0.063	6.887	-	-	-	-
35	Customer Count (BCC)	-	-	75.122	16.527	91.649	0.333	4.053	0.397	4.783
36	PIS - HVD (Voltage 1)	50.694	50.694	14.854	8.855	23.710	0.041	0.160	0.155	0.356
37	PIS - HVD (Voltage 2)	50.368	50.368	14.759	8.798	23.557	0.041	0.159	0.154	0.354
38	PIS - HVD (Voltage 1) Substations	50.430	50.430	14.777	8.809	23.586	0.041	0.159	0.154	0.355
39	PIS - HVD (Voltage 2) Substations	41.662	41.662	12.208	7.278	19.486	0.034	0.131	0.128	0.293
40	PIS - OH LVD System	63.912	63.912	18.727	11.165	29.892	0.052	0.202	0.196	0.449
41	PIS - LVD Distribution	63.224	63.224	16.754	9.200	25.954	0.070	2.135	0.154	2.360
42	PIS- OH (LVD & HVD) Lines & Services	66.274	66.274	16.300	9.310	25.610	0.043	0.167	0.162	0.371
43	PIS- UG LVD Distribution	63.623	63.623	18.643	11.114	29.757	0.052	0.201	0.195	0.447
44	PIS- Total Distribution	61.498	61.498	16.488	9.148	25.637	0.066	1.868	0.154	2.088

*Calculated allocation schedules may vary between product

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Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
	Input Allocation Schedules											
1	Energy @ Generation	2.090	0.978	1.286	11.820	3.356	4.580	6.617	1.055	0.168	0.024	31.975
2	Energy On-Peak @ Generation	2.374	0.994	1.338	12.857	3.475	4.653	6.424	1.043	0.156	0.034	33.350
3	Energy Off-Peak @ Generation	1.752	1.019	1.211	10.524	3.964	4.995	6.782	1.052	0.178	0.012	31.488
4	Energy On-Peak @ Generation Summer	2.338	0.948	1.273	12.534	3.230	4.351	6.387	0.937	0.140	0.031	32.168
5	Energy Off-Peak @ Generation Summer	1.748	0.990	1.194	10.528	3.801	4.777	6.904	0.996	0.167	0.011	31.116
6	Energy On-Peak @ Generation Non-Summer	2.395	1.021	1.377	13.044	3.617	4.829	6.446	1.105	0.166	0.035	34.034
7	Energy Off-Peak @ Generation Non-Summer	1.754	1.035	1.221	10.522	4.054	5.116	6.714	1.083	0.185	0.013	31.696
8	Energy Critical On-Peak @ Gen	2.184	0.840	1.152	11.671	2.890	3.985	5.989	0.874	0.116	0.015	29.718
9	Energy Summer Mid-Peak @ Gen	2.396	0.988	1.317	12.855	3.357	4.488	6.535	0.961	0.148	0.037	33.082
10	12CP Dmd @ Generation	1.996	0.797	1.094	10.787	2.790	3.835	5.506	0.835	0.126	0.020	27.787
11	4CP Dmd @ Generation	1.758	0.622	0.895	9.438	2.046	3.020	5.028	0.616	0.094	0.009	23.526
12	Class Peak @ Voltage 1	2.108	0.672	0.833	9.023	4.172	4.772	6.812	0.580	0.108	0.020	29.100
13	Production Revenue	2.097	0.937	1.187	10.985	3.133	4.158	5.947	0.823	0.129	0.019	29.413
14	Distribution Revenue	0.904	0.105	0.217	3.898	0.544	0.921	2.598	0.087	0.051	0.015	9.339
15	Total Rate Revenue	1.610	0.597	0.791	8.092	2.077	2.837	4.580	0.522	0.097	0.017	21.221
16	Billed Sales	2.124	0.948	1.189	10.813	7.144	7.760	9.089	0.988	0.155	0.022	40.232
17	Number Of Customers	0.070	0.001	0.004	0.083	0.002	0.005	0.049	0.000	0.000	0.000	0.215
18	Weighted Customer	2.780	0.067	0.386	4.960	0.158	0.320	2.825	0.019	0.020	0.012	11.547
		-	-	-	-	-	-	-	-	-	-	-
	*Calculated Allocation Schedules	-	-	-	-	-	-	-	-	-	-	-
19	4CP 75/0/25	1.841	0.711	0.993	10.034	2.373	3.410	5.425	0.726	0.112	0.012	25.638
20	Class Peak @ Voltage 2	2.223	-	0.881	9.541	-	5.046	7.203	-	0.115	0.021	25.030
21	Class Peak Voltage 1 Only	0.109	11.910	-	-	73.958	-	-	10.275	-	-	96.252
22	Class Peak Voltage 2 Only	1.437	-	13.649	-	-	78.189	-	-	1.777	-	95.052
23	Class Peak @ Voltage 1 excluding Voltage 2	2.152	0.716	-	9.610	4.443	-	7.255	0.617	-	0.021	24.813
24	Class Peak @ Voltage 3	2.276	-	-	10.225	-	-	7.719	-	-	0.022	20.242
25	Class Peak @ Voltage 4	-	-	-	-	-	-	-	-	-	-	-
26	Class Peak for Streetlighting	-	-	-	-	-	-	-	-	-	-	-
27	Class Peak @ Single Phase	-	-	-	-	-	-	-	-	-	-	-
28	Billed Sales - Primary	2.496	-	-	13.299	-	-	11.179	-	-	0.026	27.000
29	Customers - Residential	-	-	-	-	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	-	-	-	-	-	-	-	-	-
31	Customers - Non-Primary	-	-	-	-	-	-	-	-	-	-	-
32	Customers - Non-Lighting	0.070	0.001	0.004	0.083	0.002	0.005	0.049	0.000	0.000	0.000	0.216
33	Customers - Commercial & Primary	0.570	0.010	0.033	0.680	0.017	0.041	0.399	0.002	0.003	0.002	1.758
34	Customer Count (CCC)	-	-	-	-	-	-	-	-	-	-	-
35	Customer Count (BCC)	1.154	0.020	0.067	1.376	0.034	0.084	0.808	0.004	0.005	0.004	3.555
36	PIS - HVD (Voltage 1)	2.223	0.035	0.779	9.591	0.216	4.462	7.241	0.030	0.101	0.021	24.700
37	PIS - HVD (Voltage 2)	1.894	-	1.381	7.855	-	7.912	5.930	-	0.180	0.017	25.170
38	PIS - HVD (Voltage 1) Substations	2.223	-	0.881	9.541	-	5.046	7.203	-	0.115	0.021	25.030
39	PIS - HVD (Voltage 2) Substations	2.084	-	3.127	7.883	-	17.911	5.951	-	0.407	0.017	37.378
40	PIS - OH LVD System	0.644	-	-	2.894	-	-	2.185	-	-	0.006	5.729
41	PIS - LVD Distribution	0.848	0.157	0.100	3.276	0.960	0.451	2.413	0.133	0.011	0.007	8.357
42	PIS- OH (LVD & HVD) Lines & Services	0.763	0.031	0.105	3.374	0.194	0.602	2.547	0.027	0.014	0.007	7.663
43	PIS- UG LVD Distribution	0.545	0.153	0.006	2.440	0.948	0.036	1.842	0.132	0.001	0.005	6.106
44	PIS- Total Distribution	1.005	0.138	0.246	3.977	0.840	1.300	2.951	0.117	0.030	0.009	10.612

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(thousands of dollars)

Line No.	(a) Description		(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	*Calculated Allocation Schedules							
2	PIS- Distribution Services	310	100.000	93.751	6.249	-	-	-
3	PIS- Streetlighting Equipment	311	100.000	-	-	100.000	-	-
4	PIS- Line Equipment	312	100.000	66.641	31.168	0.468	1.717	0.005
5	PIS- Meters	313	100.000	61.132	27.235	0.048	11.547	0.038
6	PIS - General	315	100.000	100.000	0.000	0.000	0.000	0.000
7	Total PIS	316	100.000	59.413	25.146	1.657	13.587	0.197
8	Distribution Depreciation	317	100.000	64.975	24.420	2.623	7.879	0.102
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	318	100.000	39.111	18.292	0.275	41.242	1.080
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	319	100.000	50.710	23.717	0.356	24.758	0.459
11	PIS- LVD OH Lines & Services	320	100.000	68.863	25.969	0.375	4.779	0.014
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	321	100.000	-	-	-	96.252	3.748
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	322	100.000	52.423	24.518	0.369	22.407	0.282
14	CWIP	330	100.000	58.274	25.790	0.503	15.228	0.205
15	Rate Base- Total	390	100.000	59.100	25.438	1.417	13.853	0.193
16	Dist Op Expense (LVD) excl Sup & Eng	400	100.000	67.637	24.808	2.856	4.678	0.022
17	Dist Maint Expense (LVD) excl Sup & Eng	401	100.000	68.662	26.026	0.404	4.892	0.015
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	402	100.000	45.201	21.141	0.318	32.551	0.789
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	403	100.000	45.428	21.247	0.319	32.228	0.778
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	404	100.000	49.671	23.231	0.349	26.228	0.521
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	405	100.000	49.431	23.119	0.347	26.567	0.535
22	Total HVD Distribution O&M Expense	406	100.000	48.172	22.530	0.339	28.348	0.611
23	Total Distribution O&M Expense (excl. HVD)	407	100.000	68.391	25.642	1.172	4.780	0.016
24	Total Customer Accounts Expense (excl. Supv)	408	100.000	71.819	17.890	0.536	9.737	0.018
25	Total Customer Accounts & Service Expense	409	100.000	69.670	17.844	0.514	11.915	0.057
26	Pre Tax NOI	439	100.000	58.213	26.765	1.505	13.303	0.214
27	Depreciation & Amortization Expense	442	100.000	57.594	24.650	1.646	15.898	0.211
28	Non PSCR O&M Expense	443	100.000	63.631	24.392	0.904	10.951	0.122
29	Distribution Depreciation Expense	444	100.000	61.817	25.407	2.809	9.829	0.138
30	Gen/Comm/Int Depreciation Expense	445	100.000	62.822	24.077	0.828	12.137	0.136
31	Production Labor	500	100.000	50.086	23.643	0.289	25.638	0.345
32	Total Labor	502	100.000	62.822	24.077	0.828	12.137	0.136
33	50% O&M, 50% Net Plant	600	100.000	56.830	25.315	1.337	16.279	0.239
34	50/50 PIS & Labor	601	100.000	61.117	24.612	1.242	12.862	0.167

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

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Version 1
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(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	*Calculated Allocation Schedules									
2	PIS- Distribution Services	93.751	93.751	5.698	0.550	6.249	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	1.357	98.643	-	100.000
4	PIS- Line Equipment	66.641	66.641	19.527	11.641	31.168	0.054	0.210	0.204	0.468
5	PIS- Meters	61.132	61.132	22.049	5.186	27.235	0.048	-	-	0.048
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Total PIS	59.413	59.413	16.043	9.103	25.146	0.053	1.436	0.167	1.657
8	Distribution Depreciation	64.975	64.975	15.902	8.519	24.420	0.071	2.411	0.142	2.623
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	39.111	39.111	11.460	6.832	18.292	0.032	0.123	0.120	0.275
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	50.710	50.710	14.859	8.858	23.717	0.041	0.160	0.155	0.356
11	PIS- LVD OH Lines & Services	68.863	68.863	16.566	9.403	25.969	0.043	0.168	0.163	0.375
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	-	-	-	-	-	-	-	-	-
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	52.423	52.423	15.361	9.158	24.518	0.043	0.165	0.160	0.369
14	CWIP	58.274	58.274	16.189	9.601	25.790	0.035	0.278	0.189	0.503
15	Rate Base- Total	59.100	59.100	16.192	9.247	25.438	0.051	1.194	0.171	1.417
16	Dist Op Expense (LVD) excl Sup & Eng	67.637	67.637	16.208	8.601	24.808	0.076	2.633	0.147	2.856
17	Dist Maint Expense (LVD) excl Sup & Eng	68.662	68.662	16.685	9.342	26.026	0.044	0.200	0.160	0.404
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	45.201	45.201	13.245	7.896	21.141	0.037	0.143	0.138	0.318
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	45.428	45.428	13.311	7.936	21.247	0.037	0.143	0.139	0.319
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	49.671	49.671	14.554	8.677	23.231	0.040	0.157	0.152	0.349
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	49.431	49.431	14.484	8.635	23.119	0.040	0.156	0.151	0.347
22	Total HVD Distribution O&M Expense	48.172	48.172	14.115	8.415	22.530	0.039	0.152	0.147	0.339
23	Total Distribution O&M Expense (excl. HVD)	68.391	68.391	16.535	9.107	25.642	0.054	0.961	0.156	1.172
24	Total Customer Accounts Expense (excl. Supv)	71.819	71.819	13.039	4.851	17.890	0.028	0.400	0.108	0.536
25	Total Customer Accounts & Service Expense	69.670	69.670	12.858	4.986	17.844	0.028	0.369	0.118	0.514
26	Pre Tax NOI	58.213	58.213	16.985	9.780	26.765	0.045	1.315	0.145	1.505
27	Depreciation & Amortization Expense	57.594	57.594	15.743	8.907	24.650	0.047	1.426	0.174	1.646
28	Non PSCR O&M Expense	63.631	63.631	15.783	8.609	24.392	0.043	0.694	0.166	0.904
29	Distribution Depreciation Expense	61.817	61.817	16.627	8.779	25.407	0.075	2.591	0.143	2.809
30	Gen/Comm/Int Depreciation Expense	62.822	62.822	15.477	8.600	24.077	0.039	0.622	0.167	0.828
31	Production Labor	50.086	50.086	14.530	9.113	23.643	0.010	0.062	0.217	0.289
32	Total Labor	62.822	62.822	15.477	8.600	24.077	0.039	0.622	0.167	0.828
33	50% O&M, 50% Net Plant	56.830	56.830	15.997	9.317	25.315	0.049	1.102	0.186	1.337
34	50/50 PIS & Labor	61.117	61.117	15.760	8.852	24.612	0.046	1.029	0.167	1.242

*Calculated allocation schedules may vary between product

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Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	*Calculated Allocation Schedules											
2	PIS- Distribution Services	-	-	-	-	-	-	-	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	-	-	-	-	-	-
4	PIS- Line Equipment	0.193	-	-	0.868	-	-	0.655	-	-	0.002	1.717
5	PIS- Meters	2.780	0.067	0.386	4.960	0.158	0.320	2.825	0.019	0.020	0.012	11.547
6	PIS - General	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Total PIS	1.165	0.255	0.396	5.196	1.140	1.707	3.431	0.242	0.047	0.009	13.587
8	Distribution Depreciation	0.822	0.083	0.156	3.140	0.502	0.770	2.311	0.070	0.018	0.007	7.879
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	1.678	3.291	-	7.400	20.432	-	5.586	2.839	-	0.016	41.242
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	2.226	-	0.827	9.594	-	4.739	7.243	-	0.108	0.021	24.758
11	PIS- LVD OH Lines & Services	0.537	-	-	2.414	-	-	1.822	-	-	0.005	4.779
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	0.109	11.910	-	-	73.958	-	-	10.275	-	-	96.252
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	2.252	-	0.398	9.918	-	2.278	7.488	-	0.052	0.022	22.407
14	CWIP	1.226	0.300	0.479	6.073	1.105	1.893	3.787	0.300	0.056	0.010	15.228
15	Rate Base- Total	1.189	0.246	0.404	5.346	1.075	1.758	3.544	0.233	0.048	0.010	13.853
16	Dist Op Expense (LVD) excl Sup & Eng	0.562	0.014	0.023	2.248	0.080	0.066	1.665	0.011	0.002	0.005	4.678
17	Dist Maint Expense (LVD) excl Sup & Eng	0.577	0.001	0.007	2.455	0.003	0.006	1.836	0.000	0.000	0.005	4.892
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	1.961	1.609	0.375	8.552	9.991	2.151	6.456	1.388	0.049	0.019	32.551
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	1.971	1.547	0.389	8.595	9.603	2.231	6.489	1.334	0.051	0.019	32.228
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	2.209	-	1.094	9.398	-	6.269	7.095	-	0.143	0.020	26.228
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	2.205	-	1.156	9.352	-	6.622	7.060	-	0.151	0.020	26.567
22	Total HVD Distribution O&M Expense	2.131	0.491	0.909	9.114	3.050	5.209	6.881	0.424	0.118	0.020	28.348
23	Total Distribution O&M Expense (excl. HVD)	0.569	0.004	0.010	2.378	0.021	0.015	1.774	0.003	0.001	0.005	4.780
24	Total Customer Accounts Expense (excl. Supv)	0.760	0.272	0.361	3.714	0.945	1.292	2.103	0.238	0.044	0.008	9.737
25	Total Customer Accounts & Service Expense	0.840	0.317	0.414	4.129	1.452	1.801	2.610	0.291	0.052	0.009	11.915
26	Pre Tax NOI	1.449	0.438	0.535	5.449	0.926	1.408	3.065	(0.053)	0.066	0.019	13.303
27	Depreciation & Amortization Expense	1.334	0.351	0.521	6.209	1.341	1.957	3.771	0.345	0.059	0.010	15.898
28	Non PSCR O&M Expense	0.932	0.207	0.299	4.428	0.812	1.169	2.855	0.205	0.036	0.008	10.951
29	Distribution Depreciation Expense	1.048	0.118	0.223	3.784	0.702	1.068	2.755	0.097	0.026	0.008	9.829
30	Gen/Comm/Int Depreciation Expense	1.006	0.245	0.354	4.877	0.942	1.356	3.067	0.242	0.041	0.008	12.137
31	Production Labor	1.841	0.711	0.993	10.034	2.373	3.410	5.425	0.726	0.112	0.012	25.638
32	Total Labor	1.006	0.245	0.354	4.877	0.942	1.356	3.067	0.242	0.041	0.008	12.137
33	50% O&M, 50% Net Plant	1.309	0.349	0.515	6.142	1.482	2.156	3.911	0.342	0.062	0.011	16.279
34	50/50 PIS & Labor	1.085	0.250	0.375	5.037	1.041	1.531	3.249	0.242	0.044	0.009	12.862

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NET PLANT (SUMMARY)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Plant in Service**							
2	Production		3,943,866	1,975,333	932,432	11,382	1,011,126	13,594
3	Transmission		0	-	-	-	-	-
4	Distribution		15,272,067	9,391,991	3,915,234	318,908	1,620,692	25,244
5	General/Common/Intangible		1,445,142	908,048	347,828	11,964	175,342	1,959
6	Plant Purchased/Sold		0	0	0	0	0	0
7	Total Plant in Service		20,661,075	12,275,372	5,195,493	342,254	2,807,160	40,796
8	**Depreciation Reserve**							
9	Production		1,731,181	867,083	409,296	4,996	443,839	5,967
10	Transmission		0	-	-	-	-	-
11	Distribution		4,135,876	2,687,301	1,009,991	108,487	325,864	4,232
12	General/Common/Intangible		808,006	507,786	194,426	6,688	98,011	1,095
13	Total Depreciation Reserve		6,675,063	4,062,171	1,613,713	120,171	867,714	11,294
14	**Construction Work In Progress (CWIP)**							
15	Production		232,187	116,294	54,895	670	59,528	800
16	Transmission		-	-	-	-	-	-
17	Distribution		340,745	207,040	96,833	1,455	34,882	534
18	General/Common/Intangible		231,752	145,590	55,799	1,919	28,129	314
19	Total CWIP		804,684	468,924	207,527	4,045	122,539	1,649
20	**Future Use**							
21	Production	220	0	0	0	0	0	0
22	Distribution	127	5,155	2,459	1,150	17	1,500	29
23	Common/General	502	6,625	4,162	1,595	55	804	9
24	PHFFU Depreciation Reserve	127	0	0	0	0	0	0
25	Total Future Use		11,781	6,621	2,745	72	2,304	38
26	Total Net Plant		14,802,477	8,688,746	3,792,053	226,200	2,064,289	31,188

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PLANT IN SERVICE (SUMMARY)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Production Plant in Service**							
2	Production Plant in Service		3,943,866	1,975,333	932,432	11,382	1,011,126	13,594
3	Generation Step Ups		0	0	0	0	0	0
4	Total Production		3,943,866	1,975,333	932,432	11,382	1,011,126	13,594
5	**Distribution Plant in Service**							
6	Stations and Equipment		4,128,863	2,255,460	1,054,881	15,855	785,541	17,125
7	Overhead System		7,407,134	4,568,678	2,136,775	32,117	662,559	7,006
8	Underground System		1,369,068	878,443	410,849	6,175	72,813	788
9	Meters and Svc Drops		2,115,670	1,689,410	312,729	13,428	99,778	325
10	St Lgts and OPL		251,333	-	-	251,333	-	-
11	Total Distribution		15,272,067	9,391,991	3,915,234	318,908	1,620,692	25,244
12	**General/Common/Intangible Plant in Service**							
13	Total Gen/Comm/Int Plant		1,445,142	908,048	347,828	11,964	175,342	1,959
14	**Plant Purchased/Sold**		0	0	0	0	0	0
15	**Total Plant in Service**		20,661,075	12,275,372	5,195,493	342,254	2,807,160	40,796

PLANT IN SERVICE (PRODUCTION & TRANSMISSION)

1	**Production Plant in Service**							
2	Fossil (Production-Steam)	220	1,040,417	521,106	245,981	3,003	266,741	3,586
3	Demand Response	220	54,855	27,475	12,969	158	14,064	189
4	Total Hydro	220	869,815	435,658	205,647	2,510	223,003	2,998
5	Other Production	220	1,855,389	929,294	438,662	5,355	475,683	6,395
6	Production Batteries	220	123,390	61,801	29,173	356	31,635	425
7	Total Production Plant in Service		3,943,866	1,975,333	932,432	11,382	1,011,126	13,594

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PLANT IN SERVICE (DISTRIBUTION)

Line No.	(a) Description	(b) Alloc	(c) - Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Distribution Plant in Service**							
2	Distribution Land & ROW (360)							
3	HVD (Voltage 1) Substation Land & ROW	127	19,242	9,177	4,292	65	5,599	109
4	HVD (Voltage 1) Other Land & ROW	127	7,347	3,504	1,639	25	2,138	42
5	HVD (Voltage 2) Substation Land & ROW	122	20,535	10,356	4,843	73	5,140	123
6	HVD (Voltage 2) Other Land & ROW	122	84,307	42,516	19,885	299	21,102	506
7	LVD Land & ROW	230	71,451	38,613	18,059	271	14,463	44
8	Total Distribution Land & ROW		202,882	104,166	48,718	732	48,442	824
9	Distribution Substations & Equipment (361/362)							-
10	HVD (Voltage 1) Bulk Power Substations (Shared V2,3,4)	122	554,272	279,517	130,731	1,965	138,733	3,325
11	HVD (Voltage 1) Distribution Substations (Shared V3,4)	230	456,614	246,762	115,411	1,735	92,427	279
13	HVD (Voltage 2) Bulk Power Substations (Shared V2,3,4)	122	52,467	26,459	12,375	186	13,133	315
14	HVD (Voltage 2) Distribution Substations (Shared V3,4)	230	1,031,784	557,594	260,787	3,920	208,852	631
15	HVD (Voltage 2) Substations (V2 Only)	124	135,675	-	-	-	128,962	6,713
16	Total Distribution Substations & Equipment		2,363,010	1,110,333	519,304	7,805	709,349	16,218
17	Distribution Storage Battery Equipment (363)							
18	LVD V3 Distribution Batteries (Shared: V3,4)	230	4,897	2,646	1,238	19	991	3
19	Total Distribution Battery Equipment		4,897	2,646	1,238	19	991	3
20	Distribution Overhead System (364/365)							
21	HVD (Voltage 1) OH Lines (Shared V1,3,4)	125	9,788	4,971	2,325	35	2,429	28
24	HVD (Voltage 2) OH Lines (Shared V2,3,4)	122	499,903	252,099	117,907	1,772	125,125	2,999
25	HVD (Voltage 2) OH Lines (Shared V3,4)	230	564,352	304,986	142,642	2,144	114,235	345
26	HVD (Voltage 2) OH Lines (V2 Only)	124	34,322	-	-	-	32,624	1,698
27	LVD Primary (Multi-Phase)	230	1,762,321	952,389	445,433	6,695	356,726	1,077
28	LVD Primary (Single Phase)	235	3,420,976	2,319,730	1,084,940	16,307	-	-
29	LVD Secondary	231	1,043,186	707,374	330,839	4,973	-	-
30	Total Distribution Overhead System		7,407,134	4,568,678	2,136,775	32,117	662,559	7,006
31	Distribution Underground System (366/367)							
32	HVD (Voltage 1) UG Lines (V1 Only)	123	15,280	-	-	-	14,708	573
36	LVD Primary (Multi-Phase)	230	266,457	143,998	67,348	1,012	53,936	163
37	LVD Primary (Single Phase)	235	892,052	604,892	282,908	4,252	-	-
38	LVD Secondary	231	176,669	119,798	56,029	842	-	-
39	Total Distribution Underground System		1,369,068	878,443	410,849	6,175	72,813	788
40	Distribution Line Equipment (368)							
41	LVD Primary	230	132,193	71,440	33,412	502	26,758	81
42	LVD Secondary	231	1,425,880	966,875	452,208	6,797	-	-
43	Total Distribution Line Equipment		1,558,074	1,038,315	485,621	7,299	26,758	81
44	Distribution Services (369)							
45	Residential	260	1,161,184	1,161,184	-	-	-	-
46	Commercial & Industrial	261	77,397	-	77,397	-	-	-
47	Total Distribution Services		1,238,581	1,161,184	77,397	-	-	-

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PLANT IN SERVICE (DISTRIBUTION & GENERAL)

Line No.	(a) Description	(b) Alloc	(c) - Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	Distribution Metering Equipment (370)							
2	Metering Equipment	170	864,075	528,226	235,332	413	99,778	325
3	Total Distribution Metering Equipment		864,075	528,226	235,332	413	99,778	325
4	Distribution Installations on Customer Premises (371)							
5	Streetlighting Installations	DIR	13,014	-	-	13,014	-	-
6	Total Distribution Installations on Customer Premises		13,014	0	0	13,014	0	0
7	Distribution Streetlighting Equipment (373)							
8	Luminaires/Suspensions/Poles/Transformers	DIR	234,718	-	-	234,718	-	-
9	Underground Cable & Conduits	233	9,602	-	-	9,602	-	-
10	Photoelectric Switches	233	7,012	-	-	7,012	-	-
11	Total Distribution Streetlighting Equipment		251,333	-	-	251,333	-	-
12	Total Distribution Plant in Service		15,272,067	9,391,991	3,915,234	318,908	1,620,692	25,244
13	Total Distribution Plant in Service	309	15,272,067	9,391,991	3,915,234	318,908	1,620,692	25,244
14	**Electric Plant Purchased & Sold**	220	0	0	0	0	0	0
15	**General, Common & Intangible Plant in Service**							
16	MIMO EE/3.0 (U-20963 Order)	260	506	506	-	-	-	-
17	General, Common & Intangible	502	1,444,636	907,542	347,828	11,964	175,342	1,959
18	Total General, Common & Intangible Plant in Service		1,445,142	908,048	347,828	11,964	175,342	1,959

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DEPRECIATION RESERVE (SUMMARY)

Line No.	(a) Description	(b) Alloc	(c) - Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Production Depreciation Reserve**							
2	Production Depreciation Reserve		1,715,354	859,156	405,554	4,950	439,781	5,912
3	Generation Step Ups		0	0	0	0	0	0
4	Total Production Depreciation Reserve		1,731,181	867,083	409,296	4,996	443,839	5,967
5	**Distribution Depreciation Reserve**							
6	Stations and Equipment		835,547	474,667	222,002	3,337	132,724	2,817
7	Overhead System		1,910,866	1,197,604	560,121	8,419	143,569	1,152
8	Underground System		379,605	244,673	114,434	1,720	18,615	163
9	Meters and Svc Drops		919,053	770,357	113,435	4,205	30,956	101
10	St Lgts and OPL		90,807	-	-	90,807	-	-
11	Total Distribution Depreciation Reserve		4,135,876	2,687,301	1,009,991	108,487	325,864	4,232
12	**Total General, Common & Intangible Depreciation Reserve**		808,006	507,786	194,426	6,688	98,011	1,095
13	**Total Depreciation Reserve**		6,675,063	4,062,171	1,613,713	120,171	867,714	11,294

DEPRECIATION RESERVE (PRODUCTION & TRANSMISSION)

1	**Production Depreciation Reserve**							
2	Fossil (Production-Steam)	220	473,153	236,984	111,865	1,366	121,307	1,631
3	Demand Response	220	3,934	1,970	930	11	1,009	14
4	Hydro	220	716,067	358,651	169,297	2,067	183,585	2,468
5	Other Production	220	522,200	261,550	123,462	1,507	133,881	1,800
6	Production Batteries	220	15,827	7,927	3,742	46	4,058	55
7	Total Production Depreciation Reserve		1,731,181	867,083	409,296	4,996	443,839	5,967

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DEPRECIATION RESERVE (DISTRIBUTION)

Line No.	(a) Description	(b) Alloc	(c) - Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Distribution Depreciation Reserve**							
2	Distribution Land & Right of Way (360)							
3	HVD (Voltage 1) Substation Land & ROW	127	331	158	74	1	96	2
4	HVD (Voltage 1) Other Land & ROW	127	1,397	666	312	5	407	8
5	HVD (Voltage 2) Substation Land & ROW	122	353	178	83	1	88	2
6	HVD (Voltage 2) Other Land & ROW	122	16,036	8,087	3,782	57	4,014	96
7	LVD Land & ROW	230	14,490	7,831	3,662	55	2,933	9
8	Total Distribution Land & ROW Depreciation Reserve		32,607	16,920	7,913	119	7,538	117
9	Distribution Substations & Equipment (361/362)							
10	HVD (Voltage 1) Bulk Power Substations (Shared V2,3,4)	122	100,252	50,557	23,645	355	25,093	601
11	HVD (Voltage 1) Distribution Substations (Shared V3,4)	230	76,464	41,322	19,327	290	15,478	47
14	HVD (Voltage 1) Substations (V1 Only)	123	21,214	-	-	-	20,419	795
15	HVD (Voltage 2) Bulk Power Substations (Shared V2,3,4)	122	8,946	4,511	2,110	32	2,239	54
16	HVD (Voltage 2) Substations (V2 Only)	124	21,787	-	-	-	20,709	1,078
17	Total Distribution, Substations & Equipment Depreciation Reserve		394,354	185,933	86,961	1,307	117,477	2,676
17	Distribution Storage Battery Equipment (363)							
18	Batteries: LVD (Voltage 3)	230	3,737	2,020	945	14	756	2
19	Total Distribution Battery Equipment		3,737	2,020	945	14	756	2
20	Distribution Overhead System (364/365)		-	-	-	-	-	-
21	HVD (Voltage 1) OH Lines (Shared V1,3,4)	125	1,490	757	354	5	370	4
22	HVD (Voltage 1) OH Lines (Shared V3,4)	230	7,523	4,065	1,901	29	1,523	5
23	HVD (Voltage 1) OH Lines (V1 Only)	123	3,215	-	-	-	3,095	121
24	HVD (Voltage 2) OH Lines (Shared V2,3,4)	122	71,244	35,928	16,804	253	17,832	427
25	HVD (Voltage 2) OH Lines (Shared V3,4)	230	80,122	43,299	20,251	304	16,218	49
26	HVD (Voltage 2) OH Lines (V2 Only)	124	4,957	-	-	-	4,711	245
27	LVD	305	1,742,316	1,113,555	520,811	7,828	99,820	301
28	Total Distribution Overhead System Depreciation Reserve		1,910,866	1,197,604	560,121	8,419	143,569	1,152
29	Distribution Underground System (366/367)							
30	HVD (Voltage 1) UG Lines (V1 Only)	123	2,866	-	-	-	2,758	107
31	HVD (Voltage 2) UG Lines (Shared V2,3,4)	122	1,222	616	288	4	306	7
32	HVD (Voltage 2) UG Lines (Shared V3,4)	230	2,226	1,203	563	8	451	1
33	HVD (Voltage 2) UG Lines (V2 Only)	124	22	-	-	-	21	1
34	LVD	308	373,268	242,854	113,583	1,707	15,079	46
35	Total Distribution Underground System Depreciation Reserve		379,605	244,673	114,434	1,720	18,615	163
36	Distribution Line Equipment (368)							
37	Capacitors/Regulators/Transformers	312	404,848	269,794	126,183	1,897	6,953	21
38	Total Distribution Line Equipment Depreciation Reserve		404,848	269,794	126,183	1,897	6,953	21
39	Distribution Services (369)							
40	C&I and Residential Services	310	646,901	606,477	40,424	-	-	-
41	Total Distribution Services Depreciation Reserve		646,901	606,477	40,424	-	-	-

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DEPRECIATION RESERVE (DISTRIBUTION & GENERAL)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	Distribution Metering Equipment (370)							
2	Metering Equipment (Mass)	170	268,075	163,880	73,011	128	30,956	101
3	Total Distribution Metering Equpment Depreciation Reserve		268,075	163,880	73,011	128	30,956	101
4	Distribution Installations on Customer Premises (371)							
5	Streetlighting Installations	DIR	4,076	-	-	4,076	-	-
6	Total Distribution Installations on Customer Premises Depreciation Reserve		4,076	0	0	4,076	0	0
7	Distribution Streetlighting Equipment (373)							
8	Streetlighting Equipment	311	90,807	-	-	90,807	-	-
9	Total Distribution Streetlighting Depreciation Reserve		90,807	-	-	90,807	-	-
10	Total Distribution Depreciation Reserve		4,135,876	2,687,301	1,009,991	108,487	325,864	4,232
11	Total Distribution Depreciation Reserve	317	4,135,876	2,687,301	1,009,991	108,487	325,864	4,232
12	**General, Common & Intangible Depreciation Reserve**							
13	MIMO EE/3.0 (U-20963 Order)	260	497	497	-	-	-	-
14	General, Common & Intangible	502	807,509	507,289	194,426	6,688	98,011	1,095
15	Total General, Common & Intangible Depreciation Reserve		808,006	507,786	194,426	6,688	98,011	1,095

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CWIP

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Production CWIP**							
2	Production	220	232,187	116,294	54,895	670	59,528	800
3	Total Production CWIP		232,187	116,294	54,895	670	59,528	800
4	**Distribution CWIP**							
5	HVD (Voltage 1)	127	28,767	13,720	6,417	96	8,371	163
6	HVD (Voltage 2)	122	55,444	27,960	13,077	197	13,877	333
7	LVD Distribution	306	256,534	165,360	77,339	1,162	12,633	38
8	Total Distribution CWIP		340,745	207,040	96,833	1,455	34,882	534
9	**General/Common/Intangible CWIP**							
0	Plant Held for Future Use	502	0	0	0	0	0	0
10	General, Common & Intangible	502	231,752	145,590	55,799	1,919	28,129	314
11	Total General, Common & Intangible CWIP		231,752	145,590	55,799	1,919	28,129	314

WORKING CAPITAL

1	**Current Assets**							
2	Cash & Cash Equivalents	316	56,553	33,820	14,257	969	7,399	108
3	Accts Receivable	143	345,983	185,174	86,396	3,338	70,928	148
4	Material and Supplies	316	251,263	150,262	63,341	4,306	32,873	481
5	Fuel Stock	100	25,098	10,758	6,056	136	8,025	123
6	Deferred Taxes	316	283,834	169,740	71,552	4,864	37,134	543
7	Other Cur Assets	502	1,419,197	891,561	341,703	11,754	172,255	1,924
8	Deferred Debits	502	929,943	584,204	223,904	7,702	112,872	1,261
9	1/ Karn & Campbell Regulatory Assets	220	150,247	75,253	35,522	434	38,520	518
10	PMF Regulatory Asset	143	5,237	2,803	1,308	51	1,074	2
11	PMD Regulatory Asset	143	10,469	5,603	2,614	101	2,146	4
12	Total Current Assets		3,477,823	2,109,179	846,653	33,653	483,225	5,113
13	**Current Liabilities**							
14	Accounts Payable	316	612,195	366,109	154,329	10,491	80,094	1,171
15	Customer Deposits	143	26,644	14,260	6,653	257	5,462	11
16	Dividends Payable	316	29,263	17,500	7,377	501	3,828	56
17	Accrued Interest	316	73,846	44,162	18,616	1,265	9,661	141
18	Accrued Taxes - Federal	502	4,130	2,594	994	34	501	6
19	Accrued Taxes - State	601	1,310	805	323	16	165	2
20	Accrued Taxes - R&PP & Other	316	263,602	157,641	66,452	4,517	34,487	504
21	Other Current Liabilities	502	80,233	50,403	19,318	664	9,738	109
22	Deferred CR	502	93,839	58,951	22,594	777	11,390	127
23	Total Current Liabilities		1,185,061	712,426	296,655	18,525	155,327	2,128
24	**Total Working Capital**		2,292,763	1,396,753	549,997	15,129	327,898	2,985

ADJUSTMENTS TO RATE BASE

1	**Additions to Rate Base**							
2	XYZ	309	0	0	0	0	0	0
3	Total Additions		0	0	0	0	0	0
4	**Deductions to Rate Base**							
5	Customer Advances- Voltage 1 Customers	123	26,404	-	-	-	25,414	990
6	Customer Advances- Voltage 2 Customers	124	7,125	-	-	-	6,773	353
7	Customer Advances- LVD Customers	306	39,141	25,230	11,800	177	1,928	6
8	Total Deductions		72,670	25,230	11,800	177	34,114	1,348
9	**Total Adjustments to Rate Base**		(72,670)	(25,230)	(11,800)	(177)	(34,114)	(1,348)

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REVENUE

Line No.	(a) Description	(b) Alloc	(c) - Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Rate Revenue**							
2	Non PSCR Rate Revenue	DIR	2,607,063	1,647,111	681,268	33,414	243,330	1,939
3	Total Non PSCR Rate Revenue		2,607,063	1,647,111	681,268	33,414	243,330	1,939
4	PSCR Base Revenue	DIR	2,042,079	857,169	482,515	10,831	691,564	-
5	Total PSCR Rate Revenue		2,042,079	857,169	482,515	10,831	691,564	-
6	Total Rate Revenue		4,649,142	2,504,280	1,163,783	44,245	934,894	1,939
8	**Non-PSCR Rate Revenue Credits**							
9	450 Late Payment Charge Revenue	DIR	10,175	6,512	2,693	-	962	8
10	451 Miscellaneous Service & Reconnect Fees	253	1,128	517	299	7	305	1
11	454 Pole Rental Rev	307	12,736	8,441	3,262	47	976	10
12	454 Other Rents	316	2,036	1,260	520	41	212	3
13	456 Purchased Power Administrative Fees	100	752	322	181	4	240	4
14	Other Revenues	150	10,129	3,777	2,182	48	4,075	46
15	Job Work Revenue	410	1,859	1,241	472	21	124	1
16	LEDR & LTILRR: Production	DIR	252,264	115,032	58,799	1,256	75,993	1,184
17	LEDR & LTILRR: Delivery	390	14,367	8,837	3,720	245	1,541	23
18	Non PSCR Revenue Credits		305,445	145,940	72,129	1,669	84,428	1,279
20	PSCR Factor Revenue	DIR	408,717	171,560	96,574	2,168	138,415	-
21	Other Revenue- Large Load	415	0	-	-	-	-	-
22	Intersystem Sales	220	315,186	157,865	74,518	910	80,807	1,086
23	GSG and GI Market Price Revenue	DIR	12,965	-	-	-	-	12,965
24	PSCR Revenue Credits		736,868	329,425	171,092	3,077	219,222	14,051
25	Total Revenue Credits		1,042,314	475,365	243,221	4,746	303,650	15,331
26	Total Revenue		5,691,456	2,979,645	1,407,005	48,992	1,238,545	17,270

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PRODUCTION O&M (1)

Line No.	(a) Description	(b) Alloc	(c) - Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	Fuel and Purchased Power							
2	Mid-Peak Summer Fuel for Gen	108	103,289	41,861	26,415	388	34,170	454
3	On-Peak Winter Fuel for Gen	105	218,639	86,877	55,517	998	74,412	835
4	Off-Peak Summer Fuel for Gen	104	106,675	48,201	23,953	638	33,193	691
5	Off-Peak Winter Fuel for Gen	106	181,840	81,641	40,237	1,289	57,636	1,038
6	Critical Summer Peak Energy	107	40,649	17,615	10,729	110	12,080	114
7	Total Fuel Expense		651,093	276,196	156,851	3,423	211,492	3,132
	Purchased & Interchange Power Expense							
9	Mid-Peak Summer Purchased Power	108	160,693	65,126	41,095	604	53,161	707
10	On-Peak Winter Purchased Power	105	340,150	135,160	86,371	1,552	115,768	1,299
11	Off-Peak Summer Purchased Power	104	165,961	74,989	37,264	993	51,640	1,075
12	Off-Peak Winter Purchased Power	106	282,899	127,013	62,598	2,005	89,668	1,614
13	Critical Peak Summer Purchased Power	107	63,239	27,405	16,692	171	18,793	178
14	Direct Assign PPA- Large Load	DIR	0	-	-	-	-	-
15	Purchased Power Capacity: Other	220	398,398	199,543	94,192	1,150	102,141	1,373
16	Total Purchased & Interchange Power Expense		1,411,341	629,236	338,213	6,475	431,171	6,245
17	Total Fuel and Purchased & Interchange Power Expense		2,062,434	905,432	495,064	9,899	642,663	9,377

PRODUCTION O&M (2)

1	Fossil Plant O&M Expense							
2	Capacity Related Operations	220	22,846	11,442	5,401	66	5,857	79
3	Capacity Related Maintenance	220	2,888	1,446	683	8	740	10
4	Energy Related Operations	100	2,196	941	530	12	702	11
5	Energy Related Maintenance	100	12,866	5,515	3,104	70	4,114	63
6	Capacity Related Fuel Handling	220	0	0	0	0	0	0
7	Energy Related Fuel Handling	100	6,622	2,838	1,598	36	2,117	33
8	Total Fossil O&M Expense		47,417	22,183	11,316	192	13,531	195
9	Hydro Plant O&M Expense							
10	Capacity Related Operations	220	5,074	2,542	1,200	15	1,301	17
11	Capacity Related Maintenance	220	3,149	1,577	745	9	807	11
12	Energy Related Operations	100	1,123	481	271	6	359	6
13	Energy Related Maintenance	100	4,427	1,898	1,068	24	1,416	22
14	Total Hydro O&M Total		13,774	6,498	3,284	54	3,883	56
15	Other Power Generation O&M Expense							
16	Capacity Related Operations & Maintenance	220	67,599	33,858	15,982	195	17,331	233
17	Energy Related Operations & Maintenance	100	0	0	0	0	0	0
18	Total Other Power Gen O&M Expense		67,599	33,858	15,982	195	17,331	233
19	Other Power Supply Expense							
20	Capacity Related Operations & Maintenance	220	4,602	2,305	1,088	13	1,180	16
21	Energy Related Operations & Maintenance	100	0	0	0	0	0	0
22	Total Other Power Supply O&M Expense		4,602	2,305	1,088	13	1,180	16
23	Disposition of Allowances	220	0	0	0	0	0	0
24	**Total Production O&M (excluding Fuel and P&I)**		133,392	64,844	31,670	454	35,925	500
25	**Total Production O&M Expense**		2,195,826	970,276	526,733	10,352	678,588	9,877

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TRANSMISSION O&M

Line No.	(a) Description	(b) Alloc	(c) - Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Transmission O&M Expense**							
2	Transmission	120	703,549	335,866	167,595	2,235	195,494	2,359
3	Direct Assign Transmission	DIR	0	-	-	-	-	-
4	Total Transmission O&M Expense		703,549	335,866	167,595	2,235	195,494	2,359

DISTRIBUTION O&M

1	**Distribution Operation Expense**							
2	580 Supv & Engineering - Distribution (LVD)	400	31,652	21,408	7,852	904	1,481	7
3	580 Supv & Engineering - HVD (Voltage 1)	402	413	187	87	1	134	3
4	580 Supv & Engineering - HVD (Voltage 2)	404	778	386	181	3	204	4
5	581 Load Dispatch - Distribution	301	0	0	0	0	0	0
6	582 Station Expense - Distribution (LVD)	230	0	0	0	0	0	0
7	582 Station Expense - HVD (Voltage 1)	303	498	229	107	2	156	4
8	582 Station Expense - HVD (Voltage 2)	304	532	254	119	2	153	3
9	583 Overhead Expense - Distribution (LVD)	320	55,083	37,932	14,305	206	2,632	8
10	583 Overhead Expense - HVD (Voltage 1)	318	69	27	13	0	28	1
11	583 Overhead Expense - HVD (Voltage 2)	319	918	466	218	3	227	4
12	584 Underground Lines- Distribution (LVD)	308	12,148	7,903	3,696	56	491	1
13	584 Underground Lines- HVD (Voltage 1)	321	44	-	-	-	42	2
14	584 Underground Lines- HVD (Voltage 2)	322	54	28	13	0	12	0
15	585 Street Lighting & Signal System	311	1,998	-	-	1,998	-	-
16	586 Metering Expense	313	2,564	1,567	698	1	296	1
17	587 Customer Installations	160	7,081	6,195	850	20	15	0
18	588 Miscellaneous	400	29,596	20,018	7,342	845	1,384	6
19	589 Rents	309	3,458	2,127	887	72	367	6
20	Total Distribution Operation Expense		146,885	98,728	36,369	4,114	7,624	51
21	Distribution Maintenance Expense							
22	590 Supv & Engineering - Distribution (LVD)	401	3,609	2,478	939	15	177	1
23	590 Supv & Engineering - HVD (Voltage 1)	403	312	142	66	1	101	2
24	590 Supv & Engineering - HVD (Voltage 2)	405	588	291	136	2	156	3
25	591 Structures - Distribution (LVD)	230	0	0	0	0	0	0
26	591 Structures - HVD (Voltage 1)	303	413	190	89	1	130	3
27	591 Structures - HVD (Voltage 2)	304	441	211	99	1	127	3
28	592 Station Equipment - Distribution (LVD)	230	0	0	0	0	0	0
29	592 Station Equipment - HVD (Voltage 1)	303	9,516	4,381	2,049	31	2,984	71
30	592 Station Equipment - HVD (Voltage 2)	304	10,156	4,862	2,274	34	2,922	64
31	593 Overhead Lines - Distribution (LVD)	320	299,154	206,007	77,688	1,121	14,295	43
32	593 Overhead Lines - HVD (Voltage 1)	318	963	377	176	3	397	10
33	593 Overhead Lines - HVD (Voltage 2)	319	12,889	6,536	3,057	46	3,191	59
34	594 Underground Lines- Distribution (LVD)	308	2,622	1,706	798	12	106	0
35	594 Underground Lines- HVD (Voltage 1)	321	0	-	-	-	0	0
36	594 Underground Lines- HVD (Voltage 2)	322	0	0	0	0	0	0
37	595 Line Transformers	312	311	207	97	1	5	0
38	596 Street Lighting & Signal System	311	108	-	-	108	-	-
39	597 Meters	313	5,652	3,455	1,539	3	653	2
40	598 Miscellaneous	401	(138)	(94)	(36)	(1)	(7)	(0)
41	Total Distribution Maintenance Expense		346,597	230,749	88,971	1,379	25,236	262
42	**Total Distribution O&M Expense**		493,482	329,477	125,340	5,492	32,860	313

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CUSTOMER RELATED AND ADMINISTRATIVE & GENERAL EXPENSE

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Customer Accounts Expense**							
2	901 Supervision	408	2,401	1,725	430	13	234	0
3	902 Meter Reading	263	6,801	5,979	821	1	-	-
4	903 Rcrds & Collection	160	19,045	16,662	2,287	55	41	0
5	904 Uncollectibles	143	21,561	11,407	5,373	198	4,575	8
6	905 Misc Expenses	408	(0)	(0)	(0)	(0)	(0)	(0)
7	Total Customer Accounts		49,808	35,772	8,910	267	4,850	9
8	**Customer Services Expense**							
9	907 Supervision	160	1	1	0	0	0	0
10	908 Customer Assist	603	5,409	2,017	1,165	25	2,176	25
11	909 Info & Inst	160	3,822	3,344	459	11	8	0
12	910 Miscellaneous	160	0	0	0	0	0	0
13	Total Customer Services		9,232	5,362	1,625	37	2,184	25
14	**Other Expense**							
15	911-916 Sales Expense	160	90	79	11	0	0	0
16	Customer Contact Center (CCC)	161	13,881	12,925	956	-	-	-
17	Business Customer Care (BCC)	162	3,712	-	3,402	178	132	0
18	Multi Acct Mgmt Project (Formerly C&I Online Acct Mgmt)	502	0	0	0	0	0	0
19	Total Other Expense		17,683	13,004	4,369	178	132	0
20	**Administrative & General Expense**							
21	Production	500	23,450	11,745	5,544	68	6,012	81
22	HV Distribution	406	4,912	2,366	1,107	17	1,393	30
23	Distribution	407	53,531	36,610	13,726	627	2,559	9
24	Customer	409	10,583	7,373	1,888	54	1,261	6
25	Total Administrative & General Expense		92,476	58,095	22,266	766	11,224	125
26	**Total O&M Expense (excluding PSCR Expense)**		796,074	506,554	194,179	7,194	87,175	972
27	Test Year Other O&M Expense	443	0	-	0	0	0	0
27	**Total O&M Expense**		3,562,057	1,747,852	856,838	19,327	925,332	12,708

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DEPRECIATION EXPENSE (SUMMARY)

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Production Depreciation Expense**							
2	Production Depreciation Expense		310,355	155,445	73,376	896	79,569	1,070
3	Total Production		318,691	159,620	75,347	920	81,706	1,098
4	**Distribution**							
5	Stations and Equipment		96,964	53,739	25,134	378	17,335	378
6	Overhead System		215,625	133,357	62,371	937	18,768	192
7	Underground System		30,961	19,767	9,245	139	1,787	23
8	Meters and Svc Drops		89,024	66,979	15,797	579	5,650	18
9	St Lgts and OPL		10,413	-	-	10,413	-	-
10	Total Distribution		442,986	273,842	112,548	12,445	43,541	610
11	**General/Common/Intangible**							
12	General, Common & Intangible		68,184	42,835	16,417	565	8,276	92
13	Test Year Gen/Comm/Int Change	445	0	-	-	-	-	-
14	Total General/Common/Intangible Dep Expense		68,184	42,835	16,417	565	8,276	92
15	**Other Amortization Expense**		24,653	15,854	6,329	136	2,329	6
16	**Total Depreciation & Amortization Expense**		854,516	492,151	210,641	14,065	135,851	1,807

DEPRECIATION EXPENSE (PRODUCTION & TRANSMISSION)

1	**Production Depreciation Expense**							
2	Fossil (Production-Steam)	220	198,059	99,200	46,826	572	50,778	683
3	Demand Response	220	3,016	1,511	713	9	773	10
4	Hydro	220	64,363	32,237	15,217	186	16,501	222
5	Other Production	220	44,917	22,497	10,620	130	11,516	155
6	Production Batteries	220	8,336	4,175	1,971	24	2,137	29
7	Total Production Depreciation Expense		318,691	159,620	75,347	920	81,706	1,098

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DEPRECIATION EXPENSE (DISTRIBUTION & GENERAL)

Line No.	(a) Description	(b) Alloc	(c) - Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Distribution Depreciation Expense**							
2	Distribution Land & Right of Way (360)		-	-	-	-	-	-
3	HVD (Voltage 1) Substation Land & ROW	127	50	24	11	0	14	0
4	HVD (Voltage 1) Other Land & ROW	127	92	44	21	0	27	1
5	HVD (Voltage 2) Substation Land & ROW	122	53	27	12	0	13	0
6	HVD (Voltage 2) Other Land & ROW	122	1,057	533	249	4	264	6
7	LVD Land & ROW	230	970	524	245	4	196	1
8	Total Distribution Land & ROW Depreciation Expense		2,221	1,151	538	8	515	8
9	Distribution Substations & Equipment (361/362)							
10	HVD (Voltage 1) Bulk Power Substations (Shared V2,3,4)	122	12,287	6,196	2,898	44	3,075	74
11	HVD (Voltage 1) Distribution Substations (Shared V3,4)	230	10,289	5,560	2,600	39	2,083	6
12	HVD (Voltage 1) Substations (V1 Only)	123	3,012	-	-	-	2,899	113
13	HVD (Voltage 2) Bulk Power Substations (Shared V2,3,4)	122	1,173	592	277	4	294	7
14	HVD (Voltage 2) Distribution Substations (Shared V3,4)	124	23,494	12,697	5,938	89	4,756	14
15	HVD (Voltage 2) Substations (V2 Only)	124	3,093	-	-	-	2,940	153
16	Total Distribution Substations & Equipment Depreciation Expense		53,348	25,045	11,714	176	16,046	367
			-	-	-	-	-	-
17	Distribution Storage Battery Equipment (363)		-	-	-	-	-	-
18	Batteries: LVD (Voltage 3)	230	338	183	86	1	68	0
19	Total Distribution Battery Equipment		338	183	86	1	68	0
20	Distribution Overhead System (364/365)							
21	HVD (Voltage 1) OH Lines (Shared V1,3,4)	125	254	129	60	1	63	1
22	HVD (Voltage 1) OH Lines (Shared V3,4)	230	1,317	712	333	5	267	1
23	HVD (Voltage 1) OH Lines (V1 Only)	123	604	-	-	-	582	23
24	HVD (Voltage 2) OH Lines (Shared V2,3,4)	122	13,377	6,746	3,155	47	3,348	80
25	HVD (Voltage 2) OH Lines (Shared V3,4)	230	15,269	8,252	3,859	58	3,091	9
26	HVD (Voltage 2) OH Lines (V2 Only)	124	929	-	-	-	883	46
27	LVD	305	183,875	117,519	54,964	826	10,535	32
28	Total Distribution Overhead Depreciation Expense		215,625	133,357	62,371	937	18,768	192
29	Distribution Underground System (366/367)							
30	HVD (Voltage 1) UG Lines (V1 Only)	123	464	-	-	-	446	17
31	HVD (Voltage 2) UG Lines (Shared V2,3,4)	122	211	106	50	1	53	1
32	HVD (Voltage 2) UG Lines (Shared V3,4)	230	378	204	95	1	76	0
33	HVD (Voltage 2) UG Lines (V2 Only)	124	4	-	-	-	3	0
34	LVD	308	29,905	19,457	9,100	137	1,208	4
35	Total Distribution Underground Depreciation Expense		30,961	19,767	9,245	139	1,787	23
36	Distribution Line Equipment (368)							
37	Line Equipment	312	41,056	27,360	12,796	192	705	2
38	Total Distribution Line Equipment Depreciation Expense		41,056	27,360	12,796	192	705	2
39	Distribution Services (369)							
40	Overhead & Underground Services	310	39,536	37,065	2,471	-	-	-
41	Total Distribution Services Depreciation Expense		39,536	37,065	2,471	-	-	-

Projected 12-Month Period Ending April 30, 2028
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

DEPRECIATION EXPENSE (DISTRIBUTION & GENERAL)

Line No.	(a) Description	(b) Alloc	(c) - Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	**Distribution (cont.)**							
2	Distribution Metering Equipment (370)		-	-	-	-	-	-
3	Metering Equipment	170	48,933	29,914	13,327	23	5,650	18
4	Total Distribution Metering Equipment Depreciation Expense		48,933	29,914	13,327	23	5,650	18
5	Distribution Installations on Customer Premises (371)		-	-	-	-	-	-
6	Streetlighting Installations	DIR	555	-	-	555	-	-
7	Total Distribution Installations on Customer Premises		555	0	0	555	0	0
8	Distribution Streetlighting Equipment Depreciation Expense (373)	311	10,413	-	-	10,413	-	-
9	**Total Distribution Depreciation Expense**		442,986	273,842	112,548	12,445	43,541	610
10	**General/Common/Intangible**							
11	MIMO EE/3.0 (U-20963 Order)	502	18	11	4	0	2	0
12	General, Common & Intangible	502	68,166	42,823	16,413	565	8,274	92
13	Total Gen/Comm/Int Depreciation Expense		68,184	42,835	16,417	565	8,276	92
14	**Other Amortization**							
15	PMF Amortization	143	2,445	1,309	611	24	501	1
16	PMD Amortization	143	4,876	2,610	1,218	47	1,000	2
17	Storm Deferral Amortization	320	17,332	11,936	4,501	65	828	3
19	Total Other Amortization Expense		24,653	15,854	6,329	136	2,329	6
20	**Total Depreciation & Amortization Expense**		854,516	492,151	210,641	14,065	135,851	1,807

Projected 12-Month Period Ending April 30, 2028
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

TAX

Line No.	(a) Description	(b) Alloc	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(f) Total Lighting & Unmetered	(g) Total Primary	(h) Rate GSG
1	City Income Tax	150	1,182	441	255	6	476	5
2	State Income Tax	439	36,041	20,980	9,646	542	4,794	77
	RP&P Tax							
4	R&PP Taxes - Prod	220	65,050	32,581	15,379	188	16,677	224
5	R&PP Taxes - HVD (Voltage 1)	301	20,184	9,097	4,255	64	6,606	162
6	R&PP Taxes - HVD (Voltage 2)	302	38,902	19,177	8,969	135	10,408	213
7	R&PP Taxes - LVD	306	151,360	97,566	45,632	686	7,454	23
8	R&PP Taxes - PHFFU	316	80	50	21	2	8	0
9	R&PP Taxes -General, Common & Intangible	502	26,224	16,474	6,314	217	3,183	36
10	Total R&PP Taxes		301,800	174,945	80,569	1,291	44,337	658
11	Payroll and Miscellaneous Tax							
12	Payroll Related Taxes	502	27,447	17,243	6,608	227	3,331	37
13	Total Payroll/Miscellaneous Taxes		27,447	17,243	6,608	227	3,331	37
14	Other Taxes	150	13,294	4,958	2,864	63	5,348	61
15	Total Other Taxes		379,764	218,567	99,943	2,129	58,287	838
16	Federal Income Tax	439	77,450	45,086	20,730	1,166	10,303	166
17	Total Taxes Other Than Income		343,723	197,586	90,297	1,587	53,493	761
18	Total Income Taxes		113,491	66,067	30,376	1,708	15,097	243
19	**Total Taxes**		457,214	263,653	120,673	3,295	68,590	1,004

INCOME STATEMENT ADJUSTMENTS

1	**Other Adjustments to the Income Statement**							
2	AFUDC	330	17,040	9,930	4,395	86	2,595	35
3	**Total Other Adjustments**		17,040	9,930	4,395	86	2,595	35

ADDITIONAL REVENUE REQUIREMENTS

1	**Additional Revenue Requirements**							
2	Return On - Campbell Regulatory Asset	220	70,954	35,538	16,775	205	18,191	245
3	0	320	0	0	0	0	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Alternative Meter Allocation

Case No. U-22070
Exhibit No.: A-76 (EAD-2)
Page: 1 of 1
Witness: EADavis
Date: June 2026

Line	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary & GSG
1	Proposed Rate Design Revenue (PRDR) with Alternative Meter Allocator ($000)	**$ 5,104,976**	**$ 2,777,901**	**$ 1,262,210**	**$ 49,208**	**$ 1,015,656**
2	Proposed PRDR (EAD-1) ($000)	$ 5,104,976	$ 2,777,169	$ 1,263,865	$ 49,146	$ 1,014,796
3	Difference	$ -	$ 732	$ (1,655)	$ 62	$ 861
4	Percent Difference	0.0%	0.0%	-0.1%	0.1%	0.1%
5	Weighted Customer Allocator (170)	100.0%	61.1%	27.2%	0.0%	11.6%
6	Alternative Meter Allocator (171)	100.0%	61.7%	25.9%	0.1%	12.3%
				Source		
7	Demand Weighting	17%		U-21870 Direct Testimony of Caroline Palmer page 9		
8	Energy Weighting	36%		U-21870 Direct Testimony of Caroline Palmer page 9		
9	Customer Weighting	47%		U-21870 Direct Testimony of Caroline Palmer page 9		
10	Standard 1PH Smart Meter	**$ 127**		Meter Cost Study		
11	1PH Non-Transmitting Meter	**$ 62**		Meter Technical Services		
12	Smart Meter "Premium"	$ 65		Line 6- Line 7		
13	Number of AMI Meters	**1,960,126**		Meter Cost Study		
14	Cost of AMI "Premium" ($000)	$ 126,918,159	15%	Line 8 x Line 9		
15	Other Meter Costs ($000)	$ 737,156,640	85%	(EAD-WP 68 column (c) Line 1 x 1000) - Line 10		

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
SRM Calculation
Projected 12-Month Period Ending April 30, 2028
(thousands of dollars)

Case No. U-22070
Exhibit No.: A-77 (EAD-3)
Page: 1 of 1
Witness: EADavis
Date: June 2026

Line No.	(a) Description	(b) Total Electric ($000)	(c) Capacity Charge	(d) Formula
1	Total Production Related Cost	$ 2,662,835		
2	Non-Capacity Related Cost:			
3	Fuel Expense	$ 651,093		
4	Purchased & Interchanged	1,012,943		
5	Energy Related Other O&M Expense	27,235		
6	PSCR Revenue Credits	(736,868)		
7	Non-PSCR Revenue Credits	(260,660)		
8	Transmission Expense	703,549		
9	Total Non-Capacity Related Cost	$ 1,397,291		Σ Lines 3:8
10	Total Capacity Related Cost	$ 1,265,544		Line 1 - Line 9
11	Offsets:			
12	Energy Market Sales	**1,229,064**		
13	Off-System Energy Sales	**-1,000**		
14	Ancillary Service Sales	**9,000**		
15	Bilateral Energy Sales	**0**		
16	Total Revenue	$ 1,237,064		Σ Lines 12:15
17	Related Fuel Cost	**648,553**		
18	Total Revenue Less Fuel Cost	$ 588,511		Line 16 - Line 17
19	Net Capacity Cost	$ 677,033		Line 10 - Line 18
20	Capacity Charge Demand (MW)		**9,190**	
21	Capacity Charge ($/MW-Day)		$201.84	[(Line 19 x 1,000) ÷ Line 20] ÷ 365

Source:
Lines 1-8: Exhibit A-16 (EAD-1) Schedule F-1
Lines 12-15,17, 20 Company witness Joshua Hahn

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
SOC Calculation
(thousands of dollars)

Case No. U-22070
Exhibit No.: A-78 (EAD-4)
Page: 1 of 1
Witness: EADavis
Date: June 2026

Line	(a) Description	(b) Total Voltage 1	(c) Total Voltage 2	(d) Rate GPD Voltage 1	(e) Rate GPTU Voltage 1	(f) Rate EIP Voltage 1	(g) Rate GPD Voltage 2	(h) Rate GPTU Voltage 2	(i) Rate EIP Voltage 2
1	Plant in Service	$ 128,143	$ 131,423	$ 98,573	$ 15,875	$ 13,695	$ 109,766	$ 19,161	$ 2,495
2	Depreciation Reserve	(20,414)	(20,958)	(15,703)	(2,529)	(2,182)	(17,504)	(3,056)	(398)
3	Net Plant	107,729	110,465	82,870	13,346	11,513	92,262	16,106	2,097
4	Working Capital	5,929	5,474	4,295	856	779	4,434	902	137
5	CWIP (HV Distribution)	1,196	2,729	922	146	128	2,306	372	51
6	Substation Rate Base	$ 114,854	$ 118,668	$ 88,086	$ 14,347	$ 12,420	$ 99,002	$ 17,380	$ 2,286
7	Pre-Tax Return	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%
8	Pre-Tax Return ($)	$ 9,359	$ 9,670	$ 7,178	$ 1,169	$ 1,012	$ 8,068	$ 1,416	$ 186
9	Depreciation Expense	2,899	2,969	2,230	359	310	2,480	433	56
10	O&M Expense	1,159	1,188	892	144	124	992	173	23
11	Other Taxes	3,632	2,253	2,850	406	376	1,890	310	53
12	Revenue Credits	(736)	(551)	(581)	(78)	(78)	(467)	(72)	(12)
13	Total Revenue Requirement	$ 16,313	$ 15,529	$ 12,569	$ 2,000	$ 1,745	$ 12,962	$ 2,261	$ 307
14	Max Demand (MW)	6,507	7,201	4,868	888	752	5,514	1,308	379
15	Substation Ownership Credit ($/kW)	**$ 2.5068**	**$ 2.1565**	**$ 2.5821**	**$ 2.2518**	**$ 2.3207**	**$ 2.3508**	**$ 1.7281**	**$ 0.8087**

Source: Exhibit A-16 (EAD-1) Schedule F-1
WP-MCG-3 and 4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Allocation of Surcharges
(thousands of dollars)

Case No. U-22070
Exhibit No.: A-79 (EAD-5)
Page: 1 of 3
Witness: EADavis
Date: June 2026

Line No	Description	Total Electric	Source
1	Electric Rate Case ("ERC") Deferral	**$ 25,008**	**Exhibit HLP-60**
2	Investment Recovery Mechanism ("IRM")		
3	**IRM 12 Mo Ending 4/30/2028**	**$ 20,235**	**Exhibit HJM-1**
4	**IRM 12 Mo Ending 4/30/2029**	**$ 57,644**	Exhibit HJM-1

	Description	Alloc	Total Electric	Total Residential	Total Commercial Secondary	Total Lighting & Unmetered	Total Primary	Rate GSG
			(a)	(c)	(d)	(f)	(e)	(g)
5	**ERC Deferral Surcharge**							
6	1/ Distribution: Demand Related Cost		2,172,171	1,341,987	573,146	36,915	217,070	$ 3,054
7	1/ Distribution: Customer Related Cost		269,970	200,586	50,304	1,644	17,317	$ 119
8	Total Distribution Costs		2,442,141	$ 1,542,573	$ 623,450	$ 38,559	$ 234,386	$ 3,173
9	Total Distribution Costs (Allocator)		1.00000	0.63165	0.2553	0.0158	0.0960	0.0013
10	Allocation of ERC Surcharge		25,008	$ 15,796	$ 6,384	$ 395	$ 2,400	$ 32
11	**Allocation of IRM 12 Mo Ending 4/30/2028**		20,235	$ 12,781	$ 5,166	$ 319	$ 1,942	$ 26
12	**Allocation of IRM 12 Mo Ending 4/30/2029**		57,644	$ 36,411	$ 14,716	$ 910	$ 5,532	$ 75

Source:
Exhibit A-16 (EAD-1)

Line No	Description	Alloc	Rate Residential	Total Residential	Rate GS	Rate GSD	Total Commercial Secondary	Rate GML	Rate UUL	Rate GU	Total Lighting & Unmetered
			(a)	(b)	(c)	(d)	(e)	(l)	(m)	(n)	(o)
5	**ERC Deferral Surcharge**										
6	1/ Distribution: Demand Related Cost		1,341,987	1,341,987	363,344	209,802	573,146	1,364	31,851	3,701	36,915
7	1/ Distribution: Customer Related Cost		200,586	200,586	40,001	10,303	50,304	84	1,463	97	1,644
8	Total Distribution Costs		$ 1,542,573	$ 1,542,573	$403,345	$ 220,105	$ 623,450	$ 1,448	$ 33,314	$ 3,797	$ 38,559
9	Total Distribution Costs (Allocator)		0.6316	0.6316	0.1652	0.0901	0.2553	0.00059	0.01364	0.00155	0.01579
10	Allocation of ERC Surcharge		$ 15,796	$ 15,796	$ 4,130	$ 2,254	$ 6,384	$ 15	$ 341	$ 39	$ 395
11	**Allocation of IRM 12 Mo Ending 4/30/2028**		$ 12,781	$ 12,781	$ 3,342	$ 1,824	$ 5,166	$ 12	$ 276	$ 31	$ 319
12	**Allocation of IRM 12 Mo Ending 4/30/2029**		$ 36,411	$ 36,411	$ 9,521	$ 5,195	$ 14,716	$ 34	$ 786	$ 90	$ 910

Source:
Exhibit A-16 (EAD-1)

Line No	Description	Alloc	Rate GP	Rate GPTU Vlt 1	Rate GPTU Vlt 2	Rate GPTU Vlt 3	Rate GPD Vlt 1	Rate GPD Vlt 2	Rate GPD Vlt 3	Rate EIP Vlt 1	Rate EIP Vlt 2	Rate EIP Vlt 3	Total Primary
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
5	**ERC Deferral Surcharge**												
6	1/ Distribution: Demand Related Cost		19,423	2,536	4,458	83,653	15,385	25,346	63,410	2,210	490	159	217,070
7	1/ Distribution: Customer Related Cost		3,186	171	528	6,873	854	1,211	4,320	119	39	16	17,317
8	Total Distribution Costs		$ 22,609	$ 2,707	$ 4,986	$ 90,526	$ 16,239	$ 26,557	$ 67,730	$ 2,329	$ 530	$ 175	$ 234,386
9	Total Distribution Costs (Allocator)		0.00926	0.00111	0.00204	0.03707	0.00665	0.01087	0.02773	0.00095	0.00022	0.00007	0.09598
10	Allocation of ERC Surcharge		$ 232	$ 28	$ 51	$ 927	$ 166	$ 272	$ 694	$ 24	$ 5	$ 2	$ 2,400
11	**Allocation of IRM 12 Mo Ending 4/30/2028**		$ 187	$ 22	$ 41	$ 750	$ 135	$ 220	$ 561	$ 19	$ 4	$ 1	$ 1,942
12	**Allocation of IRM 12 Mo Ending 4/30/2029**		$ 534	$ 64	$ 118	$ 2,137	$ 383	$ 627	$ 1,599	$ 55	$ 13	$ 4	$ 5,532

Source:
Exhibit A-16 (EAD-1)

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Rate Base**	15,023,435	8,528,549	3,737,295	212,235	2,517,885	27,471
2	**Revenue**						
3	Total Rate Revenue	5,057,111	2,347,060	1,138,314	39,799	1,530,460	1,478
4	Total Revenue Credits	1,062,868	391,232	206,649	4,033	442,529	18,425
5	Total Revenue	6,119,980	2,738,292	1,344,963	43,832	1,972,989	19,904
6	**Expenses:**						
7	Fuel and P&I Expense	2,166,028	780,398	427,572	7,981	941,490	8,587
8	Transmission Expense	758,515	300,835	156,520	2,064	296,705	2,391
9	Other O & M Expense	786,210	490,789	183,681	6,296	104,600	844
10	Depreciation & Amortization Expense	803,119	431,196	188,624	13,553	168,147	1,599
11	Other Taxes	375,732	198,874	94,619	1,994	79,324	921
12	Federal Income Taxes	151,415	65,987	36,174	1,470	47,100	684
13	Total Expenses	5,041,018	2,268,079	1,087,191	33,357	1,637,365	15,026
14	Net Operating Income	1,078,962	470,213	257,773	10,475	335,624	4,878
15	Other Income Adjustments	17,252	9,378	4,284	77	3,476	36
16	Adjusted Net Operating Income	1,096,214	479,591	262,057	10,552	339,101	4,914
17	Return on Rate Base @ 6.12%	918,867	521,625	228,581	12,981	153,999	1,680
18	Income Deficiency (Sufficiency)	(177,347)	42,034	(33,475)	2,429	(185,101)	(3,233)
19	Revenue Deficiency (Sufficiency)	(237,305)	56,245	(44,793)	3,250	(247,680)	(4,327)
20	Additional Rev Requirement	40,158	6,557	7,912	38	25,415	238
21	Total Revenue Deficiency (Sufficiency)	(197,146)	62,802	(36,881)	3,287	(222,265)	(4,089)
22	Revenue Requirement/Total Cost of Service	5,922,834	2,801,094	1,308,082	47,119	1,750,724	15,815
23	Less: Revenue Credits	1,062,868	391,232	206,649	4,033	442,529	18,425
24	**Proposed Rate Design Revenue**	**4,859,965**	**2,409,862**	**1,101,433**	**43,086**	**1,308,195**	**(2,610)**
25	Production: Net Capacity Cost	1,105,401	488,807	234,527	1,876	377,060	3,131
26	Production: Capacity Related Cost Offset	339,952	114,259	64,254	1,416	158,716	1,307
27	Production: Non-Capacity Related Cost	1,274,470	450,843	257,082	4,897	571,030	(9,382)
28	Distribution: Demand Related Cost	1,891,197	1,168,664	500,609	33,415	186,272	2,238
29	Distribution: Customer Related Cost	248,945	187,288	44,962	1,482	15,118	95
30	Full Service MWH Sales	38,454,766	12,685,410	7,179,008	164,769	18,252,279	173,301
31	ROA MWH Sales	3,568,931	-	192,989	-	3,375,942	-
32	MWH Sales	42,023,697	12,685,410	7,371,997	164,769	21,628,220	173,301
33	Customers	1,918,109	1,680,798	227,572	5,560	4,166	14

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Rate Base**	8,528,549	8,528,549	2,344,649	1,392,645	3,737,295	7,719	178,573	25,942	212,235
2	**Revenue**									
3	Total Rate Revenue	2,347,060	2,347,060	704,496	433,818	1,138,314	1,542	28,157	10,099	39,799
4	Total Revenue Credits	391,232	391,232	122,765	83,884	206,649	236	1,349	2,448	4,033
5	Total Revenue	2,738,292	2,738,292	827,261	517,703	1,344,963	1,778	29,506	12,548	43,832
6	**Expenses:**									
7	Fuel and P&I Expense	780,398	780,398	253,284	174,288	427,572	455	2,301	5,225	7,981
8	Transmission Expense	300,835	300,835	94,589	61,931	156,520	113	434	1,518	2,064
9	Other O & M Expense	490,789	490,789	116,594	67,087	183,681	319	4,682	1,295	6,296
10	Depreciation & Amortization Expense	431,196	431,196	119,174	69,450	188,624	384	11,822	1,347	13,553
11	Other Taxes	198,874	198,874	58,405	36,215	94,619	138	1,134	721	1,994
12	Federal Income Taxes	65,987	65,987	22,793	13,381	36,174	45	1,124	301	1,470
13	Total Expenses	2,268,079	2,268,079	664,839	422,352	1,087,191	1,454	21,497	10,406	33,357
14	Net Operating Income	470,213	470,213	162,422	95,350	257,773	324	8,009	2,141	10,475
15	Other Income Adjustments	9,378	9,378	2,640	1,644	4,284	6	39	32	77
16	Adjusted Net Operating Income	479,591	479,591	165,062	96,995	262,057	330	8,048	2,174	10,552
17	Return on Rate Base @ 6.12%	521,625	521,625	143,404	85,177	228,581	472	10,922	1,587	12,981
18	Income Deficiency (Sufficiency)	42,034	42,034	(21,658)	(11,817)	(33,475)	142	2,874	(587)	2,429
19	Revenue Deficiency (Sufficiency)	56,245	56,245	(28,980)	(15,812)	(44,793)	190	3,845	(786)	3,250
20	Additional Rev Requirement	6,557	6,557	4,331	3,580	7,912	(7)	(53)	97	38
21	Total Revenue Deficiency (Sufficiency)	62,802	62,802	(24,649)	(12,232)	(36,881)	183	3,792	(688)	3,287
22	Revenue Requirement/Total Cost of Service	2,801,094	2,801,094	802,612	505,471	1,308,082	1,961	33,299	11,859	47,119
23	Less: Revenue Credits	391,232	391,232	122,765	83,884	206,649	236	1,349	2,448	4,033
24	**Proposed Rate Design Revenue**	**2,409,862**	**2,409,862**	**679,847**	**421,586**	**1,101,433**	**1,725**	**31,950**	**9,411**	**43,086**
25	Production: Net Capacity Cost	488,807	488,807	143,402	91,125	234,527	8	-	1,868	1,876
26	Production: Capacity Related Cost Offset	114,259	114,259	37,719	26,534	64,254	89	434	894	1,416
27	Production: Non-Capacity Related Cost	450,843	450,843	152,392	104,690	257,082	304	1,433	3,159	4,897
28	Distribution: Demand Related Cost	1,168,664	1,168,664	310,449	190,159	500,609	1,249	28,759	3,407	33,415
29	Distribution: Customer Related Cost	187,288	187,288	35,884	9,078	44,962	76	1,324	82	1,482
30	Full Service MWH Sales	12,685,410	12,685,410	4,199,402	2,979,606	7,179,008	10,776	54,640	99,352	164,769
31	ROA MWH Sales	-	-	18,702	174,288	192,989	-	-	-	-
32	MWH Sales	12,685,410	12,685,410	4,218,104	3,153,894	7,371,997	10,776	54,640	99,352	164,769
33	Customers	1,680,798	1,680,798	206,948	20,624	227,572	399	4,696	465	5,560

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Rate Base**	180,796	37,586	70,625	706,412	661,514	248,052	579,492	-	24,917	7,032	1,458	2,517,885
2	**Revenue**												
3	Total Rate Revenue	76,037	37,506	44,499	345,089	625,409	126,526	248,155	-	21,956	4,550	732	1,530,460
4	Total Revenue Credits	17,695	11,059	12,141	85,459	209,984	35,069	61,972	-	7,745	1,245	159	442,529
5	Total Revenue	93,732	48,565	56,640	430,548	835,393	161,595	310,127	-	29,702	5,795	891	1,972,989
6	**Expenses:**												
7	Fuel and P&I Expense	37,710	23,671	26,079	182,799	447,050	74,202	130,263	-	16,701	2,657	358	941,490
8	Transmission Expense	13,734	7,489	8,599	63,872	130,820	23,748	42,211	-	5,271	830	129	296,705
9	Other O & M Expense	6,651	1,859	2,405	28,609	33,273	7,353	22,919	-	1,242	232	57	104,600
10	Depreciation & Amortization Expense	10,673	3,321	4,645	42,192	58,309	13,970	32,314	-	2,208	435	79	168,147
11	Other Taxes	4,738	1,533	2,248	20,293	25,438	7,653	16,298	-	848	232	43	79,324
12	Federal Income Taxes	2,489	1,316	1,558	11,418	17,291	4,266	8,137	-	422	173	28	47,100
13	Total Expenses	75,995	39,188	45,534	349,184	712,181	131,193	252,143	-	26,693	4,560	693	1,637,365
14	Net Operating Income	17,737	9,377	11,105	81,364	123,212	30,402	57,985	-	3,009	1,235	197	335,624
15	Other Income Adjustments	206	67	91	888	1,185	288	696	-	45	9	2	3,476
16	Adjusted Net Operating Income	17,943	9,444	11,197	82,253	124,397	30,690	58,680	-	3,054	1,244	199	339,101
17	Return on Rate Base @ 6.12%	11,058	2,299	4,320	43,206	40,460	15,171	35,443	-	1,524	430	89	153,999
18	Income Deficiency (Sufficiency)	(6,885)	(7,145)	(6,877)	(39,047)	(83,937)	(15,519)	(23,237)	-	(1,530)	(814)	(110)	(185,101)
19	Revenue Deficiency (Sufficiency)	(9,213)	(9,561)	(9,202)	(52,248)	(112,314)	(20,765)	(31,093)	-	(2,047)	(1,089)	(147)	(247,680)
20	Additional Rev Requirement	1,106	660	749	5,224	11,670	1,976	3,510	-	444	67	8	25,415
21	Total Revenue Deficiency (Sufficiency)	(8,107)	(8,901)	(8,454)	(47,024)	(100,645)	(18,789)	(27,583)	-	(1,603)	(1,022)	(139)	(222,265)
22	Revenue Requirement/Total Cost of Service	85,625	39,664	48,186	383,525	734,748	142,806	282,544	-	28,099	4,773	751	1,750,724
23	Less: Revenue Credits	17,695	11,059	12,141	85,459	209,984	35,069	61,972	-	7,745	1,245	159	442,529
24	**Proposed Rate Design Revenue**	**67,930**	**28,606**	**36,046**	**298,066**	**524,764**	**107,737**	**220,572**	**-**	**20,353**	**3,528**	**592**	**1,308,195**
25	Production: Net Capacity Cost	19,012	9,276	10,770	85,973	157,518	28,536	58,938	-	6,015	900	120	377,060
26	Production: Capacity Related Cost Offset	6,019	3,791	4,189	29,795	77,748	11,726	21,696	-	3,178	506	68	158,716
27	Production: Non-Capacity Related Cost	23,385	14,437	16,140	112,972	268,262	46,085	77,385	-	10,443	1,667	255	571,030
28	Distribution: Demand Related Cost	16,585	970	4,498	64,306	19,674	20,462	58,567	-	653	421	136	186,272
29	Distribution: Customer Related Cost	2,929	131	450	5,021	1,562	927	3,987	-	65	34	13	15,118
30	Full Service MWH Sales	666,952	464,518	496,642	3,312,240	9,051,540	1,453,040	2,414,780	-	332,592	53,237	6,737	18,252,279
31	ROA MWH Sales	72,068	-	-	-	1,270,576	1,080,207	953,091	-	-	-	-	3,375,942
32	MWH Sales	739,020	464,518	496,642	3,312,240	10,322,116	2,533,246	3,367,871	-	332,592	53,237	6,737	21,628,220
33	Customers	1,420	23	80	1,413	37	98	1,077	-	5	7	5	4,166

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Net Plant**						
2	Production	2,251,061	937,372	466,181	5,344	834,899	7,265
3	Transmission	-	-	-	-	-	-
4	Distribution	9,996,812	5,975,938	2,635,847	189,798	1,178,140	17,088
5	General/Common/Intangible	730,148	439,768	169,043	5,379	115,007	952
6	Plant Purchased/Sold	0	0	0	0	0	0
7	Total Net Plant	12,978,021	7,353,078	3,271,072	200,520	2,128,046	25,304
8	**Working Capital**						
9	Total Current Assets	3,131,271	1,789,157	725,531	27,596	584,484	4,504
10	Total Current Liabilities	1,019,384	592,374	249,206	15,723	160,409	1,671
11	Total Working Capital	2,111,887	1,196,782	476,325	11,872	424,074	2,833
	Adjustments to Rate Base						
13	Additions to Rate Base	0	0	0	0	0	0
14	Deductions from Rate Base	66,473	21,311	10,102	158	34,235	666
15	Total Adjustments to Rate Base	(66,473)	(21,311)	(10,102)	(158)	(34,235)	(666)
16	**Total Rate Base**	**15,023,435**	**8,528,549**	**3,737,295**	**212,235**	**2,517,885**	**27,471**
17	**Production Expense**						
18	Fuel Expense	551,095	185,515	106,533	2,335	254,355	2,356
19	Purchased & Interchange Power Expense	1,614,933	594,883	321,039	5,646	687,134	6,231
20	Total Fuel and P&I Expense	2,166,028	780,398	427,572	7,981	941,490	8,587
21	Fossil O&M Exp	55,255	22,231	11,290	152	21,392	190
22	Nuclear O&M Exp	0	-	-	-	-	-
23	Hydro O&M Exp	13,209	5,239	2,684	38	5,201	47
23	Other Power Gen O&M Exp	64,631	26,913	13,385	153	23,971	209
24	Other Power Supply O&M Exp	5,268	2,194	1,091	13	1,954	17
25	Total Production O&M Expense	138,363	56,577	28,450	356	52,518	462
26	Total Production (Inc. Fuel and P&I) O&M Expense	2,304,390	836,975	456,022	8,337	994,008	9,049
27	**Transmission & Distribution Expense**						
28	Transmission Expense	758,515	300,835	156,520	2,064	296,705	2,391
29	Direct Assign Transmission	0	-	-	-	-	-
30	Distr Oper Exp	115,755	78,108	28,712	3,444	5,452	38
31	Distr Maint Exp	354,948	238,522	91,773	1,452	23,002	198
32	Total Transmission & Distribution O&M Expense	1,229,218	617,465	277,005	6,961	325,159	2,628
33	**Customer Related Expense**						
34	Customer Accounts Exp	59,788	43,397	9,354	245	6,787	6
35	Customer Service Exp	7,158	4,032	1,071	25	2,014	16
36	Other Customer Exp	16,687	13,846	2,664	85	92	0
37	Total Customer O&M Expense	83,634	61,275	13,089	354	8,893	23
38	**Admin & General Expense**	93,510	56,307	21,657	689	14,734	122
39	**Total O&M Expense**	**3,710,752**	**1,572,022**	**767,773**	**16,341**	**1,342,795**	**11,822**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Net Plant**									
2	Production	937,372	937,372	282,186	183,995	466,181	174	822	4,348	5,344
3	Transmission	-	-	-	-	-	-	-	-	-
4	Distribution	5,975,938	5,975,938	1,663,937	971,910	2,635,847	6,634	166,451	16,713	189,798
5	General/Common/Intangible	439,768	439,768	106,539	62,504	169,043	270	3,887	1,222	5,379
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0
7	Total Net Plant	7,353,078	7,353,078	2,052,662	1,218,410	3,271,072	7,078	171,160	22,283	200,520
8	**Working Capital**									
9	Total Current Assets	1,789,157	1,789,157	455,169	270,363	725,531	1,195	20,960	5,441	27,596
10	Total Current Liabilities	592,374	592,374	156,960	92,246	249,206	535	13,475	1,713	15,723
11	Total Working Capital	1,196,782	1,196,782	298,209	178,116	476,325	660	7,485	3,728	11,872
	Adjustments to Rate Base									
13	Additions to Rate Base	0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base	21,311	21,311	6,221	3,881	10,102	18	71	69	158
15	Total Adjustments to Rate Base	(21,311)	(21,311)	(6,221)	(3,881)	(10,102)	(18)	(71)	(69)	(158)
16	**Total Rate Base**	**8,528,549**	**8,528,549**	**2,344,649**	**1,392,645**	**3,737,295**	**7,719**	**178,573**	**25,942**	**212,235**
17	**Production Expense**									
18	Fuel Expense	185,515	185,515	62,486	44,048	106,533	147	747	1,441	2,335
19	Purchased & Interchange Power Expense	594,883	594,883	190,799	130,240	321,039	308	1,554	3,784	5,646
20	Total Fuel and P&I Expense	780,398	780,398	253,284	174,288	427,572	455	2,301	5,225	7,981
21	Fossil O&M Exp	22,231	22,231	6,795	4,495	11,290	6	31	114	152
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	5,239	5,239	1,612	1,073	2,684	2	9	28	38
23	Other Power Gen O&M Exp	26,913	26,913	8,102	5,283	13,385	5	24	125	153
24	Other Power Supply O&M Exp	2,194	2,194	660	431	1,091	0	2	10	13
25	Total Production O&M Expense	56,577	56,577	17,169	11,281	28,450	14	65	277	356
26	Total Production (Inc. Fuel and P&I) O&M Expense	836,975	836,975	270,453	185,569	456,022	468	2,366	5,502	8,337
27	**Transmission & Distribution Expense**									
28	Transmission Expense	300,835	300,835	94,589	61,931	156,520	113	434	1,518	2,064
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	78,108	78,108	17,893	10,820	28,712	91	3,157	197	3,444
31	Distr Maint Exp	238,522	238,522	57,693	34,079	91,773	157	698	597	1,452
32	Total Transmission & Distribution O&M Expense	617,465	617,465	170,175	106,830	277,005	361	4,288	2,312	6,961
33	**Customer Related Expense**									
34	Customer Accounts Exp	43,397	43,397	7,101	2,253	9,354	15	180	50	245
35	Customer Service Exp	4,032	4,032	743	328	1,071	2	13	10	25
36	Other Customer Exp	13,846	13,846	2,346	318	2,664	6	71	7	85
37	Total Customer O&M Expense	61,275	61,275	10,189	2,899	13,089	22	265	67	354
38	**Admin & General Expense**	56,307	56,307	13,649	8,008	21,657	35	498	157	689
39	**Total O&M Expense**	**1,572,022**	**1,572,022**	**464,466**	**303,307**	**767,773**	**886**	**7,417**	**8,037**	**16,341**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate - GPTU Vlt 1	(d) Rate - GPTU Vlt 2	(e) Rate - GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Net Plant**												
2	Production	38,728	20,769	23,594	179,467	367,718	63,274	125,013	-	13,914	2,141	282	834,899
3	Transmission	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	112,859	6,742	34,195	395,406	116,075	149,298	354,556	-	4,414	3,668	928	1,178,140
5	General/Common/Intangible	6,931	2,200	2,811	30,141	39,073	8,452	23,611	-	1,464	266	57	115,007
6	Plant Purchased/Sold	0	0	0	0	0	0	0	-	0	0	0	0
7	Total Net Plant	158,518	29,711	60,600	605,014	522,865	221,023	503,180	-	19,792	6,076	1,267	2,128,046
8	**Working Capital**												
9	Total Current Assets	34,007	11,748	15,250	146,879	207,527	46,042	113,553	-	7,709	1,483	285	584,484
10	Total Current Liabilities	11,444	2,482	4,370	44,721	43,589	15,088	36,552	-	1,639	432	92	160,409
11	Total Working Capital	22,564	9,266	10,880	102,157	163,939	30,954	77,001	-	6,070	1,051	193	424,074
	Adjustments to Rate Base												
13	Additions to Rate Base	0	0	0	0	0	0	0	-	0	0	0	0
14	Deductions from Rate Base	286	1,391	856	760	25,290	3,925	689	-	944	94	2	34,235
15	Total Adjustments to Rate Base	(286)	(1,391)	(856)	(760)	(25,290)	(3,925)	(689)	-	(944)	(94)	(2)	(34,235)
16	**Total Rate Base**	**180,796**	**37,586**	**70,625**	**706,412**	**661,514**	**248,052**	**579,492**	**-**	**24,917**	**7,032**	**1,458**	**2,517,885**
17	**Production Expense**												
18	Fuel Expense	9,642	6,418	6,997	47,593	123,740	20,307	34,212	-	4,604	740	101	254,355
19	Purchased & Interchange Power Expense	28,068	17,253	19,081	135,206	323,310	53,894	96,051	-	12,096	1,917	258	687,134
20	Total Fuel and P&I Expense	37,710	23,671	26,079	182,799	447,050	74,202	130,263	-	16,701	2,657	358	941,490
21	Fossil O&M Exp	951	535	601	4,464	9,655	1,622	3,135	-	364	57	7	21,392
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	227	130	146	1,073	2,369	395	756	-	89	14	2	5,201
23	Other Power Gen O&M Exp	1,112	596	677	5,153	10,558	1,817	3,589	-	399	61	8	23,971
24	Other Power Supply O&M Exp	91	49	55	420	861	148	293	-	33	5	1	1,954
25	Total Production O&M Expense	2,381	1,310	1,480	11,110	23,443	3,982	7,773	-	885	137	18	52,518
26	Total Production (Inc. Fuel and P&I) O&M Expense	40,091	24,981	27,559	193,909	470,493	78,183	138,036	-	17,586	2,794	376	994,008
27	**Transmission & Distribution Expense**												
28	Transmission Expense	13,734	7,489	8,599	63,872	130,820	23,748	42,211	-	5,271	830	129	296,705
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	489	6	21	2,377	181	172	2,193	-	6	3	5	5,452
31	Distr Maint Exp	2,453	51	300	9,410	877	1,322	8,502	-	33	32	22	23,002
32	Total Transmission & Distribution O&M Expense	16,676	7,546	8,920	75,659	131,878	25,242	52,906	-	5,310	866	157	325,159
33	**Customer Related Expense**												
34	Customer Accounts Exp	347	166	196	1,513	2,798	556	1,090	-	99	20	3	6,787
35	Customer Service Exp	71	43	46	310	958	235	314	-	31	5	1	2,014
36	Other Customer Exp	23	1	2	29	10	4	22	-	0	0	0	92
37	Total Customer O&M Expense	441	210	244	1,851	3,767	795	1,426	-	130	25	4	8,893
38	**Admin & General Expense**	888	282	360	3,862	5,006	1,083	3,025	-	188	34	7	14,734
39	**Total O&M Expense**	**58,095**	**33,019**	**37,083**	**275,281**	**611,144**	**105,303**	**195,394**	**-**	**23,214**	**3,719**	**544**	**1,342,795**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
	Input Allocation Schedules						
1	Energy @ Generation	100.000	33.906	19.188	0.440	46.025	0.441
2	Energy On-Peak @ Generation	100.000	32.760	20.818	0.340	45.730	0.351
3	Energy Off-Peak @ Generation	100.000	34.750	17.300	0.540	46.880	0.530
4	Energy On-Peak @ Generation Summer	100.000	34.135	21.405	0.284	43.813	0.363
5	Energy Off-Peak @ Generation Summer	100.000	35.421	17.712	0.487	45.800	0.579
6	Energy On-Peak @ Generation Non-Summer	100.000	31.974	20.483	0.372	46.826	0.344
7	Energy Off-Peak @ Generation Non-Summer	100.000	34.385	17.075	0.569	47.467	0.504
8	Energy Critical On-Peak @ Gen	100.000	36.621	21.818	0.218	41.083	0.259
9	Energy Summer Mid-Peak @ Gen	100.000	33.229	21.254	0.308	44.809	0.401
10	12CP Dmd @ Generation	100.000	39.661	20.635	0.272	39.117	0.315
11	4CP Dmd @ Generation	100.000	44.220	21.216	0.170	34.111	0.283
12	Class Peak @ Voltage 1	100.000	41.935	19.878	0.312	37.315	0.561
13	Production Revenue	100.000	37.294	20.190	0.336	42.222	(0.042)
14	Distribution Revenue	100.000	61.655	26.328	1.586	10.271	0.160
15	Total Rate Revenue	100.000	45.705	22.309	0.768	31.190	0.028
16	Billed Sales	100.000	30.186	17.542	0.392	51.467	0.412
17	Number Of Customers	100.000	87.628	11.864	0.290	0.217	0.001
18	Weighted Customer	100.000	60.166	28.619	0.054	11.124	0.038
		-					
	*Calculated Allocation Schedules						
19	4CP 75/0/25	100.000	41.641	20.709	0.237	37.089	0.323
20	Class Peak @ Voltage 2	100.000	50.207	23.799	0.373	24.949	0.672
21	Class Peak Voltage 1 Only	100.000	-	-	-	98.503	1.497
22	Class Peak Voltage 2 Only	100.000	-	-	-	95.387	4.613
23	Class Peak @ Voltage 1 excluding Voltage 2	100.000	44.342	21.019	0.329	33.982	0.329
24	Class Peak @ Voltage 3	100.000	53.875	25.538	0.400	20.109	0.077
25	Class Peak @ Voltage 4	100.000	67.502	31.997	0.501	-	-
26	Class Peak for Streetlighting	100.000	-	-	100.000	-	-
27	Class Peak @ Single Phase	100.000	67.502	31.997	0.501	-	-
28	Billed Sales - Primary	100.000	45.911	26.681	0.596	26.744	0.067
29	Customers - Residential	100.000	100.000	-	-	-	-
30	Customers - Commercial Secondary	100.000	-	100.000	-	-	-
31	Customers - Non-Primary	100.000	88.057	11.922	0.021	-	-
32	Customers - Non-Lighting	100.000	87.883	11.899	-	0.218	0.001
33	Customers - Commercial & Primary	100.000	-	98.196	-	1.798	0.006
34	Customer Count (CCC)	100.000	93.559	6.441	-	-	-
35	Customer Count (BCC)	100.000	-	91.990	4.572	3.426	0.012
36	PIS - HVD (Voltage 1)	100.000	50.168	23.781	0.373	25.071	0.607
37	PIS - HVD (Voltage 2)	100.000	50.117	23.756	0.372	25.218	0.537
38	PIS - HVD (Voltage 1) Substations	100.000	50.207	23.799	0.373	24.949	0.672
39	PIS - HVD (Voltage 2) Substations	100.000	41.526	19.684	0.309	37.365	1.117
40	PIS - OH LVD System	100.000	63.654	30.173	0.473	5.678	0.022
41	PIS - LVD Distribution	100.000	63.001	26.146	2.447	8.323	0.082
42	PIS- OH (LVD & HVD) Lines & Services	100.000	66.214	25.689	0.389	7.625	0.083
43	PIS- UG LVD Distribution	100.000	63.298	30.005	0.470	6.184	0.043
44	PIS- Total Distribution	100.000	61.233	25.819	2.162	10.638	0.148

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
	Input Allocation Schedules									
1	Energy @ Generation	33.906	33.906	11.224	7.964	19.188	0.029	0.146	0.266	0.440
2	Energy On-Peak @ Generation	32.760	32.760	12.407	8.412	20.818	0.015	0.078	0.248	0.340
3	Energy Off-Peak @ Generation	34.750	34.750	9.882	7.418	17.300	0.043	0.215	0.282	0.540
4	Energy On-Peak @ Generation Summer	34.135	34.135	12.788	8.616	21.405	0.007	0.048	0.229	0.284
5	Energy Off-Peak @ Generation Summer	35.421	35.421	10.126	7.587	17.712	0.036	0.187	0.264	0.487
6	Energy On-Peak @ Generation Non-Summer	31.974	31.974	12.189	8.295	20.483	0.019	0.095	0.258	0.372
7	Energy Off-Peak @ Generation Non-Summer	34.385	34.385	9.749	7.326	17.075	0.047	0.230	0.291	0.569
8	Energy Critical On-Peak @ Gen	36.621	36.621	13.089	8.729	21.818	0.001	0.003	0.214	0.218
9	Energy Summer Mid-Peak @ Gen	33.229	33.229	12.679	8.575	21.254	0.009	0.065	0.234	0.308
10	12CP Dmd @ Generation	39.661	39.661	12.470	8.165	20.635	0.015	0.057	0.200	0.272
11	4CP Dmd @ Generation	44.220	44.220	12.973	8.244	21.216	0.001	-	0.169	0.170
12	Class Peak @ Voltage 1	41.935	41.935	12.242	7.636	19.878	0.035	0.141	0.136	0.312
13	Production Revenue	37.294	37.294	12.000	8.190	20.190	0.018	0.089	0.229	0.336
14	Distribution Revenue	61.655	61.655	17.136	9.192	26.328	0.053	1.379	0.154	1.586
15	Total Rate Revenue	45.705	45.705	13.773	8.536	22.309	0.030	0.535	0.203	0.768
16	Billed Sales	30.186	30.186	10.037	7.505	17.542	0.026	0.130	0.236	0.392
17	Number Of Customers	87.628	87.628	10.789	1.075	11.864	0.021	0.245	0.024	0.290
18	Weighted Customer	60.166	60.166	23.310	5.309	28.619	0.054	-	-	0.054
	*Calculated Allocation Schedules									
19	4CP 75/0/25	41.641	41.641	12.536	8.174	20.709	0.008	0.037	0.193	0.237
20	Class Peak @ Voltage 2	50.207	50.207	14.657	9.142	23.799	0.042	0.168	0.163	0.373
21	Class Peak Voltage 1 Only	-	-	-	-	-	-	-	-	-
22	Class Peak Voltage 2 Only	-	-	-	-	-	-	-	-	-
23	Class Peak @ Voltage 1 excluding Voltage 2	44.342	44.342	12.944	8.074	21.019	0.037	0.149	0.144	0.329
24	Class Peak @ Voltage 3	53.875	53.875	15.728	9.810	25.538	0.045	0.181	0.175	0.400
25	Class Peak @ Voltage 4	67.502	67.502	19.705	12.291	31.997	0.056	0.226	0.219	0.501
26	Class Peak for Streetlighting	-	-	-	-	-	19.934	80.066	-	100.000
27	Class Peak @ Single Phase	67.502	67.502	19.705	12.291	31.997	0.056	0.226	0.219	0.501
28	Billed Sales - Primary	45.911	45.911	15.266	11.415	26.681	0.039	0.198	0.360	0.596
29	Customers - Residential	100.000	100.000	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	90.937	9.063	100.000	-	-	-	-
31	Customers - Non-Primary	88.057	88.057	10.842	1.080	11.922	0.021	-	-	0.021
32	Customers - Non-Lighting	87.883	87.883	10.821	1.078	11.899	-	-	-	-
33	Customers - Commercial & Primary	-	-	89.297	8.899	98.196	-	-	-	-
34	Customer Count (CCC)	93.559	93.559	6.388	0.054	6.441	-	-	-	-
35	Customer Count (BCC)	-	-	75.820	16.170	91.990	0.328	3.862	0.382	4.572
36	PIS - HVD (Voltage 1)	50.168	50.168	14.645	9.135	23.781	0.042	0.168	0.163	0.373
37	PIS - HVD (Voltage 2)	50.117	50.117	14.630	9.126	23.756	0.042	0.168	0.162	0.372
38	PIS - HVD (Voltage 1) Substations	50.207	50.207	14.657	9.142	23.799	0.042	0.168	0.163	0.373
39	PIS - HVD (Voltage 2) Substations	41.526	41.526	12.122	7.562	19.684	0.035	0.139	0.135	0.309
40	PIS - OH LVD System	63.654	63.654	18.582	11.591	30.173	0.053	0.214	0.206	0.473
41	PIS - LVD Distribution	63.001	63.001	16.653	9.493	26.146	0.073	2.212	0.162	2.447
42	PIS- OH (LVD & HVD) Lines & Services	66.214	66.214	16.075	9.615	25.689	0.044	0.176	0.170	0.389
43	PIS- UG LVD Distribution	63.298	63.298	18.478	11.526	30.005	0.053	0.212	0.205	0.470
44	PIS- Total Distribution	61.233	61.233	16.375	9.443	25.819	0.069	1.931	0.162	2.162

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
	Input Allocation Schedules												
1	Energy @ Generation	1.722	1.173	1.269	8.558	22.592	3.499	6.219	-	0.840	0.136	0.017	46.025
2	Energy On-Peak @ Generation	2.000	1.160	1.329	9.499	20.876	3.657	6.202	-	0.851	0.130	0.025	45.730
3	Energy Off-Peak @ Generation	1.416	1.174	1.194	7.494	24.683	3.736	6.213	-	0.819	0.141	0.009	46.880
4	Energy On-Peak @ Generation Summer	2.009	1.118	1.278	9.422	19.297	3.496	6.271	-	0.780	0.118	0.023	43.813
5	Energy Off-Peak @ Generation Summer	1.437	1.147	1.185	7.606	23.479	3.626	6.397	-	0.781	0.132	0.009	45.800
6	Energy On-Peak @ Generation Non-Summer	1.994	1.184	1.358	9.542	21.779	3.749	6.163	-	0.892	0.137	0.027	46.826
7	Energy Off-Peak @ Generation Non-Summer	1.405	1.189	1.199	7.432	25.338	3.796	6.113	-	0.840	0.146	0.009	47.467
8	Energy Critical On-Peak @ Gen	1.888	1.020	1.178	8.935	17.945	3.260	6.013	-	0.733	0.098	0.013	41.083
9	Energy Summer Mid-Peak @ Gen	2.053	1.154	1.315	9.600	19.790	3.582	6.365	-	0.797	0.125	0.027	44.809
10	12CP Dmd @ Generation	1.811	0.987	1.134	8.421	17.247	3.131	5.565	-	0.695	0.109	0.017	39.117
11	4CP Dmd @ Generation	1.720	0.839	0.974	7.778	14.250	2.582	5.332	-	0.544	0.081	0.011	34.111
12	Class Peak @ Voltage 1	1.911	0.829	0.894	7.253	15.075	4.100	6.575	-	0.563	0.099	0.017	37.315
13	Production Revenue	1.755	1.131	1.235	8.407	19.664	3.394	5.839	-	0.676	0.108	0.014	42.222
14	Distribution Revenue	1.063	0.075	0.271	4.104	0.268	1.010	3.356	-	0.043	0.064	0.016	10.271
15	Total Rate Revenue	1.516	0.767	0.902	6.921	12.967	2.571	4.982	-	0.457	0.093	0.015	31.190
16	Billed Sales	1.759	1.105	1.182	7.882	24.563	6.028	8.014	-	0.791	0.127	0.016	51.467
17	Number Of Customers	0.074	0.001	0.004	0.074	0.002	0.005	0.056	-	0.000	0.000	0.000	0.217
18	Weighted Customer	3.005	0.071	0.361	4.140	0.128	0.303	3.065	-	0.019	0.021	0.011	11.124
		-	-	-	-	-	-	-	-	-	-	-	-
	*Calculated Allocation Schedules	-	-	-	-	-	-	-	-	-	-	-	-
19	4CP 75/0/25	1.720	0.923	1.048	7.973	16.335	2.811	5.554	-	0.618	0.095	0.013	37.089
20	Class Peak @ Voltage 2	2.277	-	1.070	8.684	-	4.908	7.871	-	-	0.118	0.020	24.949
21	Class Peak Voltage 1 Only	0.053	4.956	-	-	90.128	-	-	-	3.366	-	-	98.503
22	Class Peak Voltage 2 Only	1.574	-	16.464	-	-	75.532	-	-	-	1.817	-	95.387
23	Class Peak @ Voltage 1 excluding Voltage 2	1.930	0.876	-	7.670	15.941	-	6.952	-	0.595	-	0.018	33.982
24	Class Peak @ Voltage 3	2.323	-	-	9.318	-	-	8.447	-	-	-	0.022	20.109
25	Class Peak @ Voltage 4	-	-	-	-	-	-	-	-	-	-	-	-
26	Class Peak for Streetlighting	-	-	-	-	-	-	-	-	-	-	-	-
27	Class Peak @ Single Phase	-	-	-	-	-	-	-	-	-	-	-	-
28	Billed Sales - Primary	2.543	-	-	11.988	-	-	12.189	-	-	-	0.024	26.744
29	Customers - Residential	-	-	-	-	-	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	-	-	-	-	-	-	-	-	-	-
31	Customers - Non-Primary	-	-	-	-	-	-	-	-	-	-	-	-
32	Customers - Non-Lighting	0.074	0.001	0.004	0.074	0.002	0.005	0.056	-	0.000	0.000	0.000	0.218
33	Customers - Commercial & Primary	0.613	0.010	0.035	0.610	0.016	0.042	0.465	-	0.002	0.003	0.002	1.798
34	Customer Count (CCC)	-	-	-	-	-	-	-	-	-	-	-	-
35	Customer Count (BCC)	1.168	0.019	0.066	1.162	0.031	0.080	0.886	-	0.004	0.006	0.004	3.426
36	PIS - HVD (Voltage 1)	2.263	0.042	0.949	8.677	0.769	4.352	7.865	-	0.029	0.105	0.020	25.071
37	PIS - HVD (Voltage 2)	1.945	-	1.687	7.157	-	7.739	6.487	-	-	0.186	0.017	25.218
38	PIS - HVD (Voltage 1) Substations	2.277	-	1.070	8.684	-	4.908	7.871	-	-	0.118	0.020	24.949
39	PIS - HVD (Voltage 2) Substations	2.151	-	3.774	7.182	-	17.314	6.510	-	-	0.417	0.017	37.365
40	PIS - OH LVD System	0.656	-	-	2.631	-	-	2.385	-	-	-	0.006	5.678
41	PIS - LVD Distribution	0.889	0.065	0.116	2.990	1.098	0.441	2.663	-	0.042	0.012	0.007	8.323
42	PIS- OH (LVD & HVD) Lines & Services	0.774	0.014	0.129	3.054	0.262	0.592	2.768	-	0.010	0.014	0.007	7.625
43	PIS- UG LVD Distribution	0.556	0.067	0.008	2.223	1.226	0.037	2.015	-	0.046	0.001	0.005	6.184
44	PIS- Total Distribution	1.049	0.058	0.297	3.635	0.984	1.284	3.254	-	0.038	0.032	0.009	10.638

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	*Calculated Allocation Schedules						
2	PIS- Distribution Services	100.000	94.121	5.879	-	-	-
3	PIS- Streetlighting Equipment	100.000	-	-	100.000	-	-
4	PIS- Line Equipment	100.000	66.184	31.372	0.492	1.944	0.007
5	PIS- Meters	100.000	60.166	28.619	0.054	11.124	0.038
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000
7	Total PIS	100.000	57.142	24.573	1.661	16.442	0.183
8	Distribution Depreciation	100.000	64.795	24.617	2.708	7.788	0.092
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	100.000	34.944	16.564	0.260	47.656	0.576
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	100.000	50.502	23.939	0.375	24.694	0.491
11	PIS- LVD OH Lines & Services	100.000	68.843	26.036	0.392	4.711	0.018
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	100.000	-	-	-	98.503	1.497
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	100.000	52.165	24.727	0.388	22.394	0.327
14	CWIP	100.000	54.360	24.832	0.448	20.151	0.209
15	Rate Base- Total	100.000	56.768	24.876	1.413	16.760	0.183
16	Dist Op Expense (LVD) excl Sup & Eng	100.000	67.911	24.847	3.035	4.185	0.022
17	Dist Maint Expense (LVD) excl Sup & Eng	100.000	68.695	26.092	0.413	4.781	0.018
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.047	21.353	0.335	32.739	0.525
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.522	21.578	0.338	32.038	0.523
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.626	23.524	0.369	25.955	0.526
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.354	23.395	0.367	26.347	0.537
22	Total HVD Distribution O&M Expense	100.000	48.212	22.853	0.358	28.044	0.532
23	Total Distribution O&M Expense (excl. HVD)	100.000	68.541	25.773	1.077	4.590	0.018
24	Total Customer Accounts Expense (excl. Supv)	100.000	72.584	15.645	0.410	11.351	0.010
25	Total Customer Accounts & Service Expense	100.000	70.846	15.571	0.403	13.147	0.033
26	Pre Tax NOI	100.000	43.580	23.891	0.971	31.106	0.452
27	Depreciation & Amortization Expense	100.000	53.690	23.486	1.687	20.937	0.199
28	Non PSCR O&M Expense	100.000	62.425	23.363	0.801	13.304	0.107
29	Distribution Depreciation Expense	100.000	61.447	25.637	2.973	9.819	0.123
30	Gen/Comm/Int Depreciation Expense	100.000	60.215	23.161	0.737	15.757	0.130
31	Production Labor	100.000	41.641	20.709	0.237	37.089	0.323
32	Total Labor	100.000	60.215	23.161	0.737	15.757	0.130
33	50% O&M, 50% Net Plant	100.000	53.480	24.201	1.299	20.797	0.222
34	50/50 PIS & Labor	100.000	58.678	23.867	1.199	16.099	0.156

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	*Calculated Allocation Schedules									
2	PIS- Distribution Services	94.121	94.121	5.347	0.533	5.879	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	1.423	98.577	-	100.000
4	PIS- Line Equipment	66.184	66.184	19.321	12.052	31.372	0.055	0.222	0.214	0.492
5	PIS- Meters	60.166	60.166	23.310	5.309	28.619	0.054	-	-	0.054
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Total PIS	57.142	57.142	15.455	9.117	24.573	0.054	1.439	0.169	1.661
8	Distribution Depreciation	64.795	64.795	15.775	8.842	24.617	0.074	2.484	0.150	2.708
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	34.944	34.944	10.201	6.363	16.564	0.029	0.117	0.113	0.260
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	50.502	50.502	14.743	9.196	23.939	0.042	0.169	0.164	0.375
11	PIS- LVD OH Lines & Services	68.843	68.843	16.328	9.708	26.036	0.044	0.177	0.171	0.392
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	-	-	-	-	-	-	-	-	-
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	52.165	52.165	15.228	9.499	24.727	0.044	0.175	0.169	0.388
14	CWIP	54.360	54.360	15.302	9.530	24.832	0.034	0.226	0.188	0.448
15	Rate Base- Total	56.768	56.768	15.607	9.270	24.876	0.051	1.189	0.173	1.413
16	Dist Op Expense (LVD) excl Sup & Eng	67.911	67.911	15.488	9.359	24.847	0.080	2.785	0.170	3.035
17	Dist Maint Expense (LVD) excl Sup & Eng	68.695	68.695	16.426	9.666	26.092	0.045	0.199	0.169	0.413
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	45.047	45.047	13.151	8.203	21.353	0.038	0.151	0.146	0.335
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	45.522	45.522	13.289	8.289	21.578	0.038	0.153	0.147	0.338
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	49.626	49.626	14.487	9.037	23.524	0.041	0.166	0.161	0.369
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	49.354	49.354	14.408	8.987	23.395	0.041	0.166	0.160	0.367
22	Total HVD Distribution O&M Expense	48.212	48.212	14.074	8.779	22.853	0.040	0.162	0.156	0.358
23	Total Distribution O&M Expense (excl. HVD)	68.541	68.541	16.185	9.589	25.773	0.053	0.854	0.170	1.077
24	Total Customer Accounts Expense (excl. Supv)	72.584	72.584	11.876	3.769	15.645	0.024	0.301	0.084	0.410
25	Total Customer Accounts & Service Expense	70.846	70.846	11.716	3.855	15.571	0.024	0.289	0.090	0.403
26	Pre Tax NOI	43.580	43.580	15.054	8.837	23.891	0.030	0.742	0.198	0.971
27	Depreciation & Amortization Expense	53.690	53.690	14.839	8.648	23.486	0.048	1.472	0.168	1.687
28	Non PSCR O&M Expense	62.425	62.425	14.830	8.533	23.363	0.041	0.596	0.165	0.801
29	Distribution Depreciation Expense	61.447	61.447	16.618	9.019	25.637	0.080	2.745	0.148	2.973
30	Gen/Comm/Int Depreciation Expense	60.215	60.215	14.597	8.564	23.161	0.037	0.533	0.167	0.737
31	Production Labor	41.641	41.641	12.536	8.174	20.709	0.008	0.037	0.193	0.237
32	Total Labor	60.215	60.215	14.597	8.564	23.161	0.037	0.533	0.167	0.737
33	50% O&M, 50% Net Plant	53.480	53.480	15.083	9.118	24.201	0.048	1.070	0.182	1.299
34	50/50 PIS & Labor	58.678	58.678	15.026	8.841	23.867	0.045	0.986	0.168	1.199

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	*Calculated Allocation Schedules												
2	PIS- Distribution Services	-	-	-	-	-	-	-	-	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	-	-	-	-	-	-	-
4	PIS- Line Equipment	0.225	-	-	0.901	-	-	0.817	-	-	-	0.002	1.944
5	PIS- Meters	3.005	0.071	0.361	4.140	0.128	0.303	3.065	-	0.019	0.021	0.011	11.124
6	PIS - General	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-	0.000	0.000	0.000	0.000
7	Total PIS	1.179	0.253	0.458	4.561	4.456	1.588	3.724	-	0.169	0.045	0.009	16.442
8	Distribution Depreciation	0.842	0.035	0.181	2.838	0.561	0.751	2.531	-	0.022	0.019	0.007	7.788
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	1.527	1.741	-	6.044	31.669	-	5.479	-	1.183	-	0.014	47.656
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	2.278	-	1.008	8.735	-	4.623	7.918	-	-	0.111	0.020	24.694
11	PIS- LVD OH Lines & Services	0.544	-	-	2.183	-	-	1.979	-	-	-	0.005	4.711
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	0.053	4.956	-	-	90.128	-	-	-	3.366	-	-	98.503
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	2.301	-	0.504	9.023	-	2.311	8.178	-	-	0.056	0.021	22.394
14	CWIP	1.195	0.387	0.529	5.148	6.869	1.669	4.033	-	0.259	0.051	0.010	20.151
15	Rate Base- Total	1.203	0.250	0.470	4.702	4.403	1.651	3.857	-	0.166	0.047	0.010	16.760
16	Dist Op Expense (LVD) excl Sup & Eng	0.382	0.001	(0.005)	1.910	0.081	0.043	1.765	-	0.002	0.000	0.004	4.185
17	Dist Maint Expense (LVD) excl Sup & Eng	0.573	0.001	0.004	2.203	0.002	0.004	1.989	-	0.000	0.000	0.005	4.781
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	1.998	0.666	0.463	7.792	12.112	2.124	7.063	-	0.452	0.051	0.018	32.739
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	2.020	0.615	0.485	7.874	11.193	2.224	7.137	-	0.418	0.054	0.018	32.038
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	2.265	-	1.282	8.584	-	5.882	7.780	-	-	0.142	0.020	25.955
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	2.261	-	1.367	8.537	-	6.273	7.738	-	-	0.151	0.020	26.347
22	Total HVD Distribution O&M Expense	2.189	0.186	1.097	8.339	3.375	5.033	7.559	-	0.126	0.121	0.019	28.044
23	Total Distribution O&M Expense (excl. HVD)	0.521	0.001	0.000	2.119	0.016	0.006	1.923	-	0.001	0.000	0.005	4.590
24	Total Customer Accounts Expense (excl. Supv)	0.580	0.277	0.327	2.530	4.680	0.930	1.823	-	0.165	0.034	0.005	11.351
25	Total Customer Accounts & Service Expense	0.624	0.312	0.361	2.722	5.611	1.182	2.097	-	0.194	0.037	0.006	13.147
26	Pre Tax NOI	1.644	0.869	1.029	7.541	11.419	2.818	5.374	-	0.279	0.115	0.018	31.106
27	Depreciation & Amortization Expense	1.329	0.413	0.578	5.254	7.260	1.740	4.024	-	0.275	0.054	0.010	20.937
28	Non PSCR O&M Expense	0.846	0.236	0.306	3.639	4.232	0.935	2.915	-	0.158	0.030	0.007	13.304
29	Distribution Depreciation Expense	1.112	0.052	0.263	3.434	0.811	1.048	3.031	-	0.032	0.027	0.008	9.819
30	Gen/Comm/Int Depreciation Expense	0.950	0.301	0.385	4.130	5.353	1.158	3.235	-	0.201	0.036	0.008	15.757
31	Production Labor	1.720	0.923	1.048	7.973	16.335	2.811	5.554	-	0.618	0.095	0.013	37.089
32	Total Labor	0.950	0.301	0.385	4.130	5.353	1.158	3.235	-	0.201	0.036	0.008	15.757
33	50% O&M, 50% Net Plant	1.298	0.376	0.585	5.275	6.795	1.955	4.186	-	0.258	0.059	0.011	20.797
34	50/50 PIS & Labor	1.064	0.277	0.421	4.345	4.905	1.373	3.479	-	0.185	0.041	0.009	16.099

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Rate Base**	15,023,435	8,528,549	3,737,295	212,235	2,517,886	27,471
2	**Revenue**						
3	Total Rate Revenue	5,057,111	2,347,060	1,138,314	39,799	1,530,460	1,478
4	Total Revenue Credits	1,062,868	391,232	206,649	4,033	442,529	18,425
5	Total Revenue	6,119,980	2,738,292	1,344,963	43,832	1,972,989	19,904
6	**Expenses:**						
7	Fuel and P&I Expense	2,166,028	780,398	427,572	7,981	941,490	8,587
8	Transmission Expense	758,515	300,835	156,520	2,064	296,705	2,391
9	Other O & M Expense	786,210	490,789	183,681	6,296	104,600	844
10	Depreciation & Amortization Expense	803,119	431,196	188,624	13,553	168,147	1,599
11	Other Taxes	375,732	198,874	94,619	1,994	79,324	921
12	Federal Income Taxes	151,415	65,987	36,174	1,470	47,100	684
13	Total Expenses	5,041,018	2,268,079	1,087,191	33,357	1,637,365	15,026
14	Net Operating Income	1,078,962	470,213	257,773	10,475	335,624	4,878
15	Other Income Adjustments	17,252	9,378	4,284	77	3,476	36
16	Adjusted Net Operating Income	1,096,214	479,591	262,057	10,552	339,100	4,914
17	Return on Rate Base @ 6.12%	918,867	521,625	228,581	12,981	154,000	1,680
18	Income Deficiency (Sufficiency)	(177,347)	42,034	(33,475)	2,429	(185,101)	(3,233)
19	Revenue Deficiency (Sufficiency)	(237,305)	56,245	(44,793)	3,250	(247,680)	(4,327)
20	Additional Rev Requirement	40,158	6,557	7,912	38	25,415	238
21	Total Revenue Deficiency (Sufficiency)	(197,146)	62,802	(36,881)	3,287	(222,265)	(4,089)
22	Revenue Requirement/Total Cost of Service	5,922,834	2,801,094	1,308,082	47,119	1,750,724	15,815
23	Less: Revenue Credits	1,062,868	391,232	206,649	4,033	442,529	18,425
24	**Proposed Rate Design Revenue**	**4,859,965**	**2,409,862**	**1,101,433**	**43,086**	**1,308,195**	**(2,610)**
25	Production: Net Capacity Cost	1,105,401	488,807	234,527	1,876	377,060	3,131
26	Production: Capacity Related Cost Offset	339,952	114,259	64,254	1,416	158,716	1,307
27	Production: Non-Capacity Related Cost	1,274,471	450,843	257,082	4,897	571,031	(9,382)
28	Distribution: Demand Related Cost	1,891,196	1,168,664	500,609	33,415	186,270	2,238
29	Distribution: Customer Related Cost	248,945	187,288	44,962	1,482	15,118	95
30	Full Service MWH Sales	38,454,766	12,685,410	7,179,008	164,769	18,252,279	173,301
31	ROA MWH Sales	3,568,931	-	192,989	-	3,375,942	-
32	MWH Sales	42,023,697	12,685,410	7,371,997	164,769	21,628,220	173,301
33	Customers	1,918,109	1,680,798	227,572	5,560	4,166	14

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Rate Base**	8,528,549	8,528,549	2,344,649	1,392,645	3,737,295	7,719	178,573	25,942	212,235
2	**Revenue**									
3	Total Rate Revenue	2,347,060	2,347,060	704,496	433,818	1,138,314	1,542	28,157	10,099	39,799
4	Total Revenue Credits	391,232	391,232	122,765	83,884	206,649	236	1,349	2,448	4,033
5	Total Revenue	2,738,292	2,738,292	827,261	517,703	1,344,963	1,778	29,506	12,548	43,832
6	**Expenses:**									
7	Fuel and P&I Expense	780,398	780,398	253,284	174,288	427,572	455	2,301	5,225	7,981
8	Transmission Expense	300,835	300,835	94,589	61,931	156,520	113	434	1,518	2,064
9	Other O & M Expense	490,789	490,789	116,594	67,087	183,681	319	4,682	1,295	6,296
10	Depreciation & Amortization Expense	431,196	431,196	119,174	69,450	188,624	384	11,822	1,347	13,553
11	Other Taxes	198,874	198,874	58,405	36,215	94,619	138	1,134	721	1,994
12	Federal Income Taxes	65,987	65,987	22,793	13,381	36,174	45	1,124	301	1,470
13	Total Expenses	2,268,079	2,268,079	664,839	422,352	1,087,191	1,454	21,497	10,406	33,357
14	Net Operating Income	470,213	470,213	162,422	95,350	257,773	324	8,009	2,141	10,475
15	Other Income Adjustments	9,378	9,378	2,640	1,644	4,284	6	39	32	77
16	Adjusted Net Operating Income	479,591	479,591	165,062	96,995	262,057	330	8,048	2,174	10,552
17	Return on Rate Base @ 6.12%	521,625	521,625	143,404	85,177	228,581	472	10,922	1,587	12,981
18	Income Deficiency (Sufficiency)	42,034	42,034	(21,658)	(11,817)	(33,475)	142	2,874	(587)	2,429
19	Revenue Deficiency (Sufficiency)	56,245	56,245	(28,980)	(15,812)	(44,793)	190	3,845	(786)	3,250
20	Additional Rev Requirement	6,557	6,557	4,331	3,580	7,912	(7)	(53)	97	38
21	Total Revenue Deficiency (Sufficiency)	62,802	62,802	(24,649)	(12,232)	(36,881)	183	3,792	(688)	3,287
22	Revenue Requirement/Total Cost of Service	2,801,094	2,801,094	802,612	505,471	1,308,082	1,961	33,299	11,859	47,119
23	Less: Revenue Credits	391,232	391,232	122,765	83,884	206,649	236	1,349	2,448	4,033
24	**Proposed Rate Design Revenue**	**2,409,862**	**2,409,862**	**679,847**	**421,586**	**1,101,433**	**1,725**	**31,950**	**9,411**	**43,086**
25	Production: Net Capacity Cost	488,807	488,807	143,402	91,125	234,527	8	-	1,868	1,876
26	Production: Capacity Related Cost Offset	114,259	114,259	37,719	26,534	64,254	89	434	894	1,416
27	Production: Non-Capacity Related Cost	450,843	450,843	152,392	104,690	257,082	304	1,433	3,159	4,897
28	Distribution: Demand Related Cost	1,168,664	1,168,664	310,449	190,159	500,609	1,249	28,759	3,407	33,415
29	Distribution: Customer Related Cost	187,288	187,288	35,884	9,078	44,962	76	1,324	82	1,482
30	Full Service MWH Sales	12,685,410	12,685,410	4,199,402	2,979,606	7,179,008	10,776	54,640	99,352	164,769
31	ROA MWH Sales	-	-	18,702	174,288	192,989	-	-	-	-
32	MWH Sales	12,685,410	12,685,410	4,218,104	3,153,894	7,371,997	10,776	54,640	99,352	164,769
33	Customers	1,680,798	1,680,798	206,948	20,624	227,572	399	4,696	465	5,560

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Rate Base**	180,796	37,586	70,625	706,412	94,322	248,052	579,492	567,193	24,917	7,032	1,458	2,517,886
2	**Revenue**												
3	Total Rate Revenue	76,037	37,506	44,499	345,089	86,707	126,526	248,155	538,702	21,956	4,550	732	1,530,460
4	Total Revenue Credits	17,695	11,059	12,141	85,459	26,994	35,069	61,972	182,990	7,745	1,245	159	442,529
5	Total Revenue	93,732	48,565	56,640	430,548	113,701	161,595	310,127	721,692	29,702	5,795	891	1,972,989
6	**Expenses:**												
7	Fuel and P&I Expense	37,710	23,671	26,079	182,799	57,178	74,202	130,263	389,872	16,701	2,657	358	941,490
8	Transmission Expense	13,734	7,489	8,599	63,872	17,691	23,748	42,211	113,129	5,271	830	129	296,705
9	Other O & M Expense	6,651	1,859	2,405	28,609	4,372	7,353	22,919	28,901	1,242	232	57	104,600
10	Depreciation & Amortization Expense	10,673	3,321	4,645	42,192	7,618	13,970	32,314	50,691	2,208	435	79	168,147
11	Other Taxes	4,738	1,533	2,248	20,293	4,054	7,653	16,298	21,385	848	232	43	79,324
12	Federal Income Taxes	2,489	1,316	1,558	11,418	2,804	4,266	8,137	14,486	422	173	28	47,100
13	Total Expenses	75,995	39,188	45,534	349,184	93,717	131,193	252,143	618,464	26,693	4,560	693	1,637,365
14	Net Operating Income	17,737	9,377	11,105	81,364	19,984	30,402	57,985	103,228	3,009	1,235	197	335,624
15	Other Income Adjustments	206	67	91	888	159	288	696	1,026	45	9	2	3,476
16	Adjusted Net Operating Income	17,943	9,444	11,197	82,253	20,143	30,690	58,680	104,253	3,054	1,244	199	339,100
17	Return on Rate Base @ 6.12%	11,058	2,299	4,320	43,206	5,769	15,171	35,443	34,691	1,524	430	89	154,000
18	Income Deficiency (Sufficiency)	(6,885)	(7,145)	(6,877)	(39,047)	(14,374)	(15,519)	(23,237)	(69,562)	(1,530)	(814)	(110)	(185,101)
19	Revenue Deficiency (Sufficiency)	(9,213)	(9,561)	(9,202)	(52,248)	(19,234)	(20,765)	(31,093)	(93,080)	(2,047)	(1,089)	(147)	(247,680)
20	Additional Rev Requirement	1,106	660	749	5,224	1,384	1,976	3,510	10,286	444	67	8	25,415
21	Total Revenue Deficiency (Sufficiency)	(8,107)	(8,901)	(8,454)	(47,024)	(17,850)	(18,789)	(27,583)	(82,794)	(1,603)	(1,022)	(139)	(222,265)
22	Revenue Requirement/Total Cost of Service	85,625	39,664	48,186	383,525	95,851	142,806	282,544	638,897	28,099	4,773	751	1,750,724
23	Less: Revenue Credits	17,695	11,059	12,141	85,459	26,994	35,069	61,972	182,990	7,745	1,245	159	442,529
24	**Proposed Rate Design Revenue**	**67,930**	**28,606**	**36,046**	**298,066**	**68,857**	**107,737**	**220,572**	**455,907**	**20,353**	**3,528**	**592**	**1,308,195**
25	Production: Net Capacity Cost	19,012	9,276	10,770	85,973	19,369	28,537	58,938	138,149	6,015	900	120	377,060
26	Production: Capacity Related Cost Offset	6,019	3,791	4,189	29,795	8,962	11,726	21,696	68,786	3,178	506	68	158,716
27	Production: Non-Capacity Related Cost	23,385	14,437	16,140	112,972	36,026	46,085	77,385	232,237	10,443	1,667	255	571,031
28	Distribution: Demand Related Cost	16,585	970	4,498	64,306	4,063	20,462	58,567	15,610	653	421	136	186,270
29	Distribution: Customer Related Cost	2,929	131	450	5,021	436	927	3,987	1,126	65	34	13	15,118
30	Full Service MWH Sales	666,952	464,518	496,642	3,312,240	1,167,540	1,453,040	2,414,780	7,884,000	332,592	53,237	6,737	18,252,279
31	ROA MWH Sales	72,068	-	-	-	1,270,576	1,080,207	953,091	-	-	-	-	3,375,942
32	MWH Sales	739,020	464,518	496,642	3,312,240	2,438,116	2,533,246	3,367,871	7,884,000	332,592	53,237	6,737	21,628,220
33	Customers	1,420	23	80	1,413	36	98	1,077	1	5	7	5	4,166

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Net Plant**						
2	Production	2,251,061	937,372	466,181	5,344	834,899	7,265
3	Transmission	-	-	-	-	-	-
4	Distribution	9,996,812	5,975,938	2,635,847	189,798	1,178,140	17,088
5	General/Common/Intangible	730,148	439,768	169,043	5,379	115,007	952
6	Plant Purchased/Sold	0	0	0	0	0	0
7	Total Net Plant	12,978,021	7,353,078	3,271,072	200,520	2,128,047	25,304
8	**Working Capital**						
9	Total Current Assets	3,131,271	1,789,157	725,531	27,596	584,484	4,504
10	Total Current Liabilities	1,019,384	592,374	249,206	15,723	160,409	1,671
11	Total Working Capital	2,111,887	1,196,782	476,325	11,872	424,074	2,833
	Adjustments to Rate Base						
13	Additions to Rate Base	0	0	0	0	0	0
14	Deductions from Rate Base	66,473	21,311	10,102	158	34,235	666
15	Total Adjustments to Rate Base	(66,473)	(21,311)	(10,102)	(158)	(34,235)	(666)
16	**Total Rate Base**	**15,023,435**	**8,528,549**	**3,737,295**	**212,235**	**2,517,886**	**27,471**
17	**Production Expense**						
18	Fuel Expense	551,095	185,515	106,533	2,335	254,355	2,356
19	Purchased & Interchange Power Expense	1,614,933	594,883	321,039	5,646	687,134	6,231
20	Total Fuel and P&I Expense	2,166,028	780,398	427,572	7,981	941,490	8,587
21	Fossil O&M Exp	55,255	22,231	11,290	152	21,392	190
22	Nuclear O&M Exp	0	-	-	-	-	-
23	Hydro O&M Exp	13,209	5,239	2,684	38	5,201	47
23	Other Power Gen O&M Exp	64,631	26,913	13,385	153	23,971	209
24	Other Power Supply O&M Exp	5,268	2,194	1,091	13	1,954	17
25	Total Production O&M Expense	138,363	56,577	28,450	356	52,518	462
26	Total Production (Inc. Fuel and P&I) O&M Expense	2,304,390	836,975	456,022	8,337	994,008	9,049
27	**Transmission & Distribution Expense**						
28	Transmission Expense	758,515	300,835	156,520	2,064	296,705	2,391
29	Direct Assign Transmission	0	-	-	-	-	-
30	Distr Oper Exp	115,755	78,108	28,712	3,444	5,452	38
31	Distr Maint Exp	354,948	238,522	91,773	1,452	23,002	198
32	Total Transmission & Distribution O&M Expense	1,229,218	617,465	277,005	6,961	325,159	2,628
33	**Customer Related Expense**						
34	Customer Accounts Exp	59,788	43,397	9,354	245	6,787	6
35	Customer Service Exp	7,158	4,032	1,071	25	2,014	16
36	Other Customer Exp	16,687	13,846	2,664	85	92	0
37	Total Customer O&M Expense	83,634	61,275	13,089	354	8,893	23
38	**Admin & General Expense**	93,510	56,307	21,657	689	14,734	122
39	**Total O&M Expense**	**3,710,752**	**1,572,022**	**767,773**	**16,341**	**1,342,795**	**11,822**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Net Plant**									
2	Production	937,372	937,372	282,186	183,995	466,181	174	822	4,348	5,344
3	Transmission	-	-	-	-	-	-	-	-	-
4	Distribution	5,975,938	5,975,938	1,663,937	971,910	2,635,847	6,634	166,451	16,713	189,798
5	General/Common/Intangible	439,768	439,768	106,539	62,504	169,043	270	3,887	1,222	5,379
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0
7	Total Net Plant	7,353,078	7,353,078	2,052,662	1,218,410	3,271,072	7,078	171,160	22,283	200,520
8	**Working Capital**									
9	Total Current Assets	1,789,157	1,789,157	455,169	270,363	725,531	1,195	20,960	5,441	27,596
10	Total Current Liabilities	592,374	592,374	156,960	92,246	249,206	535	13,475	1,713	15,723
11	Total Working Capital	1,196,782	1,196,782	298,209	178,116	476,325	660	7,485	3,728	11,872
	Adjustments to Rate Base									
13	Additions to Rate Base	0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base	21,311	21,311	6,221	3,881	10,102	18	71	69	158
15	Total Adjustments to Rate Base	(21,311)	(21,311)	(6,221)	(3,881)	(10,102)	(18)	(71)	(69)	(158)
16	**Total Rate Base**	**8,528,549**	**8,528,549**	**2,344,649**	**1,392,645**	**3,737,295**	**7,719**	**178,573**	**25,942**	**212,235**
17	**Production Expense**									
18	Fuel Expense	185,515	185,515	62,486	44,048	106,533	147	747	1,441	2,335
19	Purchased & Interchange Power Expense	594,883	594,883	190,799	130,240	321,039	308	1,554	3,784	5,646
20	Total Fuel and P&I Expense	780,398	780,398	253,284	174,288	427,572	455	2,301	5,225	7,981
21	Fossil O&M Exp	22,231	22,231	6,795	4,495	11,290	6	31	114	152
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	5,239	5,239	1,612	1,073	2,684	2	9	28	38
23	Other Power Gen O&M Exp	26,913	26,913	8,102	5,283	13,385	5	24	125	153
24	Other Power Supply O&M Exp	2,194	2,194	660	431	1,091	0	2	10	13
25	Total Production O&M Expense	56,577	56,577	17,169	11,281	28,450	14	65	277	356
26	Total Production (Inc. Fuel and P&I) O&M Expense	836,975	836,975	270,453	185,569	456,022	468	2,366	5,502	8,337
27	**Transmission & Distribution Expense**									
28	Transmission Expense	300,835	300,835	94,589	61,931	156,520	113	434	1,518	2,064
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	78,108	78,108	17,893	10,820	28,712	91	3,157	197	3,444
31	Distr Maint Exp	238,522	238,522	57,693	34,079	91,773	157	698	597	1,452
32	Total Transmission & Distribution O&M Expense	617,465	617,465	170,175	106,830	277,005	361	4,288	2,312	6,961
33	**Customer Related Expense**									
34	Customer Accounts Exp	43,397	43,397	7,101	2,253	9,354	15	180	50	245
35	Customer Service Exp	4,032	4,032	743	328	1,071	2	13	10	25
36	Other Customer Exp	13,846	13,846	2,346	318	2,664	6	71	7	85
37	Total Customer O&M Expense	61,275	61,275	10,189	2,899	13,089	22	265	67	354
38	**Admin & General Expense**	56,307	56,307	13,649	8,008	21,657	35	498	157	689
39	**Total O&M Expense**	**1,572,022**	**1,572,022**	**464,466**	**303,307**	**767,773**	**886**	**7,417**	**8,037**	**16,341**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Net Plant**												
2	Production	38,728	20,769	23,594	179,467	44,678	63,274	125,013	323,040	13,914	2,141	282	834,899
3	Transmission	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	112,859	6,742	34,195	395,406	29,949	149,298	354,556	86,126	4,414	3,668	928	1,178,140
5	General/Common/Intangible	6,931	2,200	2,811	30,141	5,084	8,452	23,611	33,989	1,464	266	57	115,007
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Net Plant	158,518	29,711	60,600	605,014	79,711	221,023	503,180	443,155	19,792	6,076	1,267	2,128,047
8	**Working Capital**												
9	Total Current Assets	34,007	11,748	15,250	146,879	27,321	46,042	113,553	180,206	7,709	1,483	285	584,484
10	Total Current Liabilities	11,444	2,482	4,370	44,721	6,297	15,088	36,552	37,291	1,639	432	92	160,409
11	Total Working Capital	22,564	9,266	10,880	102,157	21,023	30,954	77,001	142,915	6,070	1,051	193	424,074
	Adjustments to Rate Base												
13	Additions to Rate Base	0	0	0	0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base	286	1,391	856	760	6,412	3,925	689	18,877	944	94	2	34,235
15	Total Adjustments to Rate Base	(286)	(1,391)	(856)	(760)	(6,412)	(3,925)	(689)	(18,877)	(944)	(94)	(2)	(34,235)
16	**Total Rate Base**	**180,796**	**37,586**	**70,625**	**706,412**	**94,322**	**248,052**	**579,492**	**567,193**	**24,917**	**7,032**	**1,458**	**2,517,886**
17	**Production Expense**												
18	Fuel Expense	9,642	6,418	6,997	47,593	16,069	20,307	34,212	107,671	4,604	740	101	254,355
19	Purchased & Interchange Power Expense	28,068	17,253	19,081	135,206	41,109	53,894	96,051	282,201	12,096	1,917	258	687,134
20	Total Fuel and P&I Expense	37,710	23,671	26,079	182,799	57,178	74,202	130,263	389,872	16,701	2,657	358	941,490
21	Fossil O&M Exp	951	535	601	4,464	1,167	1,622	3,135	8,488	364	57	7	21,392
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	227	130	146	1,073	286	395	756	2,084	89	14	2	5,201
23	Other Power Gen O&M Exp	1,112	596	677	5,153	1,283	1,817	3,589	9,275	399	61	8	23,971
24	Other Power Supply O&M Exp	91	49	55	420	105	148	293	756	33	5	1	1,954
25	Total Production O&M Expense	2,381	1,310	1,480	11,110	2,840	3,982	7,773	20,603	885	137	18	52,518
26	Total Production (Inc. Fuel and P&I) O&M Expense	40,091	24,981	27,559	193,909	60,018	78,183	138,036	410,475	17,586	2,794	376	994,008
27	**Transmission & Distribution Expense**												
28	Transmission Expense	13,734	7,489	8,599	63,872	17,691	23,748	42,211	113,129	5,271	830	129	296,705
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	489	6	21	2,377	41	172	2,193	140	6	3	5	5,452
31	Distr Maint Exp	2,453	51	300	9,410	226	1,322	8,502	651	33	32	22	23,002
32	Total Transmission & Distribution O&M Expense	16,676	7,546	8,920	75,659	17,958	25,242	52,906	113,920	5,310	866	157	325,159
33	**Customer Related Expense**												
34	Customer Accounts Exp	347	166	196	1,513	386	556	1,090	2,412	99	20	3	6,787
35	Customer Service Exp	71	43	46	310	226	235	314	732	31	5	1	2,014
36	Other Customer Exp	23	1	2	29	2	4	22	9	0	0	0	92
37	Total Customer O&M Expense	441	210	244	1,851	614	795	1,426	3,153	130	25	4	8,893
38	**Admin & General Expense**	888	282	360	3,862	651	1,083	3,025	4,355	188	34	7	14,734
39	**Total O&M Expense**	**58,095**	**33,019**	**37,083**	**275,281**	**79,241**	**105,303**	**195,394**	**531,902**	**23,214**	**3,719**	**544**	**1,342,795**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
	Input Allocation Schedules						
1	Energy @ Generation	100.000	33.906	19.188	0.440	46.025	0.441
2	Energy On-Peak @ Generation	100.000	32.760	20.818	0.340	45.730	0.351
3	Energy Off-Peak @ Generation	100.000	34.750	17.300	0.540	46.880	0.530
4	Energy On-Peak @ Generation Summer	100.000	34.135	21.405	0.284	43.813	0.363
5	Energy Off-Peak @ Generation Summer	100.000	35.421	17.712	0.487	45.800	0.579
6	Energy On-Peak @ Generation Non-Summer	100.000	31.974	20.483	0.372	46.826	0.344
7	Energy Off-Peak @ Generation Non-Summer	100.000	34.385	17.075	0.569	47.467	0.504
8	Energy Critical On-Peak @ Gen	100.000	36.621	21.818	0.218	41.083	0.259
9	Energy Summer Mid-Peak @ Gen	100.000	33.229	21.254	0.308	44.809	0.401
10	12CP Dmd @ Generation	100.000	39.661	20.635	0.272	39.117	0.315
11	4CP Dmd @ Generation	100.000	44.220	21.216	0.170	34.111	0.283
12	Class Peak @ Voltage 1	100.000	41.935	19.878	0.312	37.315	0.561
13	Production Revenue	100.000	37.294	20.190	0.336	42.222	(0.042)
14	Distribution Revenue	100.000	61.655	26.328	1.586	10.271	0.160
15	Total Rate Revenue	100.000	45.705	22.309	0.768	31.190	0.028
16	Billed Sales	100.000	30.186	17.542	0.392	51.467	0.412
17	Number Of Customers	100.000	87.628	11.864	0.290	0.217	0.001
18	Weighted Customer	100.000	60.166	28.619	0.054	11.124	0.038
		-					
	*Calculated Allocation Schedules						
19	4CP 75/0/25	100.000	41.641	20.709	0.237	37.089	0.323
20	Class Peak @ Voltage 2	100.000	50.207	23.799	0.373	24.949	0.672
21	Class Peak Voltage 1 Only	100.000	-	-	-	98.503	1.497
22	Class Peak Voltage 2 Only	100.000	-	-	-	95.387	4.613
23	Class Peak @ Voltage 1 excluding Voltage 2	100.000	44.342	21.019	0.329	33.982	0.329
24	Class Peak @ Voltage 3	100.000	53.875	25.538	0.400	20.109	0.077
25	Class Peak @ Voltage 4	100.000	67.502	31.997	0.501	-	-
26	Class Peak for Streetlighting	100.000	-	-	100.000	-	-
27	Class Peak @ Single Phase	100.000	67.502	31.997	0.501	-	-
28	Billed Sales - Primary	100.000	45.911	26.681	0.596	26.744	0.067
29	Customers - Residential	100.000	100.000	-	-	-	-
30	Customers - Commercial Secondary	100.000	-	100.000	-	-	-
31	Customers - Non-Primary	100.000	88.057	11.922	0.021	-	-
32	Customers - Non-Lighting	100.000	87.883	11.899	-	0.218	0.001
33	Customers - Commercial & Primary	100.000	-	98.196	-	1.798	0.006
34	Customer Count (CCC)	100.000	93.559	6.441	-	-	-
35	Customer Count (BCC)	100.000	-	91.990	4.572	3.426	0.012
36	PIS - HVD (Voltage 1)	100.000	50.168	23.781	0.373	25.071	0.607
37	PIS - HVD (Voltage 2)	100.000	50.117	23.756	0.372	25.218	0.537
38	PIS - HVD (Voltage 1) Substations	100.000	50.207	23.799	0.373	24.949	0.672
39	PIS - HVD (Voltage 2) Substations	100.000	41.526	19.684	0.309	37.365	1.117
40	PIS - OH LVD System	100.000	63.654	30.173	0.473	5.678	0.022
41	PIS - LVD Distribution	100.000	63.001	26.146	2.447	8.323	0.082
42	PIS- OH (LVD & HVD) Lines & Services	100.000	66.214	25.689	0.389	7.625	0.083
43	PIS- UG LVD Distribution	100.000	63.298	30.005	0.470	6.184	0.043
44	PIS- Total Distribution	100.000	61.233	25.819	2.162	10.638	0.148

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
	Input Allocation Schedules									
1	Energy @ Generation	33.906	33.906	11.224	7.964	19.188	0.029	0.146	0.266	0.440
2	Energy On-Peak @ Generation	32.760	32.760	12.407	8.412	20.818	0.015	0.078	0.248	0.340
3	Energy Off-Peak @ Generation	34.750	34.750	9.882	7.418	17.300	0.043	0.215	0.282	0.540
4	Energy On-Peak @ Generation Summer	34.135	34.135	12.788	8.616	21.405	0.007	0.048	0.229	0.284
5	Energy Off-Peak @ Generation Summer	35.421	35.421	10.126	7.587	17.712	0.036	0.187	0.264	0.487
6	Energy On-Peak @ Generation Non-Summer	31.974	31.974	12.189	8.295	20.483	0.019	0.095	0.258	0.372
7	Energy Off-Peak @ Generation Non-Summer	34.385	34.385	9.749	7.326	17.075	0.047	0.230	0.291	0.569
8	Energy Critical On-Peak @ Gen	36.621	36.621	13.089	8.729	21.818	0.001	0.003	0.214	0.218
9	Energy Summer Mid-Peak @ Gen	33.229	33.229	12.679	8.575	21.254	0.009	0.065	0.234	0.308
10	12CP Dmd @ Generation	39.661	39.661	12.470	8.165	20.635	0.015	0.057	0.200	0.272
11	4CP Dmd @ Generation	44.220	44.220	12.973	8.244	21.216	0.001	-	0.169	0.170
12	Class Peak @ Voltage 1	41.935	41.935	12.242	7.636	19.878	0.035	0.141	0.136	0.312
13	Production Revenue	37.294	37.294	12.000	8.190	20.190	0.018	0.089	0.229	0.336
14	Distribution Revenue	61.655	61.655	17.136	9.192	26.328	0.053	1.379	0.154	1.586
15	Total Rate Revenue	45.705	45.705	13.773	8.536	22.309	0.030	0.535	0.203	0.768
16	Billed Sales	30.186	30.186	10.037	7.505	17.542	0.026	0.130	0.236	0.392
17	Number Of Customers	87.628	87.628	10.789	1.075	11.864	0.021	0.245	0.024	0.290
18	Weighted Customer	60.166	60.166	23.310	5.309	28.619	0.054	-	-	0.054
	*Calculated Allocation Schedules									
19	4CP 75/0/25	41.641	41.641	12.536	8.174	20.709	0.008	0.037	0.193	0.237
20	Class Peak @ Voltage 2	50.207	50.207	14.657	9.142	23.799	0.042	0.168	0.163	0.373
21	Class Peak Voltage 1 Only	-	-	-	-	-	-	-	-	-
22	Class Peak Voltage 2 Only	-	-	-	-	-	-	-	-	-
23	Class Peak @ Voltage 1 excluding Voltage 2	44.342	44.342	12.944	8.074	21.019	0.037	0.149	0.144	0.329
24	Class Peak @ Voltage 3	53.875	53.875	15.728	9.810	25.538	0.045	0.181	0.175	0.400
25	Class Peak @ Voltage 4	67.502	67.502	19.705	12.291	31.997	0.056	0.226	0.219	0.501
26	Class Peak for Streetlighting	-	-	-	-	-	19.934	80.066	-	100.000
27	Class Peak @ Single Phase	67.502	67.502	19.705	12.291	31.997	0.056	0.226	0.219	0.501
28	Billed Sales - Primary	45.911	45.911	15.266	11.415	26.681	0.039	0.198	0.360	0.596
29	Customers - Residential	100.000	100.000	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	90.937	9.063	100.000	-	-	-	-
31	Customers - Non-Primary	88.057	88.057	10.842	1.080	11.922	0.021	-	-	0.021
32	Customers - Non-Lighting	87.883	87.883	10.821	1.078	11.899	-	-	-	-
33	Customers - Commercial & Primary	-	-	89.297	8.899	98.196	-	-	-	-
34	Customer Count (CCC)	93.559	93.559	6.388	0.054	6.441	-	-	-	-
35	Customer Count (BCC)	-	-	75.820	16.170	91.990	0.328	3.862	0.382	4.572
36	PIS - HVD (Voltage 1)	50.168	50.168	14.645	9.135	23.781	0.042	0.168	0.163	0.373
37	PIS - HVD (Voltage 2)	50.117	50.117	14.630	9.126	23.756	0.042	0.168	0.162	0.372
38	PIS - HVD (Voltage 1) Substations	50.207	50.207	14.657	9.142	23.799	0.042	0.168	0.163	0.373
39	PIS - HVD (Voltage 2) Substations	41.526	41.526	12.122	7.562	19.684	0.035	0.139	0.135	0.309
40	PIS - OH LVD System	63.654	63.654	18.582	11.591	30.173	0.053	0.214	0.206	0.473
41	PIS - LVD Distribution	63.001	63.001	16.653	9.493	26.146	0.073	2.212	0.162	2.447
42	PIS- OH (LVD & HVD) Lines & Services	66.214	66.214	16.075	9.615	25.689	0.044	0.176	0.170	0.389
43	PIS- UG LVD Distribution	63.298	63.298	18.478	11.526	30.005	0.053	0.212	0.205	0.470
44	PIS- Total Distribution	61.233	61.233	16.375	9.443	25.819	0.069	1.931	0.162	2.162

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
	Input Allocation Schedules												
1	Energy @ Generation	1.722	1.173	1.269	8.558	2.682	3.499	6.219	19.909	0.840	0.136	0.017	46.025
2	Energy On-Peak @ Generation	2.000	1.160	1.329	9.499	2.836	3.657	6.202	18.040	0.851	0.130	0.025	45.730
3	Energy Off-Peak @ Generation	1.416	1.174	1.194	7.494	3.035	3.736	6.213	21.648	0.819	0.141	0.009	46.880
4	Energy On-Peak @ Generation Summer	2.009	1.118	1.278	9.422	2.701	3.496	6.271	16.597	0.780	0.118	0.023	43.813
5	Energy Off-Peak @ Generation Summer	1.437	1.147	1.185	7.606	2.971	3.626	6.397	20.508	0.781	0.132	0.009	45.800
6	Energy On-Peak @ Generation Non-Summer	1.994	1.184	1.358	9.542	2.913	3.749	6.163	18.866	0.892	0.137	0.027	46.826
7	Energy Off-Peak @ Generation Non-Summer	1.405	1.189	1.199	7.432	3.070	3.796	6.113	22.268	0.840	0.146	0.009	47.467
8	Energy Critical On-Peak @ Gen	1.888	1.020	1.178	8.935	2.415	3.260	6.013	15.530	0.733	0.098	0.013	41.083
9	Energy Summer Mid-Peak @ Gen	2.053	1.154	1.315	9.600	2.805	3.582	6.365	16.986	0.797	0.125	0.027	44.809
10	12CP Dmd @ Generation	1.811	0.987	1.134	8.421	2.332	3.131	5.565	14.915	0.695	0.109	0.017	39.117
11	4CP Dmd @ Generation	1.720	0.839	0.974	7.778	1.752	2.582	5.332	12.498	0.544	0.081	0.011	34.111
12	Class Peak @ Voltage 1	1.911	0.829	0.894	7.253	3.822	4.100	6.575	11.253	0.563	0.099	0.017	37.315
13	Production Revenue	1.755	1.131	1.235	8.407	2.586	3.394	5.839	17.078	0.676	0.108	0.014	42.222
14	Distribution Revenue	1.063	0.075	0.271	4.104	0.268	1.010	3.356	-	0.043	0.064	0.016	10.271
15	Total Rate Revenue	1.516	0.767	0.902	6.921	1.786	2.571	4.982	11.181	0.457	0.093	0.015	31.190
16	Billed Sales	1.759	1.105	1.182	7.882	5.802	6.028	8.014	18.761	0.791	0.127	0.016	51.467
17	Number Of Customers	0.074	0.001	0.004	0.074	0.002	0.005	0.056	0.000	0.000	0.000	0.000	0.217
18	Weighted Customer	3.005	0.071	0.361	4.140	0.125	0.303	3.065	0.004	0.019	0.021	0.011	11.124
		-	-	-	-	-	-	-	-	-	-	-	-
	*Calculated Allocation Schedules	-	-	-	-	-	-	-	-	-	-	-	-
19	4CP 75/0/25	1.720	0.923	1.048	7.973	1.985	2.811	5.554	14.351	0.618	0.095	0.013	37.089
20	Class Peak @ Voltage 2	2.277	-	1.070	8.684	-	4.908	7.871	-	-	0.118	0.020	24.949
21	Class Peak Voltage 1 Only	0.053	4.956	-	-	22.853	-	-	67.276	3.366	-	-	98.503
22	Class Peak Voltage 2 Only	1.574	-	16.464	-	-	75.532	-	-	-	1.817	-	95.387
23	Class Peak @ Voltage 1 excluding Voltage 2	1.930	0.876	-	7.670	4.042	-	6.952	11.899	0.595	-	0.018	33.982
24	Class Peak @ Voltage 3	2.323	-	-	9.318	-	-	8.447	-	-	-	0.022	20.109
25	Class Peak @ Voltage 4	-	-	-	-	-	-	-	-	-	-	-	-
26	Class Peak for Streetlighting	-	-	-	-	-	-	-	-	-	-	-	-
27	Class Peak @ Single Phase	-	-	-	-	-	-	-	-	-	-	-	-
28	Billed Sales - Primary	2.543	-	-	11.988	-	-	12.189	-	-	-	0.024	26.744
29	Customers - Residential	-	-	-	-	-	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	-	-	-	-	-	-	-	-	-	-
31	Customers - Non-Primary	-	-	-	-	-	-	-	-	-	-	-	-
32	Customers - Non-Lighting	0.074	0.001	0.004	0.074	0.002	0.005	0.056	0.000	0.000	0.000	0.000	0.218
33	Customers - Commercial & Primary	0.613	0.010	0.035	0.610	0.016	0.042	0.465	0.000	0.002	0.003	0.002	1.798
34	Customer Count (CCC)	-	-	-	-	-	-	-	-	-	-	-	-
35	Customer Count (BCC)	1.168	0.019	0.066	1.162	0.030	0.080	0.886	0.001	0.004	0.006	0.004	3.426
36	PIS - HVD (Voltage 1)	2.263	0.042	0.949	8.677	0.195	4.352	7.865	0.574	0.029	0.105	0.020	25.071
37	PIS - HVD (Voltage 2)	1.945	-	1.687	7.157	-	7.739	6.487	-	-	0.186	0.017	25.218
38	PIS - HVD (Voltage 1) Substations	2.277	-	1.070	8.684	-	4.908	7.871	-	-	0.118	0.020	24.949
39	PIS - HVD (Voltage 2) Substations	2.151	-	3.774	7.182	-	17.314	6.510	-	-	0.417	0.017	37.365
40	PIS - OH LVD System	0.656	-	-	2.631	-	-	2.385	-	-	-	0.006	5.678
41	PIS - LVD Distribution	0.889	0.065	0.116	2.990	0.285	0.441	2.663	0.814	0.042	0.012	0.007	8.323
42	PIS- OH (LVD & HVD) Lines & Services	0.774	0.014	0.129	3.054	0.067	0.592	2.768	0.196	0.010	0.014	0.007	7.625
43	PIS- UG LVD Distribution	0.556	0.067	0.008	2.223	0.311	0.037	2.015	0.915	0.046	0.001	0.005	6.184
44	PIS- Total Distribution	1.049	0.058	0.297	3.635	0.255	1.284	3.254	0.729	0.038	0.032	0.009	10.638

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	*Calculated Allocation Schedules						
2	PIS- Distribution Services	100.000	94.121	5.879	-	-	-
3	PIS- Streetlighting Equipment	100.000	-	-	100.000	-	-
4	PIS- Line Equipment	100.000	66.184	31.372	0.492	1.944	0.007
5	PIS- Meters	100.000	60.166	28.619	0.054	11.124	0.038
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000
7	Total PIS	100.000	57.142	24.573	1.661	16.442	0.183
8	Distribution Depreciation	100.000	64.795	24.617	2.708	7.788	0.092
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	100.000	34.944	16.564	0.260	47.656	0.576
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	100.000	50.502	23.939	0.375	24.694	0.491
11	PIS- LVD OH Lines & Services	100.000	68.843	26.036	0.392	4.711	0.018
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	100.000	-	-	-	98.503	1.497
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	100.000	52.165	24.727	0.388	22.394	0.327
14	CWIP	100.000	54.360	24.832	0.448	20.151	0.209
15	Rate Base- Total	100.000	56.768	24.876	1.413	16.760	0.183
16	Dist Op Expense (LVD) excl Sup & Eng	100.000	67.911	24.847	3.035	4.185	0.022
17	Dist Maint Expense (LVD) excl Sup & Eng	100.000	68.695	26.092	0.413	4.781	0.018
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.047	21.353	0.335	32.739	0.525
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.522	21.578	0.338	32.038	0.523
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.626	23.524	0.369	25.955	0.526
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.354	23.395	0.367	26.347	0.537
22	Total HVD Distribution O&M Expense	100.000	48.212	22.853	0.358	28.044	0.532
23	Total Distribution O&M Expense (excl. HVD)	100.000	68.541	25.773	1.077	4.590	0.018
24	Total Customer Accounts Expense (excl. Supv)	100.000	72.584	15.645	0.410	11.351	0.010
25	Total Customer Accounts & Service Expense	100.000	70.846	15.571	0.403	13.147	0.033
26	Pre Tax NOI	100.000	43.580	23.891	0.971	31.106	0.452
27	Depreciation & Amortization Expense	100.000	53.690	23.486	1.687	20.937	0.199
28	Non PSCR O&M Expense	100.000	62.425	23.363	0.801	13.304	0.107
29	Distribution Depreciation Expense	100.000	61.447	25.637	2.973	9.819	0.123
30	Gen/Comm/Int Depreciation Expense	100.000	60.215	23.161	0.737	15.757	0.130
31	Production Labor	100.000	41.641	20.709	0.237	37.089	0.323
32	Total Labor	100.000	60.215	23.161	0.737	15.757	0.130
33	50% O&M, 50% Net Plant	100.000	53.480	24.201	1.299	20.797	0.222
34	50/50 PIS & Labor	100.000	58.678	23.867	1.199	16.099	0.156

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	*Calculated Allocation Schedules									
2	PIS- Distribution Services	94.121	94.121	5.347	0.533	5.879	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	1.423	98.577	-	100.000
4	PIS- Line Equipment	66.184	66.184	19.321	12.052	31.372	0.055	0.222	0.214	0.492
5	PIS- Meters	60.166	60.166	23.310	5.309	28.619	0.054	-	-	0.054
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Total PIS	57.142	57.142	15.455	9.117	24.573	0.054	1.439	0.169	1.661
8	Distribution Depreciation	64.795	64.795	15.775	8.842	24.617	0.074	2.484	0.150	2.708
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	34.944	34.944	10.201	6.363	16.564	0.029	0.117	0.113	0.260
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	50.502	50.502	14.743	9.196	23.939	0.042	0.169	0.164	0.375
11	PIS- LVD OH Lines & Services	68.843	68.843	16.328	9.708	26.036	0.044	0.177	0.171	0.392
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	-	-	-	-	-	-	-	-	-
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	52.165	52.165	15.228	9.499	24.727	0.044	0.175	0.169	0.388
14	CWIP	54.360	54.360	15.302	9.530	24.832	0.034	0.226	0.188	0.448
15	Rate Base- Total	56.768	56.768	15.607	9.270	24.876	0.051	1.189	0.173	1.413
16	Dist Op Expense (LVD) excl Sup & Eng	67.911	67.911	15.488	9.359	24.847	0.080	2.785	0.170	3.035
17	Dist Maint Expense (LVD) excl Sup & Eng	68.695	68.695	16.426	9.666	26.092	0.045	0.199	0.169	0.413
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	45.047	45.047	13.151	8.203	21.353	0.038	0.151	0.146	0.335
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	45.522	45.522	13.289	8.289	21.578	0.038	0.153	0.147	0.338
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	49.626	49.626	14.487	9.037	23.524	0.041	0.166	0.161	0.369
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	49.354	49.354	14.408	8.987	23.395	0.041	0.166	0.160	0.367
22	Total HVD Distribution O&M Expense	48.212	48.212	14.074	8.779	22.853	0.040	0.162	0.156	0.358
23	Total Distribution O&M Expense (excl. HVD)	68.541	68.541	16.185	9.589	25.773	0.053	0.854	0.170	1.077
24	Total Customer Accounts Expense (excl. Supv)	72.584	72.584	11.876	3.769	15.645	0.024	0.301	0.084	0.410
25	Total Customer Accounts & Service Expense	70.846	70.846	11.716	3.855	15.571	0.024	0.289	0.090	0.403
26	Pre Tax NOI	43.580	43.580	15.054	8.837	23.891	0.030	0.742	0.198	0.971
27	Depreciation & Amortization Expense	53.690	53.690	14.839	8.648	23.486	0.048	1.472	0.168	1.687
28	Non PSCR O&M Expense	62.425	62.425	14.830	8.533	23.363	0.041	0.596	0.165	0.801
29	Distribution Depreciation Expense	61.447	61.447	16.618	9.019	25.637	0.080	2.745	0.148	2.973
30	Gen/Comm/Int Depreciation Expense	60.215	60.215	14.597	8.564	23.161	0.037	0.533	0.167	0.737
31	Production Labor	41.641	41.641	12.536	8.174	20.709	0.008	0.037	0.193	0.237
32	Total Labor	60.215	60.215	14.597	8.564	23.161	0.037	0.533	0.167	0.737
33	50% O&M, 50% Net Plant	53.480	53.480	15.083	9.118	24.201	0.048	1.070	0.182	1.299
34	50/50 PIS & Labor	58.678	58.678	15.026	8.841	23.867	0.045	0.986	0.168	1.199

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	*Calculated Allocation Schedules												
2	PIS- Distribution Services	-	-	-	-	-	-	-	-	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	-	-	-	-	-	-	-
4	PIS- Line Equipment	0.225	-	-	0.901	-	-	0.817	-	-	-	0.002	1.944
5	PIS- Meters	3.005	0.071	0.361	4.140	0.125	0.303	3.065	0.004	0.019	0.021	0.011	11.124
6	PIS - General	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Total PIS	1.179	0.253	0.458	4.561	0.642	1.588	3.724	3.814	0.169	0.045	0.009	16.442
8	Distribution Depreciation	0.842	0.035	0.181	2.838	0.148	0.751	2.531	0.413	0.022	0.019	0.007	7.788
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	1.527	1.741	-	6.044	8.030	-	5.479	23.639	1.183	-	0.014	47.656
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	2.278	-	1.008	8.735	-	4.623	7.918	-	-	0.111	0.020	24.694
11	PIS- LVD OH Lines & Services	0.544	-	-	2.183	-	-	1.979	-	-	-	0.005	4.711
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	0.053	4.956	-	-	22.853	-	-	67.276	3.366	-	-	98.503
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	2.301	-	0.504	9.023	-	2.311	8.178	-	-	0.056	0.021	22.394
14	CWIP	1.195	0.387	0.529	5.148	0.924	1.669	4.033	5.945	0.259	0.051	0.010	20.151
15	Rate Base- Total	1.203	0.250	0.470	4.702	0.628	1.651	3.857	3.775	0.166	0.047	0.010	16.760
16	Dist Op Expense (LVD) excl Sup & Eng	0.382	0.001	(0.005)	1.910	0.016	0.043	1.765	0.065	0.002	0.000	0.004	4.185
17	Dist Maint Expense (LVD) excl Sup & Eng	0.573	0.001	0.004	2.203	0.002	0.004	1.989	0.000	0.000	0.000	0.005	4.781
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	1.998	0.666	0.463	7.792	3.071	2.124	7.063	9.041	0.452	0.051	0.018	32.739
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	2.020	0.615	0.485	7.874	2.838	2.224	7.137	8.355	0.418	0.054	0.018	32.038
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	2.265	-	1.282	8.584	-	5.882	7.780	-	-	0.142	0.020	25.955
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	2.261	-	1.367	8.537	-	6.273	7.738	-	-	0.151	0.020	26.347
22	Total HVD Distribution O&M Expense	2.189	0.186	1.097	8.339	0.856	5.033	7.559	2.519	0.126	0.121	0.019	28.044
23	Total Distribution O&M Expense (excl. HVD)	0.521	0.001	0.000	2.119	0.004	0.006	1.923	0.012	0.001	0.000	0.005	4.590
24	Total Customer Accounts Expense (excl. Supv)	0.580	0.277	0.327	2.530	0.645	0.930	1.823	4.035	0.165	0.034	0.005	11.351
25	Total Customer Accounts & Service Expense	0.624	0.312	0.361	2.722	0.914	1.182	2.097	4.696	0.194	0.037	0.006	13.147
26	Pre Tax NOI	1.644	0.869	1.029	7.541	1.852	2.818	5.374	9.567	0.279	0.115	0.018	31.106
27	Depreciation & Amortization Expense	1.329	0.413	0.578	5.254	0.949	1.740	4.024	6.312	0.275	0.054	0.010	20.937
28	Non PSCR O&M Expense	0.846	0.236	0.306	3.639	0.556	0.935	2.915	3.676	0.158	0.030	0.007	13.304
29	Distribution Depreciation Expense	1.112	0.052	0.263	3.434	0.217	1.048	3.031	0.595	0.032	0.027	0.008	9.819
30	Gen/Comm/Int Depreciation Expense	0.950	0.301	0.385	4.130	0.697	1.158	3.235	4.657	0.201	0.036	0.008	15.757
31	Production Labor	1.720	0.923	1.048	7.973	1.985	2.811	5.554	14.351	0.618	0.095	0.013	37.089
32	Total Labor	0.950	0.301	0.385	4.130	0.697	1.158	3.235	4.657	0.201	0.036	0.008	15.757
33	50% O&M, 50% Net Plant	1.298	0.376	0.585	5.275	0.952	1.955	4.186	5.843	0.258	0.059	0.011	20.797
34	50/50 PIS & Labor	1.064	0.277	0.421	4.345	0.669	1.373	3.479	4.235	0.185	0.041	0.009	16.099

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Rate Base**	15,023,435	8,422,887	3,723,820	214,608	2,633,908	28,213
2	**Revenue**						
3	Total Rate Revenue	5,057,111	2,347,060	1,138,314	39,799	1,530,460	1,478
4	Total Revenue Credits	1,062,868	380,299	205,255	4,279	454,534	18,502
5	Total Revenue	6,119,980	2,727,358	1,343,569	44,078	1,984,994	19,980
6	**Expenses:**						
7	Fuel and P&I Expense	2,166,028	758,435	424,771	8,474	965,606	8,741
8	Transmission Expense	758,515	300,835	156,520	2,064	296,705	2,391
9	Other O & M Expense	786,210	485,614	183,021	6,412	110,282	880
10	Depreciation & Amortization Expense	803,119	419,962	187,191	13,805	180,483	1,678
11	Other Taxes	375,732	197,642	94,462	2,021	80,677	929
12	Federal Income Taxes	151,415	69,515	36,624	1,391	43,225	660
13	Total Expenses	5,041,018	2,232,003	1,082,590	34,167	1,676,978	15,279
14	Net Operating Income	1,078,962	495,355	260,979	9,910	308,017	4,701
15	Other Income Adjustments	17,252	9,158	4,256	82	3,718	38
16	Adjusted Net Operating Income	1,096,214	504,513	265,235	9,992	311,735	4,739
17	Return on Rate Base @ 6.12%	918,867	515,163	227,757	13,126	161,096	1,726
18	Income Deficiency (Sufficiency)	(177,347)	10,650	(37,478)	3,134	(150,639)	(3,013)
19	Revenue Deficiency (Sufficiency)	(237,305)	14,250	(50,148)	4,193	(201,567)	(4,032)
20	Additional Rev Requirement	40,158	3,943	7,578	96	28,285	256
21	Total Revenue Deficiency (Sufficiency)	(197,146)	18,193	(42,570)	4,289	(173,282)	(3,776)
22	Revenue Requirement/Total Cost of Service	5,922,834	2,745,551	1,300,999	48,367	1,811,712	16,204
23	Less: Revenue Credits	1,062,868	380,299	205,255	4,279	454,534	18,502
24	**Proposed Rate Design Revenue**	**4,859,965**	**2,365,252**	**1,095,744**	**44,088**	**1,357,178**	**(2,298)**
25	Production: Net Capacity Cost	1,105,401	438,413	228,100	3,008	432,395	3,485
26	Production: Capacity Related Cost Offset	339,952	109,110	63,597	1,532	164,369	1,343
27	Production: Non-Capacity Related Cost	1,274,471	461,777	258,476	4,651	559,026	(9,458)
28	Distribution: Demand Related Cost	1,891,196	1,168,664	500,609	33,415	186,270	2,238
29	Distribution: Customer Related Cost	248,945	187,288	44,962	1,482	15,118	95
30	Full Service MWH Sales	38,454,766	12,685,410	7,179,008	164,769	18,252,279	173,301
31	ROA MWH Sales	3,568,931	-	192,989	-	3,375,942	-
32	MWH Sales	42,023,697	12,685,410	7,371,997	164,769	21,628,220	173,301
33	Customers	1,918,109	1,680,798	227,572	5,560	4,166	14

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Rate Base**	8,422,887	8,422,887	2,333,000	1,390,819	3,723,820	8,048	179,899	26,662	214,608
2	**Revenue**									
3	Total Rate Revenue	2,347,060	2,347,060	704,496	433,818	1,138,314	1,542	28,157	10,099	39,799
4	Total Revenue Credits	380,299	380,299	121,559	83,695	205,255	270	1,486	2,523	4,279
5	Total Revenue	2,727,358	2,727,358	826,055	517,514	1,343,569	1,812	29,643	12,622	44,078
6	**Expenses:**									
7	Fuel and P&I Expense	758,435	758,435	250,863	173,908	424,771	523	2,577	5,374	8,474
8	Transmission Expense	300,835	300,835	94,589	61,931	156,520	113	434	1,518	2,064
9	Other O & M Expense	485,614	485,614	116,023	66,998	183,021	335	4,747	1,330	6,412
10	Depreciation & Amortization Expense	419,962	419,962	117,936	69,256	187,191	419	11,963	1,424	13,805
11	Other Taxes	197,642	197,642	58,269	36,193	94,462	142	1,150	729	2,021
12	Federal Income Taxes	69,515	69,515	23,182	13,442	36,624	35	1,080	276	1,391
13	Total Expenses	2,232,003	2,232,003	660,861	421,729	1,082,590	1,566	21,950	10,652	34,167
14	Net Operating Income	495,355	495,355	165,194	95,785	260,979	246	7,694	1,970	9,910
15	Other Income Adjustments	9,158	9,158	2,616	1,640	4,256	7	42	34	82
16	Adjusted Net Operating Income	504,513	504,513	167,810	97,425	265,235	253	7,736	2,004	9,992
17	Return on Rate Base @ 6.12%	515,163	515,163	142,692	85,066	227,757	492	11,003	1,631	13,126
18	Income Deficiency (Sufficiency)	10,650	10,650	(25,118)	(12,360)	(37,478)	240	3,267	(373)	3,134
19	Revenue Deficiency (Sufficiency)	14,250	14,250	(33,610)	(16,538)	(50,148)	321	4,372	(500)	4,193
20	Additional Rev Requirement	3,943	3,943	4,043	3,535	7,578	1	(20)	115	96
21	Total Revenue Deficiency (Sufficiency)	18,193	18,193	(29,567)	(13,003)	(42,570)	322	4,352	(385)	4,289
22	Revenue Requirement/Total Cost of Service	2,745,551	2,745,551	796,488	504,511	1,300,999	2,134	33,995	12,237	48,367
23	Less: Revenue Credits	380,299	380,299	121,559	83,695	205,255	270	1,486	2,523	4,279
24	**Proposed Rate Design Revenue**	**2,365,252**	**2,365,252**	**674,929**	**420,815**	**1,095,744**	**1,864**	**32,509**	**9,715**	**44,088**
25	Production: Net Capacity Cost	438,413	438,413	137,846	90,254	228,100	164	632	2,211	3,008
26	Production: Capacity Related Cost Offset	109,110	109,110	37,152	26,445	63,597	105	498	929	1,532
27	Production: Non-Capacity Related Cost	461,777	461,777	153,598	104,879	258,476	270	1,296	3,085	4,651
28	Distribution: Demand Related Cost	1,168,664	1,168,664	310,449	190,159	500,609	1,249	28,759	3,407	33,415
29	Distribution: Customer Related Cost	187,288	187,288	35,884	9,078	44,962	76	1,324	82	1,482
30	Full Service MWH Sales	12,685,410	12,685,410	4,199,402	2,979,606	7,179,008	10,776	54,640	99,352	164,769
31	ROA MWH Sales	-	-	18,702	174,288	192,989	-	-	-	-
32	MWH Sales	12,685,410	12,685,410	4,218,104	3,153,894	7,371,997	10,776	54,640	99,352	164,769
33	Customers	1,680,798	1,680,798	206,948	20,624	227,572	399	4,696	465	5,560

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Rate Base**	182,900	41,019	74,318	721,320	107,767	260,784	584,897	623,210	28,411	7,680	1,601	2,633,908
2	**Revenue**												
3	Total Rate Revenue	76,037	37,506	44,499	345,089	86,707	126,526	248,155	538,702	21,956	4,550	732	1,530,460
4	Total Revenue Credits	17,913	11,414	12,523	87,002	28,385	36,386	62,531	188,786	8,107	1,312	174	454,534
5	Total Revenue	93,950	48,920	57,022	432,091	115,092	162,913	310,687	727,488	30,063	5,862	905	1,984,994
6	**Expenses:**												
7	Fuel and P&I Expense	38,147	24,384	26,847	185,898	59,973	76,848	131,386	401,516	17,427	2,792	388	965,606
8	Transmission Expense	13,734	7,489	8,599	63,872	17,691	23,748	42,211	113,129	5,271	830	129	296,705
9	Other O & M Expense	6,754	2,027	2,586	29,339	5,030	7,977	23,184	31,645	1,413	264	64	110,282
10	Depreciation & Amortization Expense	10,897	3,686	5,038	43,777	9,047	15,324	32,888	56,647	2,580	504	94	180,483
11	Other Taxes	4,762	1,573	2,291	20,466	4,210	7,802	16,361	22,038	889	240	44	80,677
12	Federal Income Taxes	2,419	1,201	1,435	10,920	2,355	3,841	7,957	12,616	306	152	23	43,225
13	Total Expenses	76,714	40,360	46,796	354,274	98,308	135,540	253,988	637,590	27,886	4,781	742	1,676,978
14	Net Operating Income	17,236	8,560	10,227	77,817	16,785	27,373	56,699	89,898	2,178	1,081	163	308,017
15	Other Income Adjustments	211	74	99	919	187	315	707	1,142	52	10	2	3,718
16	Adjusted Net Operating Income	17,447	8,634	10,325	78,736	16,972	27,687	57,406	91,041	2,230	1,091	165	311,735
17	Return on Rate Base @ 6.12%	11,187	2,509	4,545	44,118	6,591	15,950	35,774	38,117	1,738	470	98	161,096
18	Income Deficiency (Sufficiency)	(6,260)	(6,125)	(5,780)	(34,619)	(10,381)	(11,737)	(21,632)	(52,924)	(492)	(622)	(67)	(150,639)
19	Revenue Deficiency (Sufficiency)	(8,376)	(8,196)	(7,734)	(46,323)	(13,891)	(15,705)	(28,946)	(70,816)	(658)	(832)	(90)	(201,567)
20	Additional Rev Requirement	1,158	745	840	5,593	1,717	2,291	3,644	11,672	531	83	11	28,285
21	Total Revenue Deficiency (Sufficiency)	(7,218)	(7,451)	(6,894)	(40,730)	(12,174)	(13,414)	(25,301)	(59,144)	(128)	(749)	(79)	(173,282)
22	Revenue Requirement/Total Cost of Service	86,732	41,469	50,128	391,361	102,918	149,499	285,385	668,344	29,936	5,114	827	1,811,712
23	Less: Revenue Credits	17,913	11,414	12,523	87,002	28,385	36,386	62,531	188,786	8,107	1,312	174	454,534
24	**Proposed Rate Design Revenue**	**68,819**	**30,055**	**37,605**	**304,359**	**74,533**	**113,113**	**222,854**	**479,557**	**21,829**	**3,801**	**653**	**1,357,178**
25	Production: Net Capacity Cost	20,015	10,914	12,532	93,083	25,782	34,609	61,516	164,866	7,682	1,209	188	432,395
26	Production: Capacity Related Cost Offset	6,122	3,959	4,369	30,521	9,617	12,347	21,959	71,515	3,348	537	75	164,369
27	Production: Non-Capacity Related Cost	23,167	14,082	15,757	111,429	34,635	44,768	76,826	226,441	10,081	1,600	240	559,026
28	Distribution: Demand Related Cost	16,585	970	4,498	64,306	4,063	20,462	58,567	15,610	653	421	136	186,270
29	Distribution: Customer Related Cost	2,929	131	450	5,021	436	927	3,987	1,126	65	34	13	15,118
30	Full Service MWH Sales	666,952	464,518	496,642	3,312,240	1,167,540	1,453,040	2,414,780	7,884,000	332,592	53,237	6,737	18,252,279
31	ROA MWH Sales	72,068	-	-	-	1,270,576	1,080,207	953,091	-	-	-	-	3,375,942
32	MWH Sales	739,020	464,518	496,642	3,312,240	2,438,116	2,533,246	3,367,871	7,884,000	332,592	53,237	6,737	21,628,220
33	Customers	1,420	23	80	1,413	36	98	1,077	1	5	7	5	4,166

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Net Plant**						
2	Production	2,251,061	860,405	456,366	7,073	919,413	7,805
3	Transmission	-	-	-	-	-	-
4	Distribution	9,996,812	5,975,938	2,635,847	189,798	1,178,140	17,088
5	General/Common/Intangible	730,148	432,727	168,145	5,537	122,737	1,001
6	Plant Purchased/Sold	0	0	0	0	0	0
7	Total Net Plant	12,978,021	7,269,070	3,260,358	202,408	2,220,291	25,894
8	**Working Capital**						
9	Total Current Assets	3,131,271	1,760,642	721,895	28,236	615,795	4,704
10	Total Current Liabilities	1,019,384	585,514	248,331	15,877	167,943	1,719
11	Total Working Capital	2,111,887	1,175,128	473,563	12,359	447,852	2,985
	Adjustments to Rate Base						
13	Additions to Rate Base	0	0	0	0	0	0
14	Deductions from Rate Base	66,473	21,311	10,102	158	34,235	666
15	Total Adjustments to Rate Base	(66,473)	(21,311)	(10,102)	(158)	(34,235)	(666)
16	**Total Rate Base**	**15,023,435**	**8,422,887**	**3,723,820**	**214,608**	**2,633,908**	**28,213**
17	**Production Expense**						
18	Fuel Expense	551,095	185,515	106,533	2,335	254,355	2,356
19	Purchased & Interchange Power Expense	1,614,933	572,920	318,238	6,139	711,250	6,385
20	Total Fuel and P&I Expense	2,166,028	758,435	424,771	8,474	965,606	8,741
21	Fossil O&M Exp	55,255	20,686	11,093	186	23,089	201
22	Nuclear O&M Exp	0	-	-	-	-	-
23	Hydro O&M Exp	13,209	4,903	2,641	46	5,570	49
23	Other Power Gen O&M Exp	64,631	24,703	13,103	203	26,397	224
24	Other Power Supply O&M Exp	5,268	2,014	1,068	17	2,152	18
25	Total Production O&M Expense	138,363	52,305	27,905	452	57,209	492
26	Total Production (Inc. Fuel and P&I) O&M Expense	2,304,390	810,741	452,676	8,926	1,022,814	9,233
27	**Transmission & Distribution Expense**						
28	Transmission Expense	758,515	300,835	156,520	2,064	296,705	2,391
29	Direct Assign Transmission	0	-	-	-	-	-
30	Distr Oper Exp	115,755	78,108	28,712	3,444	5,452	38
31	Distr Maint Exp	354,948	238,522	91,773	1,452	23,002	198
32	Total Transmission & Distribution O&M Expense	1,229,218	617,465	277,005	6,961	325,159	2,628
33	**Customer Related Expense**						
34	Customer Accounts Exp	59,788	43,397	9,354	245	6,787	6
35	Customer Service Exp	7,158	4,032	1,071	25	2,014	16
36	Other Customer Exp	16,687	13,845	2,664	85	94	0
37	Total Customer O&M Expense	83,634	61,274	13,088	354	8,895	23
38	**Admin & General Expense**	93,510	55,405	21,542	709	15,725	128
39	**Total O&M Expense**	**3,710,752**	**1,544,884**	**764,312**	**16,951**	**1,372,593**	**12,012**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Net Plant**									
2	Production	860,405	860,405	273,701	182,665	456,366	413	1,787	4,872	7,073
3	Transmission	-	-	-	-	-	-	-	-	-
4	Distribution	5,975,938	5,975,938	1,663,937	971,910	2,635,847	6,634	166,451	16,713	189,798
5	General/Common/Intangible	432,727	432,727	105,763	62,383	168,145	291	3,976	1,270	5,537
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0
7	Total Net Plant	7,269,070	7,269,070	2,043,400	1,216,958	3,260,358	7,339	172,214	22,855	202,408
8	**Working Capital**									
9	Total Current Assets	1,760,642	1,760,642	452,025	269,870	721,895	1,284	21,317	5,635	28,236
10	Total Current Liabilities	585,514	585,514	156,204	92,128	248,331	557	13,561	1,760	15,877
11	Total Working Capital	1,175,128	1,175,128	295,821	177,742	473,563	727	7,756	3,876	12,359
	Adjustments to Rate Base									
13	Additions to Rate Base	0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base	21,311	21,311	6,221	3,881	10,102	18	71	69	158
15	Total Adjustments to Rate Base	(21,311)	(21,311)	(6,221)	(3,881)	(10,102)	(18)	(71)	(69)	(158)
16	**Total Rate Base**	**8,422,887**	**8,422,887**	**2,333,000**	**1,390,819**	**3,723,820**	**8,048**	**179,899**	**26,662**	**214,608**
17	**Production Expense**									
18	Fuel Expense	185,515	185,515	62,486	44,048	106,533	147	747	1,441	2,335
19	Purchased & Interchange Power Expense	572,920	572,920	188,377	129,861	318,238	377	1,829	3,933	6,139
20	Total Fuel and P&I Expense	758,435	758,435	250,863	173,908	424,771	523	2,577	5,374	8,474
21	Fossil O&M Exp	20,686	20,686	6,624	4,469	11,093	11	51	125	186
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	4,903	4,903	1,574	1,067	2,641	3	13	30	46
23	Other Power Gen O&M Exp	24,703	24,703	7,858	5,245	13,103	12	51	140	203
24	Other Power Supply O&M Exp	2,014	2,014	641	427	1,068	1	4	11	17
25	Total Production O&M Expense	52,305	52,305	16,698	11,207	27,905	27	119	306	452
26	Total Production (Inc. Fuel and P&I) O&M Expense	810,741	810,741	267,560	185,116	452,676	550	2,696	5,680	8,926
27	**Transmission & Distribution Expense**									
28	Transmission Expense	300,835	300,835	94,589	61,931	156,520	113	434	1,518	2,064
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	78,108	78,108	17,893	10,820	28,712	91	3,157	197	3,444
31	Distr Maint Exp	238,522	238,522	57,693	34,079	91,773	157	698	597	1,452
32	Total Transmission & Distribution O&M Expense	617,465	617,465	170,175	106,830	277,005	361	4,288	2,312	6,961
33	**Customer Related Expense**									
34	Customer Accounts Exp	43,397	43,397	7,101	2,253	9,354	15	180	50	245
35	Customer Service Exp	4,032	4,032	743	328	1,071	2	13	10	25
36	Other Customer Exp	13,845	13,845	2,346	318	2,664	6	71	7	85
37	Total Customer O&M Expense	61,274	61,274	10,189	2,899	13,088	22	265	67	354
38	**Admin & General Expense**	55,405	55,405	13,550	7,992	21,542	37	509	163	709
39	**Total O&M Expense**	**1,544,884**	**1,544,884**	**461,475**	**302,838**	**764,312**	**971**	**7,758**	**8,222**	**16,951**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate - GPTU Vlt 1	(d) Rate - GPTU Vlt 2	(e) Rate - GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Net Plant**												
2	Production	40,261	23,270	26,284	190,326	54,472	72,548	128,950	363,845	16,459	2,613	386	919,413
3	Transmission	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	112,859	6,742	34,195	395,406	29,949	149,298	354,556	86,126	4,414	3,668	928	1,178,140
5	General/Common/Intangible	7,072	2,429	3,058	31,135	5,980	9,300	23,971	37,721	1,696	310	67	122,737
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Net Plant	160,191	32,440	63,537	616,866	90,401	231,146	507,476	487,692	22,570	6,591	1,380	2,220,291
8	**Working Capital**												
9	Total Current Assets	34,575	12,674	16,247	150,902	30,949	49,478	115,012	195,324	8,652	1,658	324	615,795
10	Total Current Liabilities	11,580	2,705	4,610	45,689	7,170	15,915	36,903	40,929	1,866	474	101	167,943
11	Total Working Capital	22,995	9,969	11,637	105,213	23,779	33,563	78,109	154,395	6,786	1,184	222	447,852
	Adjustments to Rate Base												
13	Additions to Rate Base	0	0	0	0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base	286	1,391	856	760	6,412	3,925	689	18,877	944	94	2	34,235
15	Total Adjustments to Rate Base	(286)	(1,391)	(856)	(760)	(6,412)	(3,925)	(689)	(18,877)	(944)	(94)	(2)	(34,235)
16	**Total Rate Base**	**182,900**	**41,019**	**74,318**	**721,320**	**107,767**	**260,784**	**584,897**	**623,210**	**28,411**	**7,680**	**1,601**	**2,633,908**
17	**Production Expense**												
18	Fuel Expense	9,642	6,418	6,997	47,593	16,069	20,307	34,212	107,671	4,604	740	101	254,355
19	Purchased & Interchange Power Expense	28,505	17,967	19,849	138,304	43,903	56,541	97,174	293,845	12,823	2,052	288	711,250
20	Total Fuel and P&I Expense	38,147	24,384	26,847	185,898	59,973	76,848	131,386	401,516	17,427	2,792	388	965,606
21	Fossil O&M Exp	982	585	655	4,682	1,363	1,809	3,215	9,308	415	66	9	23,089
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	234	141	158	1,120	329	435	773	2,262	100	16	2	5,570
23	Other Power Gen O&M Exp	1,156	668	755	5,464	1,564	2,083	3,702	10,446	473	75	11	26,397
24	Other Power Supply O&M Exp	94	54	62	445	127	170	302	852	39	6	1	2,152
25	Total Production O&M Expense	2,466	1,449	1,629	11,712	3,383	4,496	7,992	22,867	1,026	163	24	57,209
26	Total Production (Inc. Fuel and P&I) O&M Expense	40,613	25,834	28,476	197,610	63,356	81,344	139,378	424,383	18,453	2,955	412	1,022,814
27	**Transmission & Distribution Expense**												
28	Transmission Expense	13,734	7,489	8,599	63,872	17,691	23,748	42,211	113,129	5,271	830	129	296,705
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	489	6	21	2,377	41	172	2,193	140	6	3	5	5,452
31	Distr Maint Exp	2,453	51	300	9,410	226	1,322	8,502	651	33	32	22	23,002
32	Total Transmission & Distribution O&M Expense	16,676	7,546	8,920	75,659	17,958	25,242	52,906	113,920	5,310	866	157	325,159
33	**Customer Related Expense**												
34	Customer Accounts Exp	347	166	196	1,513	386	556	1,090	2,412	99	20	3	6,787
35	Customer Service Exp	71	43	46	310	226	235	314	732	31	5	1	2,014
36	Other Customer Exp	23	1	2	29	2	4	22	10	1	0	0	94
37	Total Customer O&M Expense	441	210	244	1,852	614	795	1,426	3,154	130	25	4	8,895
38	**Admin & General Expense**	906	311	392	3,989	766	1,192	3,071	4,833	217	40	9	15,725
39	**Total O&M Expense**	**58,636**	**33,900**	**38,032**	**279,110**	**82,694**	**108,573**	**196,782**	**546,290**	**24,111**	**3,885**	**581**	**1,372,593**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
	Input Allocation Schedules						
1	Energy @ Generation	100.000	33.906	19.188	0.440	46.025	0.441
2	Energy On-Peak @ Generation	100.000	32.760	20.818	0.340	45.730	0.351
3	Energy Off-Peak @ Generation	100.000	34.750	17.300	0.540	46.880	0.530
4	Energy On-Peak @ Generation Summer	100.000	34.135	21.405	0.284	43.813	0.363
5	Energy Off-Peak @ Generation Summer	100.000	35.421	17.712	0.487	45.800	0.579
6	Energy On-Peak @ Generation Non-Summer	100.000	31.974	20.483	0.372	46.826	0.344
7	Energy Off-Peak @ Generation Non-Summer	100.000	34.385	17.075	0.569	47.467	0.504
8	Energy Critical On-Peak @ Gen	100.000	36.621	21.818	0.218	41.083	0.259
9	Energy Summer Mid-Peak @ Gen	100.000	33.229	21.254	0.308	44.809	0.401
10	12CP Dmd @ Generation	100.000	39.661	20.635	0.272	39.117	0.315
11	4CP Dmd @ Generation	100.000	39.661	20.635	0.272	39.117	0.315
12	Class Peak @ Voltage 1	100.000	41.935	19.878	0.312	37.315	0.561
13	Production Revenue	100.000	37.294	20.190	0.336	42.222	(0.042)
14	Distribution Revenue	100.000	61.655	26.328	1.586	10.271	0.160
15	Total Rate Revenue	100.000	45.705	22.309	0.768	31.190	0.028
16	Billed Sales	100.000	30.186	17.542	0.392	51.467	0.412
17	Number Of Customers	100.000	87.628	11.864	0.290	0.217	0.001
18	Weighted Customer	100.000	60.166	28.619	0.054	11.124	0.038
		-					
	*Calculated Allocation Schedules						
19	4CP 75/0/25	100.000	38.222	20.273	0.314	40.844	0.347
20	Class Peak @ Voltage 2	100.000	50.207	23.799	0.373	24.949	0.672
21	Class Peak Voltage 1 Only	100.000	-	-	-	98.503	1.497
22	Class Peak Voltage 2 Only	100.000	-	-	-	95.387	4.613
23	Class Peak @ Voltage 1 excluding Voltage 2	100.000	44.342	21.019	0.329	33.982	0.329
24	Class Peak @ Voltage 3	100.000	53.875	25.538	0.400	20.109	0.077
25	Class Peak @ Voltage 4	100.000	67.502	31.997	0.501	-	-
26	Class Peak for Streetlighting	100.000	-	-	100.000	-	-
27	Class Peak @ Single Phase	100.000	67.502	31.997	0.501	-	-
28	Billed Sales - Primary	100.000	45.911	26.681	0.596	26.744	0.067
29	Customers - Residential	100.000	100.000	-	-	-	-
30	Customers - Commercial Secondary	100.000	-	100.000	-	-	-
31	Customers - Non-Primary	100.000	88.057	11.922	0.021	-	-
32	Customers - Non-Lighting	100.000	87.883	11.899	-	0.218	0.001
33	Customers - Commercial & Primary	100.000	-	98.196	-	1.798	0.006
34	Customer Count (CCC)	100.000	93.559	6.441	-	-	-
35	Customer Count (BCC)	100.000	-	91.990	4.572	3.426	0.012
36	PIS - HVD (Voltage 1)	100.000	50.168	23.781	0.373	25.071	0.607
37	PIS - HVD (Voltage 2)	100.000	50.117	23.756	0.372	25.218	0.537
38	PIS - HVD (Voltage 1) Substations	100.000	50.207	23.799	0.373	24.949	0.672
39	PIS - HVD (Voltage 2) Substations	100.000	41.526	19.684	0.309	37.365	1.117
40	PIS - OH LVD System	100.000	63.654	30.173	0.473	5.678	0.022
41	PIS - LVD Distribution	100.000	63.001	26.146	2.447	8.323	0.082
42	PIS- OH (LVD & HVD) Lines & Services	100.000	66.214	25.689	0.389	7.625	0.083
43	PIS- UG LVD Distribution	100.000	63.298	30.005	0.470	6.184	0.043
44	PIS- Total Distribution	100.000	61.233	25.819	2.162	10.638	0.148

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
	Input Allocation Schedules									
1	Energy @ Generation	33.906	33.906	11.224	7.964	19.188	0.029	0.146	0.266	0.440
2	Energy On-Peak @ Generation	32.760	32.760	12.407	8.412	20.818	0.015	0.078	0.248	0.340
3	Energy Off-Peak @ Generation	34.750	34.750	9.882	7.418	17.300	0.043	0.215	0.282	0.540
4	Energy On-Peak @ Generation Summer	34.135	34.135	12.788	8.616	21.405	0.007	0.048	0.229	0.284
5	Energy Off-Peak @ Generation Summer	35.421	35.421	10.126	7.587	17.712	0.036	0.187	0.264	0.487
6	Energy On-Peak @ Generation Non-Summer	31.974	31.974	12.189	8.295	20.483	0.019	0.095	0.258	0.372
7	Energy Off-Peak @ Generation Non-Summer	34.385	34.385	9.749	7.326	17.075	0.047	0.230	0.291	0.569
8	Energy Critical On-Peak @ Gen	36.621	36.621	13.089	8.729	21.818	0.001	0.003	0.214	0.218
9	Energy Summer Mid-Peak @ Gen	33.229	33.229	12.679	8.575	21.254	0.009	0.065	0.234	0.308
10	12CP Dmd @ Generation	39.661	39.661	12.470	8.165	20.635	0.015	0.057	0.200	0.272
11	4CP Dmd @ Generation	39.661	39.661	12.470	8.165	20.635	0.015	0.057	0.200	0.272
12	Class Peak @ Voltage 1	41.935	41.935	12.242	7.636	19.878	0.035	0.141	0.136	0.312
13	Production Revenue	37.294	37.294	12.000	8.190	20.190	0.018	0.089	0.229	0.336
14	Distribution Revenue	61.655	61.655	17.136	9.192	26.328	0.053	1.379	0.154	1.586
15	Total Rate Revenue	45.705	45.705	13.773	8.536	22.309	0.030	0.535	0.203	0.768
16	Billed Sales	30.186	30.186	10.037	7.505	17.542	0.026	0.130	0.236	0.392
17	Number Of Customers	87.628	87.628	10.789	1.075	11.864	0.021	0.245	0.024	0.290
18	Weighted Customer	60.166	60.166	23.310	5.309	28.619	0.054	-	-	0.054
	*Calculated Allocation Schedules									
19	4CP 75/0/25	38.222	38.222	12.159	8.115	20.273	0.018	0.079	0.216	0.314
20	Class Peak @ Voltage 2	50.207	50.207	14.657	9.142	23.799	0.042	0.168	0.163	0.373
21	Class Peak Voltage 1 Only	-	-	-	-	-	-	-	-	-
22	Class Peak Voltage 2 Only	-	-	-	-	-	-	-	-	-
23	Class Peak @ Voltage 1 excluding Voltage 2	44.342	44.342	12.944	8.074	21.019	0.037	0.149	0.144	0.329
24	Class Peak @ Voltage 3	53.875	53.875	15.728	9.810	25.538	0.045	0.181	0.175	0.400
25	Class Peak @ Voltage 4	67.502	67.502	19.705	12.291	31.997	0.056	0.226	0.219	0.501
26	Class Peak for Streetlighting	-	-	-	-	-	19.934	80.066	-	100.000
27	Class Peak @ Single Phase	67.502	67.502	19.705	12.291	31.997	0.056	0.226	0.219	0.501
28	Billed Sales - Primary	45.911	45.911	15.266	11.415	26.681	0.039	0.198	0.360	0.596
29	Customers - Residential	100.000	100.000	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	90.937	9.063	100.000	-	-	-	-
31	Customers - Non-Primary	88.057	88.057	10.842	1.080	11.922	0.021	-	-	0.021
32	Customers - Non-Lighting	87.883	87.883	10.821	1.078	11.899	-	-	-	-
33	Customers - Commercial & Primary	-	-	89.297	8.899	98.196	-	-	-	-
34	Customer Count (CCC)	93.559	93.559	6.388	0.054	6.441	-	-	-	-
35	Customer Count (BCC)	-	-	75.820	16.170	91.990	0.328	3.862	0.382	4.572
36	PIS - HVD (Voltage 1)	50.168	50.168	14.645	9.135	23.781	0.042	0.168	0.163	0.373
37	PIS - HVD (Voltage 2)	50.117	50.117	14.630	9.126	23.756	0.042	0.168	0.162	0.372
38	PIS - HVD (Voltage 1) Substations	50.207	50.207	14.657	9.142	23.799	0.042	0.168	0.163	0.373
39	PIS - HVD (Voltage 2) Substations	41.526	41.526	12.122	7.562	19.684	0.035	0.139	0.135	0.309
40	PIS - OH LVD System	63.654	63.654	18.582	11.591	30.173	0.053	0.214	0.206	0.473
41	PIS - LVD Distribution	63.001	63.001	16.653	9.493	26.146	0.073	2.212	0.162	2.447
42	PIS- OH (LVD & HVD) Lines & Services	66.214	66.214	16.075	9.615	25.689	0.044	0.176	0.170	0.389
43	PIS- UG LVD Distribution	63.298	63.298	18.478	11.526	30.005	0.053	0.212	0.205	0.470
44	PIS- Total Distribution	61.233	61.233	16.375	9.443	25.819	0.069	1.931	0.162	2.162

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
	Input Allocation Schedules												
1	Energy @ Generation	1.722	1.173	1.269	8.558	2.682	3.499	6.219	19.909	0.840	0.136	0.017	46.025
2	Energy On-Peak @ Generation	2.000	1.160	1.329	9.499	2.836	3.657	6.202	18.040	0.851	0.130	0.025	45.730
3	Energy Off-Peak @ Generation	1.416	1.174	1.194	7.494	3.035	3.736	6.213	21.648	0.819	0.141	0.009	46.880
4	Energy On-Peak @ Generation Summer	2.009	1.118	1.278	9.422	2.701	3.496	6.271	16.597	0.780	0.118	0.023	43.813
5	Energy Off-Peak @ Generation Summer	1.437	1.147	1.185	7.606	2.971	3.626	6.397	20.508	0.781	0.132	0.009	45.800
6	Energy On-Peak @ Generation Non-Summer	1.994	1.184	1.358	9.542	2.913	3.749	6.163	18.866	0.892	0.137	0.027	46.826
7	Energy Off-Peak @ Generation Non-Summer	1.405	1.189	1.199	7.432	3.070	3.796	6.113	22.268	0.840	0.146	0.009	47.467
8	Energy Critical On-Peak @ Gen	1.888	1.020	1.178	8.935	2.415	3.260	6.013	15.530	0.733	0.098	0.013	41.083
9	Energy Summer Mid-Peak @ Gen	2.053	1.154	1.315	9.600	2.805	3.582	6.365	16.986	0.797	0.125	0.027	44.809
10	12CP Dmd @ Generation	1.811	0.987	1.134	8.421	2.332	3.131	5.565	14.915	0.695	0.109	0.017	39.117
11	4CP Dmd @ Generation	1.811	0.987	1.134	8.421	2.332	3.131	5.565	14.915	0.695	0.109	0.017	39.117
12	Class Peak @ Voltage 1	1.911	0.829	0.894	7.253	3.822	4.100	6.575	11.253	0.563	0.099	0.017	37.315
13	Production Revenue	1.755	1.131	1.235	8.407	2.586	3.394	5.839	17.078	0.676	0.108	0.014	42.222
14	Distribution Revenue	1.063	0.075	0.271	4.104	0.268	1.010	3.356	-	0.043	0.064	0.016	10.271
15	Total Rate Revenue	1.516	0.767	0.902	6.921	1.786	2.571	4.982	11.181	0.457	0.093	0.015	31.190
16	Billed Sales	1.759	1.105	1.182	7.882	5.802	6.028	8.014	18.761	0.791	0.127	0.016	51.467
17	Number Of Customers	0.074	0.001	0.004	0.074	0.002	0.005	0.056	0.000	0.000	0.000	0.000	0.217
18	Weighted Customer	3.005	0.071	0.361	4.140	0.125	0.303	3.065	0.004	0.019	0.021	0.011	11.124
		-	-	-	-	-	-	-	-	-	-	-	-
	*Calculated Allocation Schedules	-	-	-	-	-	-	-	-	-	-	-	-
19	4CP 75/0/25	1.789	1.034	1.168	8.455	2.420	3.223	5.728	16.163	0.731	0.116	0.017	40.844
20	Class Peak @ Voltage 2	2.277	-	1.070	8.684	-	4.908	7.871	-	-	0.118	0.020	24.949
21	Class Peak Voltage 1 Only	0.053	4.956	-	-	22.853	-	-	67.276	3.366	-	-	98.503
22	Class Peak Voltage 2 Only	1.574	-	16.464	-	-	75.532	-	-	-	1.817	-	95.387
23	Class Peak @ Voltage 1 excluding Voltage 2	1.930	0.876	-	7.670	4.042	-	6.952	11.899	0.595	-	0.018	33.982
24	Class Peak @ Voltage 3	2.323	-	-	9.318	-	-	8.447	-	-	-	0.022	20.109
25	Class Peak @ Voltage 4	-	-	-	-	-	-	-	-	-	-	-	-
26	Class Peak for Streetlighting	-	-	-	-	-	-	-	-	-	-	-	-
27	Class Peak @ Single Phase	-	-	-	-	-	-	-	-	-	-	-	-
28	Billed Sales - Primary	2.543	-	-	11.988	-	-	12.189	-	-	-	0.024	26.744
29	Customers - Residential	-	-	-	-	-	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	-	-	-	-	-	-	-	-	-	-
31	Customers - Non-Primary	-	-	-	-	-	-	-	-	-	-	-	-
32	Customers - Non-Lighting	0.074	0.001	0.004	0.074	0.002	0.005	0.056	0.000	0.000	0.000	0.000	0.218
33	Customers - Commercial & Primary	0.613	0.010	0.035	0.610	0.016	0.042	0.465	0.000	0.002	0.003	0.002	1.798
34	Customer Count (CCC)	-	-	-	-	-	-	-	-	-	-	-	-
35	Customer Count (BCC)	1.168	0.019	0.066	1.162	0.030	0.080	0.886	0.001	0.004	0.006	0.004	3.426
36	PIS - HVD (Voltage 1)	2.263	0.042	0.949	8.677	0.195	4.352	7.865	0.574	0.029	0.105	0.020	25.071
37	PIS - HVD (Voltage 2)	1.945	-	1.687	7.157	-	7.739	6.487	-	-	0.186	0.017	25.218
38	PIS - HVD (Voltage 1) Substations	2.277	-	1.070	8.684	-	4.908	7.871	-	-	0.118	0.020	24.949
39	PIS - HVD (Voltage 2) Substations	2.151	-	3.774	7.182	-	17.314	6.510	-	-	0.417	0.017	37.365
40	PIS - OH LVD System	0.656	-	-	2.631	-	-	2.385	-	-	-	0.006	5.678
41	PIS - LVD Distribution	0.889	0.065	0.116	2.990	0.285	0.441	2.663	0.814	0.042	0.012	0.007	8.323
42	PIS- OH (LVD & HVD) Lines & Services	0.774	0.014	0.129	3.054	0.067	0.592	2.768	0.196	0.010	0.014	0.007	7.625
43	PIS- UG LVD Distribution	0.556	0.067	0.008	2.223	0.311	0.037	2.015	0.915	0.046	0.001	0.005	6.184
44	PIS- Total Distribution	1.049	0.058	0.297	3.635	0.255	1.284	3.254	0.729	0.038	0.032	0.009	10.638

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	*Calculated Allocation Schedules						
2	PIS- Distribution Services	100.000	94.121	5.879	-	-	-
3	PIS- Streetlighting Equipment	100.000	-	-	100.000	-	-
4	PIS- Line Equipment	100.000	66.184	31.372	0.492	1.944	0.007
5	PIS- Meters	100.000	60.166	28.619	0.054	11.124	0.038
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000
7	Total PIS	100.000	56.369	24.474	1.679	17.290	0.188
8	Distribution Depreciation	100.000	64.795	24.617	2.708	7.788	0.092
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	100.000	34.944	16.564	0.260	47.656	0.576
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	100.000	50.502	23.939	0.375	24.694	0.491
11	PIS- LVD OH Lines & Services	100.000	68.843	26.036	0.392	4.711	0.018
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	100.000	-	-	-	98.503	1.497
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	100.000	52.165	24.727	0.388	22.394	0.327
14	CWIP	100.000	53.083	24.669	0.477	21.553	0.218
15	Rate Base- Total	100.000	56.065	24.787	1.428	17.532	0.188
16	Dist Op Expense (LVD) excl Sup & Eng	100.000	67.911	24.847	3.035	4.185	0.022
17	Dist Maint Expense (LVD) excl Sup & Eng	100.000	68.695	26.092	0.413	4.781	0.018
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.047	21.353	0.335	32.739	0.525
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.522	21.578	0.338	32.038	0.523
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.626	23.524	0.369	25.955	0.526
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.354	23.395	0.367	26.347	0.537
22	Total HVD Distribution O&M Expense	100.000	48.212	22.853	0.358	28.044	0.532
23	Total Distribution O&M Expense (excl. HVD)	100.000	68.541	25.773	1.077	4.590	0.018
24	Total Customer Accounts Expense (excl. Supv)	100.000	72.584	15.645	0.410	11.351	0.010
25	Total Customer Accounts & Service Expense	100.000	70.846	15.571	0.403	13.147	0.033
26	Pre Tax NOI	100.000	45.910	24.188	0.918	28.547	0.436
27	Depreciation & Amortization Expense	100.000	52.291	23.308	1.719	22.473	0.209
28	Non PSCR O&M Expense	100.000	61.766	23.279	0.816	14.027	0.112
29	Distribution Depreciation Expense	100.000	61.447	25.637	2.973	9.819	0.123
30	Gen/Comm/Int Depreciation Expense	100.000	59.251	23.037	0.759	16.816	0.137
31	Production Labor	100.000	38.222	20.273	0.314	40.844	0.347
32	Total Labor	100.000	59.251	23.037	0.759	16.816	0.137
33	50% O&M, 50% Net Plant	100.000	52.814	24.116	1.314	21.529	0.227
34	50/50 PIS & Labor	100.000	57.810	23.756	1.219	17.053	0.163

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	*Calculated Allocation Schedules									
2	PIS- Distribution Services	94.121	94.121	5.347	0.533	5.879	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	1.423	98.577	-	100.000
4	PIS- Line Equipment	66.184	66.184	19.321	12.052	31.372	0.055	0.222	0.214	0.492
5	PIS- Meters	60.166	60.166	23.310	5.309	28.619	0.054	-	-	0.054
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Total PIS	56.369	56.369	15.370	9.104	24.474	0.056	1.448	0.174	1.679
8	Distribution Depreciation	64.795	64.795	15.775	8.842	24.617	0.074	2.484	0.150	2.708
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	34.944	34.944	10.201	6.363	16.564	0.029	0.117	0.113	0.260
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	50.502	50.502	14.743	9.196	23.939	0.042	0.169	0.164	0.375
11	PIS- LVD OH Lines & Services	68.843	68.843	16.328	9.708	26.036	0.044	0.177	0.171	0.392
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	-	-	-	-	-	-	-	-	-
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	52.165	52.165	15.228	9.499	24.727	0.044	0.175	0.169	0.388
14	CWIP	53.083	53.083	15.161	9.508	24.669	0.038	0.242	0.196	0.477
15	Rate Base- Total	56.065	56.065	15.529	9.258	24.787	0.054	1.197	0.177	1.428
16	Dist Op Expense (LVD) excl Sup & Eng	67.911	67.911	15.488	9.359	24.847	0.080	2.785	0.170	3.035
17	Dist Maint Expense (LVD) excl Sup & Eng	68.695	68.695	16.426	9.666	26.092	0.045	0.199	0.169	0.413
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	45.047	45.047	13.151	8.203	21.353	0.038	0.151	0.146	0.335
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	45.522	45.522	13.289	8.289	21.578	0.038	0.153	0.147	0.338
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	49.626	49.626	14.487	9.037	23.524	0.041	0.166	0.161	0.369
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	49.354	49.354	14.408	8.987	23.395	0.041	0.166	0.160	0.367
22	Total HVD Distribution O&M Expense	48.212	48.212	14.074	8.779	22.853	0.040	0.162	0.156	0.358
23	Total Distribution O&M Expense (excl. HVD)	68.541	68.541	16.185	9.589	25.773	0.053	0.854	0.170	1.077
24	Total Customer Accounts Expense (excl. Supv)	72.584	72.584	11.876	3.769	15.645	0.024	0.301	0.084	0.410
25	Total Customer Accounts & Service Expense	70.846	70.846	11.716	3.855	15.571	0.024	0.289	0.090	0.403
26	Pre Tax NOI	45.910	45.910	15.310	8.878	24.188	0.023	0.713	0.183	0.918
27	Depreciation & Amortization Expense	52.291	52.291	14.685	8.623	23.308	0.052	1.490	0.177	1.719
28	Non PSCR O&M Expense	61.766	61.766	14.757	8.522	23.279	0.043	0.604	0.169	0.816
29	Distribution Depreciation Expense	61.447	61.447	16.618	9.019	25.637	0.080	2.745	0.148	2.973
30	Gen/Comm/Int Depreciation Expense	59.251	59.251	14.490	8.547	23.037	0.040	0.545	0.174	0.759
31	Production Labor	38.222	38.222	12.159	8.115	20.273	0.018	0.079	0.216	0.314
32	Total Labor	59.251	59.251	14.490	8.547	23.037	0.040	0.545	0.174	0.759
33	50% O&M, 50% Net Plant	52.814	52.814	15.009	9.107	24.116	0.050	1.078	0.186	1.314
34	50/50 PIS & Labor	57.810	57.810	14.930	8.825	23.756	0.048	0.997	0.174	1.219

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
12CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) - Rate GPTU Vlt 1	(d) - Rate GPTU Vlt 2	(e) - Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	*Calculated Allocation Schedules												
2	PIS- Distribution Services	-	-	-	-	-	-	-	-	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	-	-	-	-	-	-	-
4	PIS- Line Equipment	0.225	-	-	0.901	-	-	0.817	-	-	-	0.002	1.944
5	PIS- Meters	3.005	0.071	0.361	4.140	0.125	0.303	3.065	0.004	0.019	0.021	0.011	11.124
6	PIS - General	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Total PIS	1.195	0.278	0.485	4.670	0.741	1.681	3.764	4.224	0.194	0.050	0.010	17.290
8	Distribution Depreciation	0.842	0.035	0.181	2.838	0.148	0.751	2.531	0.413	0.022	0.019	0.007	7.788
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	1.527	1.741	-	6.044	8.030	-	5.479	23.639	1.183	-	0.014	47.656
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	2.278	-	1.008	8.735	-	4.623	7.918	-	-	0.111	0.020	24.694
11	PIS- LVD OH Lines & Services	0.544	-	-	2.183	-	-	1.979	-	-	-	0.005	4.711
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	0.053	4.956	-	-	22.853	-	-	67.276	3.366	-	-	98.503
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	2.301	-	0.504	9.023	-	2.311	8.178	-	-	0.056	0.021	22.394
14	CWIP	1.221	0.428	0.573	5.329	1.086	1.823	4.099	6.622	0.301	0.058	0.011	21.553
15	Rate Base- Total	1.217	0.273	0.495	4.801	0.717	1.736	3.893	4.148	0.189	0.051	0.011	17.532
16	Dist Op Expense (LVD) excl Sup & Eng	0.382	0.001	(0.005)	1.910	0.016	0.043	1.765	0.065	0.002	0.000	0.004	4.185
17	Dist Maint Expense (LVD) excl Sup & Eng	0.573	0.001	0.004	2.203	0.002	0.004	1.989	0.000	0.000	0.000	0.005	4.781
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	1.998	0.666	0.463	7.792	3.071	2.124	7.063	9.041	0.452	0.051	0.018	32.739
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	2.020	0.615	0.485	7.874	2.838	2.224	7.137	8.355	0.418	0.054	0.018	32.038
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	2.265	-	1.282	8.584	-	5.882	7.780	-	-	0.142	0.020	25.955
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	2.261	-	1.367	8.537	-	6.273	7.738	-	-	0.151	0.020	26.347
22	Total HVD Distribution O&M Expense	2.189	0.186	1.097	8.339	0.856	5.033	7.559	2.519	0.126	0.121	0.019	28.044
23	Total Distribution O&M Expense (excl. HVD)	0.521	0.001	0.000	2.119	0.004	0.006	1.923	0.012	0.001	0.000	0.005	4.590
24	Total Customer Accounts Expense (excl. Supv)	0.580	0.277	0.327	2.530	0.645	0.930	1.823	4.035	0.165	0.034	0.005	11.351
25	Total Customer Accounts & Service Expense	0.624	0.312	0.361	2.722	0.914	1.182	2.097	4.696	0.194	0.037	0.006	13.147
26	Pre Tax NOI	1.597	0.793	0.948	7.212	1.556	2.537	5.255	8.332	0.202	0.100	0.015	28.547
27	Depreciation & Amortization Expense	1.357	0.459	0.627	5.451	1.127	1.908	4.095	7.053	0.321	0.063	0.012	22.473
28	Non PSCR O&M Expense	0.859	0.258	0.329	3.732	0.640	1.015	2.949	4.025	0.180	0.034	0.008	14.027
29	Distribution Depreciation Expense	1.112	0.052	0.263	3.434	0.217	1.048	3.031	0.595	0.032	0.027	0.008	9.819
30	Gen/Comm/Int Depreciation Expense	0.969	0.333	0.419	4.266	0.819	1.274	3.284	5.168	0.232	0.042	0.009	16.816
31	Production Labor	1.789	1.034	1.168	8.455	2.420	3.223	5.728	16.163	0.731	0.116	0.017	40.844
32	Total Labor	0.969	0.333	0.419	4.266	0.819	1.274	3.284	5.168	0.232	0.042	0.009	16.816
33	50% O&M, 50% Net Plant	1.311	0.398	0.609	5.369	1.037	2.036	4.220	6.196	0.280	0.063	0.012	21.529
34	50/50 PIS & Labor	1.082	0.306	0.452	4.468	0.780	1.478	3.524	4.696	0.213	0.046	0.010	17.053

*Calculated allocation schedules may vary between product

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Rate Base**	15,023,435	8,769,803	3,859,277	214,106	2,147,976	32,273
2	**Revenue**						
3	Total Rate Revenue	4,459,875	2,322,632	1,124,490	39,481	971,793	1,478
4	Total Revenue Credits	586,639	253,596	135,184	3,086	177,844	16,929
5	Total Revenue	5,046,515	2,576,229	1,259,674	42,568	1,149,637	18,407
6	**Expenses:**						
7	Fuel and P&I Expense	1,689,799	731,937	406,001	8,054	535,347	8,459
8	Transmission Expense	635,028	296,007	154,008	2,031	180,630	2,353
9	Other O & M Expense	786,210	504,019	190,444	6,408	84,347	992
10	Depreciation & Amortization Expense	803,119	454,220	200,272	13,711	133,012	1,903
11	Other Taxes	350,149	196,602	93,169	1,930	57,502	946
12	Federal Income Taxes	57,300	28,821	15,807	764	11,633	275
13	Total Expenses	4,321,605	2,211,606	1,059,701	32,898	1,002,471	14,928
14	Net Operating Income	724,910	364,623	199,973	9,670	147,166	3,479
15	Other Income Adjustments	17,252	9,865	4,529	81	2,737	41
16	Adjusted Net Operating Income	742,162	374,487	204,502	9,750	149,903	3,520
17	Return on Rate Base @ 6.12%	918,867	536,381	236,042	13,095	131,375	1,974
18	Income Deficiency (Sufficiency)	176,705	161,893	31,540	3,345	(18,528)	(1,546)
19	Revenue Deficiency (Sufficiency)	236,445	216,626	42,203	4,476	(24,792)	(2,068)
20	Additional Rev Requirement	40,158	11,459	10,394	67	17,957	281
21	Total Revenue Deficiency (Sufficiency)	276,603	228,085	52,597	4,543	(6,835)	(1,787)
22	Revenue Requirement/Total Cost of Service	5,323,118	2,804,314	1,312,271	47,110	1,142,802	16,620
23	Less: Revenue Credits	586,639	253,596	135,184	3,086	177,844	16,929
24	**Proposed Rate Design Revenue**	**4,736,478**	**2,550,718**	**1,177,087**	**44,024**	**964,958**	**(309)**
25	Production: Net Capacity Cost	867,850	438,573	210,425	1,683	214,359	2,809
26	Production: Capacity Related Cost Offset	339,952	147,036	80,708	1,645	109,054	1,509
27	Production: Non-Capacity Related Cost	1,425,348	625,995	349,525	6,389	450,790	(7,351)
28	Distribution: Demand Related Cost	1,854,383	1,151,465	491,265	32,819	176,219	2,615
29	Distribution: Customer Related Cost	248,945	187,649	45,164	1,487	14,537	109
30	Full Service MWH Sales	30,570,766	12,685,410	7,179,008	164,769	10,368,279	173,301
31	ROA MWH Sales	3,568,931	-	192,989	-	3,375,942	-
32	MWH Sales	34,139,697	12,685,410	7,371,997	164,769	13,744,220	173,301
33	Customers	1,918,108	1,680,798	227,572	5,560	4,165	14

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Rate Base**	8,769,803	8,769,803	2,418,244	1,441,033	3,859,277	7,799	179,149	27,159	214,106
2	**Revenue**									
3	Total Rate Revenue	2,322,632	2,322,632	696,410	428,081	1,124,490	1,521	28,052	9,908	39,481
4	Total Revenue Credits	253,596	253,596	79,746	55,438	135,184	199	1,163	1,724	3,086
5	Total Revenue	2,576,229	2,576,229	776,156	483,518	1,259,674	1,720	29,215	11,632	42,568
6	**Expenses:**									
7	Fuel and P&I Expense	731,937	731,937	239,676	166,325	406,001	479	2,428	5,146	8,054
8	Transmission Expense	296,007	296,007	93,071	60,937	154,008	111	427	1,493	2,031
9	Other O & M Expense	504,019	504,019	120,661	69,783	190,444	324	4,719	1,365	6,408
10	Depreciation & Amortization Expense	454,220	454,220	126,194	74,078	200,272	390	11,858	1,463	13,711
11	Other Taxes	196,602	196,602	57,535	35,634	93,169	135	1,095	700	1,930
12	Federal Income Taxes	28,821	28,821	10,184	5,623	15,807	21	636	107	764
13	Total Expenses	2,211,606	2,211,606	647,320	412,381	1,059,701	1,460	21,163	10,275	32,898
14	Net Operating Income	364,623	364,623	128,836	71,137	199,973	260	8,052	1,357	9,670
15	Other Income Adjustments	9,865	9,865	2,788	1,741	4,529	6	40	35	81
16	Adjusted Net Operating Income	374,487	374,487	131,623	72,879	204,502	266	8,092	1,392	9,750
17	Return on Rate Base @ 6.12%	536,381	536,381	147,905	88,137	236,042	477	10,957	1,661	13,095
18	Income Deficiency (Sufficiency)	161,893	161,893	16,282	15,258	31,540	211	2,865	269	3,345
19	Revenue Deficiency (Sufficiency)	216,626	216,626	21,786	20,417	42,203	282	3,834	360	4,476
20	Additional Rev Requirement	11,459	11,459	5,826	4,569	10,394	(6)	(49)	122	67
21	Total Revenue Deficiency (Sufficiency)	228,085	228,085	27,612	24,985	52,597	276	3,784	482	4,543
22	Revenue Requirement/Total Cost of Service	2,804,314	2,804,314	803,768	508,504	1,312,271	1,996	33,000	12,115	47,110
23	Less: Revenue Credits	253,596	253,596	79,746	55,438	135,184	199	1,163	1,724	3,086
24	**Proposed Rate Design Revenue**	**2,550,718**	**2,550,718**	**724,021**	**453,066**	**1,177,087**	**1,797**	**31,836**	**10,390**	**44,024**
25	Production: Net Capacity Cost	438,573	438,573	128,665	81,760	210,425	7	-	1,676	1,683
26	Production: Capacity Related Cost Offset	147,036	147,036	47,703	33,006	80,708	99	481	1,066	1,645
27	Production: Non-Capacity Related Cost	625,995	625,995	207,574	141,951	349,525	379	1,814	4,197	6,389
28	Distribution: Demand Related Cost	1,151,465	1,151,465	304,078	187,187	491,265	1,236	28,216	3,367	32,819
29	Distribution: Customer Related Cost	187,649	187,649	36,001	9,162	45,164	76	1,326	85	1,487
30	Full Service MWH Sales	12,685,410	12,685,410	4,199,402	2,979,606	7,179,008	10,776	54,640	99,352	164,769
31	ROA MWH Sales	-	-	18,702	174,288	192,989	-	-	-	-
32	MWH Sales	12,685,410	12,685,410	4,218,104	3,153,894	7,371,997	10,776	54,640	99,352	164,769
33	Customers	1,680,798	1,680,798	206,948	20,624	227,572	399	4,696	465	5,560

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Rate Base**	191,016	52,747	76,959	753,675	150,865	265,404	612,942	-	35,194	7,635	1,538	2,147,976
2	**Revenue**												
3	Total Rate Revenue	74,753	36,612	43,543	338,711	84,459	123,728	243,505	-	21,316	4,447	719	971,793
4	Total Revenue Credits	11,638	7,714	8,329	57,045	19,613	24,759	42,294	-	5,456	889	109	177,844
5	Total Revenue	86,390	44,326	51,872	395,756	104,072	148,488	285,800	-	26,771	5,336	827	1,149,637
6	**Expenses:**												
7	Fuel and P&I Expense	36,058	23,149	25,387	175,972	56,603	72,780	126,003	-	16,420	2,625	352	535,347
8	Transmission Expense	13,514	7,369	8,461	62,847	17,407	23,367	41,534	-	5,187	817	127	180,630
9	Other O & M Expense	7,216	2,315	2,765	31,259	5,738	8,360	24,815	-	1,552	267	61	84,347
10	Depreciation & Amortization Expense	11,652	4,240	5,258	46,759	10,541	15,627	35,523	-	2,832	493	86	133,012
11	Other Taxes	4,624	1,655	2,153	19,686	4,858	7,426	15,899	-	939	221	41	57,502
12	Federal Income Taxes	976	410	575	4,339	654	1,533	3,079	-	(12)	67	12	11,633
13	Total Expenses	74,040	39,139	44,599	340,862	95,800	129,092	246,853	-	26,918	4,489	679	1,002,471
14	Net Operating Income	12,350	5,187	7,272	54,894	8,272	19,395	38,947	-	(146)	847	148	147,166
15	Other Income Adjustments	227	79	104	984	190	324	765	-	53	10	2	2,737
16	Adjusted Net Operating Income	12,577	5,266	7,376	55,878	8,461	19,720	39,711	-	(94)	857	150	149,903
17	Return on Rate Base @ 6.12%	11,683	3,226	4,707	46,096	9,227	16,233	37,489	-	2,153	467	94	131,375
18	Income Deficiency (Sufficiency)	(894)	(2,040)	(2,669)	(9,782)	766	(3,487)	(2,223)	-	2,246	(390)	(56)	(18,528)
19	Revenue Deficiency (Sufficiency)	(1,196)	(2,729)	(3,572)	(13,089)	1,025	(4,666)	(2,974)	-	3,005	(522)	(74)	(24,792)
20	Additional Rev Requirement	1,316	778	881	6,211	1,633	2,327	4,197	-	524	80	9	17,957
21	Total Revenue Deficiency (Sufficiency)	120	(1,952)	(2,691)	(6,877)	2,658	(2,339)	1,223	-	3,530	(442)	(65)	(6,835)
22	Revenue Requirement/Total Cost of Service	86,510	42,374	49,181	388,879	106,730	146,149	287,023	-	30,301	4,894	762	1,142,802
23	Less: Revenue Credits	11,638	7,714	8,329	57,045	19,613	24,759	42,294	-	5,456	889	109	177,844
24	**Proposed Rate Design Revenue**	**74,873**	**34,660**	**40,852**	**331,834**	**87,117**	**121,390**	**244,729**	**-**	**24,846**	**4,005**	**653**	**964,958**
25	Production: Net Capacity Cost	17,058	8,323	9,663	77,137	17,379	25,604	52,881	-	5,397	808	108	214,359
26	Production: Capacity Related Cost Offset	7,450	4,423	4,960	36,502	10,609	14,016	26,511	-	3,884	614	85	109,054
27	Production: Non-Capacity Related Cost	31,311	19,149	21,389	150,828	46,966	60,723	104,206	-	13,712	2,183	323	450,790
28	Distribution: Demand Related Cost	16,105	2,589	4,378	62,261	11,517	20,060	57,062	-	1,758	366	124	176,219
29	Distribution: Customer Related Cost	2,948	176	462	5,105	646	987	4,069	-	96	35	13	14,537
30	Full Service MWH Sales	666,952	464,518	496,642	3,312,240	1,167,540	1,453,040	2,414,780	-	332,592	53,237	6,737	10,368,279
31	ROA MWH Sales	72,068	-	-	-	1,270,576	1,080,207	953,091	-	-	-	-	3,375,942
32	MWH Sales	739,020	464,518	496,642	3,312,240	2,438,116	2,533,246	3,367,871	-	332,592	53,237	6,737	13,744,220
33	Customers	1,420	23	80	1,413	36	98	1,077	-	5	7	5	4,165

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Net Plant**						
2	Production	2,251,061	1,091,433	544,184	6,369	600,510	8,565
3	Transmission	-	-	-	-	-	-
4	Distribution	9,996,812	5,978,822	2,637,214	189,819	1,170,168	20,788
5	General/Common/Intangible	730,148	455,557	177,035	5,500	90,938	1,117
6	Plant Purchased/Sold	0	0	0	0	0	0
7	Total Net Plant	12,978,021	7,525,813	3,358,434	201,688	1,861,616	30,470
8	**Working Capital**						
9	Total Current Assets	3,131,271	1,873,361	768,056	28,424	456,093	5,337
10	Total Current Liabilities	1,019,384	608,060	257,111	15,848	136,361	2,004
11	Total Working Capital	2,111,887	1,265,301	510,945	12,576	319,732	3,333
	Adjustments to Rate Base						
13	Additions to Rate Base	0	0	0	0	0	0
14	Deductions from Rate Base	66,473	21,311	10,102	158	33,372	1,530
15	Total Adjustments to Rate Base	(66,473)	(21,311)	(10,102)	(158)	(33,372)	(1,530)
16	**Total Rate Base**	**15,023,435**	**8,769,803**	**3,859,277**	**214,106**	**2,147,976**	**32,273**
17	**Production Expense**						
18	Fuel Expense	551,095	230,775	132,182	2,924	182,270	2,943
19	Purchased & Interchange Power Expense	1,138,704	501,162	273,819	5,130	353,077	5,516
20	Total Fuel and P&I Expense	1,689,799	731,937	406,001	8,054	535,347	8,459
21	Fossil O&M Exp	55,255	26,172	13,336	183	15,337	227
22	Nuclear O&M Exp	0	-	-	-	-	-
23	Hydro O&M Exp	13,209	6,197	3,186	46	3,724	56
23	Other Power Gen O&M Exp	64,631	31,336	15,624	183	17,241	246
24	Other Power Supply O&M Exp	5,268	2,554	1,274	15	1,405	20
25	Total Production O&M Expense	138,363	66,259	33,420	427	37,708	549
26	Total Production (Inc. Fuel and P&I) O&M Expense	1,828,162	798,196	439,421	8,481	573,055	9,008
27	**Transmission & Distribution Expense**						
28	Transmission Expense	635,028	296,007	154,008	2,031	180,630	2,353
29	Direct Assign Transmission	0	-	-	-	-	-
30	Distr Oper Exp	115,755	78,109	28,713	3,444	5,444	44
31	Distr Maint Exp	354,948	238,528	91,776	1,452	22,964	228
32	Total Transmission & Distribution O&M Expense	1,105,731	612,644	274,497	6,928	209,038	2,625
33	**Customer Related Expense**						
34	Customer Accounts Exp	59,788	44,638	9,960	266	4,918	7
35	Customer Service Exp	7,158	4,304	1,229	28	1,577	20
36	Other Customer Exp	16,687	13,850	2,666	85	85	0
37	Total Customer O&M Expense	83,634	62,793	13,855	379	6,581	27
38	**Admin & General Expense**	93,510	58,330	22,681	705	11,651	143
39	**Total O&M Expense**	**3,111,036**	**1,531,963**	**750,454**	**16,492**	**800,324**	**11,804**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Net Plant**									
2	Production	1,091,433	1,091,433	329,170	215,014	544,184	216	1,026	5,127	6,369
3	Transmission	-	-	-	-	-	-	-	-	-
4	Distribution	5,978,822	5,978,822	1,664,780	972,435	2,637,214	6,637	166,460	16,722	189,819
5	General/Common/Intangible	455,557	455,557	111,357	65,678	177,035	275	3,924	1,302	5,500
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0
7	Total Net Plant	7,525,813	7,525,813	2,105,308	1,253,126	3,358,434	7,127	171,410	23,151	201,688
8	**Working Capital**									
9	Total Current Assets	1,873,361	1,873,361	480,893	287,164	768,056	1,230	21,326	5,868	28,424
10	Total Current Liabilities	608,060	608,060	161,735	95,376	257,111	541	13,516	1,791	15,848
11	Total Working Capital	1,265,301	1,265,301	319,157	191,788	510,945	690	7,810	4,077	12,576
	Adjustments to Rate Base									
13	Additions to Rate Base	0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base	21,311	21,311	6,221	3,881	10,102	18	71	69	158
15	Total Adjustments to Rate Base	(21,311)	(21,311)	(6,221)	(3,881)	(10,102)	(18)	(71)	(69)	(158)
16	**Total Rate Base**	**8,769,803**	**8,769,803**	**2,418,244**	**1,441,033**	**3,859,277**	**7,799**	**179,149**	**27,159**	**214,106**
17	**Production Expense**									
18	Fuel Expense	230,775	230,775	77,492	54,690	132,182	185	943	1,796	2,924
19	Purchased & Interchange Power Expense	501,162	501,162	162,184	111,635	273,819	294	1,486	3,350	5,130
20	Total Fuel and P&I Expense	731,937	731,937	239,676	166,325	406,001	479	2,428	5,146	8,054
21	Fossil O&M Exp	26,172	26,172	8,019	5,317	13,336	8	39	136	183
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	6,197	6,197	1,911	1,275	3,186	2	11	34	46
23	Other Power Gen O&M Exp	31,336	31,336	9,451	6,173	15,624	6	29	147	183
24	Other Power Supply O&M Exp	2,554	2,554	770	503	1,274	1	2	12	15
25	Total Production O&M Expense	66,259	66,259	20,151	13,269	33,420	17	81	329	427
26	Total Production (Inc. Fuel and P&I) O&M Expense	798,196	798,196	259,827	179,594	439,421	496	2,510	5,475	8,481
27	**Transmission & Distribution Expense**									
28	Transmission Expense	296,007	296,007	93,071	60,937	154,008	111	427	1,493	2,031
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	78,109	78,109	17,893	10,820	28,713	91	3,157	197	3,444
31	Distr Maint Exp	238,528	238,528	57,695	34,081	91,776	157	698	597	1,452
32	Total Transmission & Distribution O&M Expense	612,644	612,644	168,659	105,838	274,497	359	4,281	2,287	6,928
33	**Customer Related Expense**									
34	Customer Accounts Exp	44,638	44,638	7,475	2,485	9,960	15	195	56	266
35	Customer Service Exp	4,304	4,304	833	395	1,229	2	14	12	28
36	Other Customer Exp	13,850	13,850	2,347	319	2,666	6	71	7	85
37	Total Customer O&M Expense	62,793	62,793	10,655	3,199	13,855	23	280	75	379
38	**Admin & General Expense**	58,330	58,330	14,267	8,414	22,681	35	503	167	705
39	**Total O&M Expense**	**1,531,963**	**1,531,963**	**453,408**	**297,045**	**750,454**	**914**	**7,574**	**8,004**	**16,492**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate - GPTU Vlt 1	(d) Rate - GPTU Vlt 2	(e) Rate - GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Net Plant**												
2	Production	45,285	24,434	27,719	210,193	52,655	74,393	146,570	-	16,401	2,528	332	600,510
3	Transmission	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	113,120	18,926	34,246	395,903	86,139	149,534	355,007	-	12,690	3,674	929	1,170,168
5	General/Common/Intangible	7,597	2,708	3,228	33,242	6,565	9,608	25,815	-	1,807	306	62	90,938
6	Plant Purchased/Sold	0	0	0	0	0	0	0	-	0	0	0	0
7	Total Net Plant	166,001	46,068	65,194	639,338	145,359	233,535	527,392	-	30,898	6,508	1,324	1,861,616
8	**Working Capital**												
9	Total Current Assets	37,433	14,476	17,397	162,852	35,458	51,992	124,937	-	9,543	1,692	314	456,093
10	Total Current Liabilities	12,101	3,548	4,776	47,756	10,356	16,198	38,698	-	2,361	471	97	136,361
11	Total Working Capital	25,332	10,928	12,621	115,096	25,102	35,793	86,239	-	7,182	1,221	216	319,732
	Adjustments to Rate Base												
13	Additions to Rate Base	0	0	0	0	0	0	0	-	0	0	0	0
14	Deductions from Rate Base	317	4,249	856	760	19,595	3,925	689	-	2,886	94	2	33,372
15	Total Adjustments to Rate Base	(317)	(4,249)	(856)	(760)	(19,595)	(3,925)	(689)	-	(2,886)	(94)	(2)	(33,372)
16	**Total Rate Base**	**191,016**	**52,747**	**76,959**	**753,675**	**150,865**	**265,404**	**612,942**	**-**	**35,194**	**7,635**	**1,538**	**2,147,976**
17	**Production Expense**												
18	Fuel Expense	11,947	7,986	8,695	59,041	20,010	25,273	42,544	-	5,728	922	124	182,270
19	Purchased & Interchange Power Expense	24,111	15,163	16,692	116,931	36,592	47,506	83,459	-	10,692	1,703	228	353,077
20	Total Fuel and P&I Expense	36,058	23,149	25,387	175,972	56,603	72,780	126,003	-	16,420	2,625	352	535,347
21	Fossil O&M Exp	1,125	638	716	5,295	1,394	1,933	3,724	-	435	68	9	15,337
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	270	156	175	1,279	343	472	902	-	107	17	2	3,724
23	Other Power Gen O&M Exp	1,300	702	796	6,035	1,512	2,136	4,208	-	471	73	10	17,241
24	Other Power Supply O&M Exp	106	57	65	492	123	174	343	-	38	6	1	1,405
25	Total Production O&M Expense	2,802	1,553	1,751	13,101	3,372	4,716	9,177	-	1,051	163	21	37,708
26	Total Production (Inc. Fuel and P&I) O&M Expense	38,860	24,702	27,138	189,072	59,975	77,495	135,180	-	17,471	2,788	373	573,055
27	**Transmission & Distribution Expense**												
28	Transmission Expense	13,514	7,369	8,461	62,847	17,407	23,367	41,534	-	5,187	817	127	180,630
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	489	27	21	2,377	137	172	2,193	-	20	3	5	5,444
31	Distr Maint Exp	2,454	148	300	9,411	673	1,322	8,503	-	99	32	22	22,964
32	Total Transmission & Distribution O&M Expense	16,457	7,543	8,782	74,635	18,217	24,861	52,230	-	5,306	852	155	209,038
33	**Customer Related Expense**												
34	Customer Accounts Exp	388	187	220	1,701	434	626	1,225	-	111	23	4	4,918
35	Customer Service Exp	87	53	57	381	279	290	387	-	38	6	1	1,577
36	Other Customer Exp	23	1	2	30	2	4	23	-	1	0	0	85
37	Total Customer O&M Expense	498	241	279	2,111	715	919	1,634	-	150	29	4	6,581
38	**Admin & General Expense**	973	347	414	4,259	841	1,231	3,307	-	232	39	8	11,651
39	**Total O&M Expense**	**56,788**	**32,833**	**36,613**	**270,078**	**79,748**	**104,506**	**192,352**	**-**	**23,158**	**3,708**	**540**	**800,324**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
	Input Allocation Schedules						
1	Energy @ Generation	100.000	42.334	23.958	0.550	32.607	0.551
2	Energy On-Peak @ Generation	100.000	39.971	25.401	0.415	33.785	0.428
3	Energy Off-Peak @ Generation	100.000	44.351	22.080	0.689	32.203	0.677
4	Energy On-Peak @ Generation Summer	100.000	40.928	25.664	0.340	32.633	0.435
5	Energy Off-Peak @ Generation Summer	100.000	44.559	22.282	0.613	31.817	0.729
6	Energy On-Peak @ Generation Non-Summer	100.000	39.409	25.246	0.459	34.462	0.424
7	Energy Off-Peak @ Generation Non-Summer	100.000	44.235	21.967	0.731	32.418	0.648
8	Energy Critical On-Peak @ Gen	100.000	43.354	25.830	0.259	30.251	0.307
9	Energy Summer Mid-Peak @ Gen	100.000	40.028	25.602	0.371	33.516	0.483
10	12CP Dmd @ Generation	100.000	46.613	24.252	0.320	28.444	0.371
11	4CP Dmd @ Generation	100.000	50.536	24.247	0.194	24.700	0.324
12	Class Peak @ Voltage 1	100.000	47.252	22.398	0.351	29.366	0.632
13	Production Revenue	100.000	44.974	24.348	0.406	30.322	(0.051)
14	Distribution Revenue	100.000	61.655	26.328	1.586	10.271	0.160
15	Total Rate Revenue	100.000	51.459	25.118	0.865	22.528	0.031
16	Billed Sales	100.000	37.157	21.594	0.483	40.259	0.508
17	Number Of Customers	100.000	87.628	11.864	0.290	0.217	0.001
18	Weighted Customer	100.000	60.168	28.620	0.054	11.121	0.038
		-					
	*Calculated Allocation Schedules						
19	4CP 75/0/25	100.000	48.485	24.175	0.283	26.677	0.380
20	Class Peak @ Voltage 2	100.000	50.207	23.799	0.373	24.949	0.672
21	Class Peak Voltage 1 Only	100.000	-	-	-	95.425	4.575
22	Class Peak Voltage 2 Only	100.000	-	-	-	95.387	4.613
23	Class Peak @ Voltage 1 excluding Voltage 2	100.000	50.330	23.857	0.374	25.065	0.373
24	Class Peak @ Voltage 3	100.000	53.875	25.538	0.400	20.109	0.077
25	Class Peak @ Voltage 4	100.000	67.502	31.997	0.501	-	-
26	Class Peak for Streetlighting	100.000	-	-	100.000	-	-
27	Class Peak @ Single Phase	100.000	67.502	31.997	0.501	-	-
28	Billed Sales - Primary	100.000	45.911	26.681	0.596	26.744	0.067
29	Customers - Residential	100.000	100.000	-	-	-	-
30	Customers - Commercial Secondary	100.000	-	100.000	-	-	-
31	Customers - Non-Primary	100.000	88.057	11.922	0.021	-	-
32	Customers - Non-Lighting	100.000	87.883	11.899	-	0.218	0.001
33	Customers - Commercial & Primary	100.000	-	98.197	-	1.797	0.006
34	Customer Count (CCC)	100.000	93.559	6.441	-	-	-
35	Customer Count (BCC)	100.000	-	91.991	4.573	3.425	0.012
36	PIS - HVD (Voltage 1)	100.000	50.444	23.912	0.375	24.659	0.611
37	PIS - HVD (Voltage 2)	100.000	50.117	23.756	0.372	25.218	0.537
38	PIS - HVD (Voltage 1) Substations	100.000	50.207	23.799	0.373	24.949	0.672
39	PIS - HVD (Voltage 2) Substations	100.000	41.526	19.684	0.309	37.365	1.117
40	PIS - OH LVD System	100.000	63.654	30.173	0.473	5.678	0.022
41	PIS - LVD Distribution	100.000	63.002	26.146	2.447	8.285	0.119
42	PIS- OH (LVD & HVD) Lines & Services	100.000	66.221	25.692	0.389	7.606	0.092
43	PIS- UG LVD Distribution	100.000	63.298	30.005	0.470	6.142	0.085
44	PIS- Total Distribution	100.000	61.246	25.825	2.162	10.587	0.180

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
	Input Allocation Schedules									
1	Energy @ Generation	42.334	42.334	14.014	9.944	23.958	0.036	0.182	0.332	0.550
2	Energy On-Peak @ Generation	39.971	39.971	15.138	10.263	25.401	0.018	0.095	0.302	0.415
3	Energy Off-Peak @ Generation	44.351	44.351	12.612	9.467	22.080	0.055	0.274	0.359	0.689
4	Energy On-Peak @ Generation Summer	40.928	40.928	15.333	10.331	25.664	0.008	0.058	0.274	0.340
5	Energy Off-Peak @ Generation Summer	44.559	44.559	12.738	9.544	22.282	0.046	0.235	0.333	0.613
6	Energy On-Peak @ Generation Non-Summer	39.409	39.409	15.023	10.224	25.246	0.023	0.117	0.318	0.459
7	Energy Off-Peak @ Generation Non-Summer	44.235	44.235	12.542	9.425	21.967	0.061	0.297	0.374	0.731
8	Energy Critical On-Peak @ Gen	43.354	43.354	15.496	10.334	25.830	0.001	0.004	0.253	0.259
9	Energy Summer Mid-Peak @ Gen	40.028	40.028	15.273	10.330	25.602	0.011	0.078	0.282	0.371
10	12CP Dmd @ Generation	46.613	46.613	14.656	9.596	24.252	0.017	0.067	0.235	0.320
11	4CP Dmd @ Generation	50.536	50.536	14.826	9.421	24.247	0.001	-	0.193	0.194
12	Class Peak @ Voltage 1	47.252	47.252	13.794	8.604	22.398	0.039	0.159	0.153	0.351
13	Production Revenue	44.974	44.974	14.471	9.877	24.348	0.022	0.108	0.276	0.406
14	Distribution Revenue	61.655	61.655	17.136	9.192	26.328	0.053	1.379	0.154	1.586
15	Total Rate Revenue	51.459	51.459	15.507	9.611	25.118	0.034	0.602	0.228	0.865
16	Billed Sales	37.157	37.157	12.355	9.238	21.594	0.032	0.160	0.291	0.483
17	Number Of Customers	87.628	87.628	10.789	1.075	11.864	0.021	0.245	0.024	0.290
18	Weighted Customer	60.168	60.168	23.310	5.310	28.620	0.054	-	-	0.054
	*Calculated Allocation Schedules									
19	4CP 75/0/25	48.485	48.485	14.623	9.552	24.175	0.010	0.046	0.228	0.283
20	Class Peak @ Voltage 2	50.207	50.207	14.657	9.142	23.799	0.042	0.168	0.163	0.373
21	Class Peak Voltage 1 Only	-	-	-	-	-	-	-	-	-
22	Class Peak Voltage 2 Only	-	-	-	-	-	-	-	-	-
23	Class Peak @ Voltage 1 excluding Voltage 2	50.330	50.330	14.693	9.165	23.857	0.042	0.169	0.163	0.374
24	Class Peak @ Voltage 3	53.875	53.875	15.728	9.810	25.538	0.045	0.181	0.175	0.400
25	Class Peak @ Voltage 4	67.502	67.502	19.705	12.291	31.997	0.056	0.226	0.219	0.501
26	Class Peak for Streetlighting	-	-	-	-	-	19.934	80.066	-	100.000
27	Class Peak @ Single Phase	67.502	67.502	19.705	12.291	31.997	0.056	0.226	0.219	0.501
28	Billed Sales - Primary	45.911	45.911	15.266	11.415	26.681	0.039	0.198	0.360	0.596
29	Customers - Residential	100.000	100.000	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	90.937	9.063	100.000	-	-	-	-
31	Customers - Non-Primary	88.057	88.057	10.842	1.080	11.922	0.021	-	-	0.021
32	Customers - Non-Lighting	87.883	87.883	10.821	1.078	11.899	-	-	-	-
33	Customers - Commercial & Primary	-	-	89.298	8.899	98.197	-	-	-	-
34	Customer Count (CCC)	93.559	93.559	6.388	0.054	6.441	-	-	-	-
35	Customer Count (BCC)	-	-	75.821	16.170	91.991	0.328	3.862	0.382	4.573
36	PIS - HVD (Voltage 1)	50.444	50.444	14.726	9.186	23.912	0.042	0.169	0.163	0.375
37	PIS - HVD (Voltage 2)	50.117	50.117	14.630	9.126	23.756	0.042	0.168	0.162	0.372
38	PIS - HVD (Voltage 1) Substations	50.207	50.207	14.657	9.142	23.799	0.042	0.168	0.163	0.373
39	PIS - HVD (Voltage 2) Substations	41.526	41.526	12.122	7.562	19.684	0.035	0.139	0.135	0.309
40	PIS - OH LVD System	63.654	63.654	18.582	11.591	30.173	0.053	0.214	0.206	0.473
41	PIS - LVD Distribution	63.002	63.002	16.653	9.494	26.146	0.073	2.212	0.162	2.447
42	PIS- OH (LVD & HVD) Lines & Services	66.221	66.221	16.077	9.616	25.692	0.044	0.176	0.170	0.389
43	PIS- UG LVD Distribution	63.298	63.298	18.478	11.526	30.005	0.053	0.212	0.205	0.470
44	PIS- Total Distribution	61.246	61.246	16.379	9.446	25.825	0.069	1.931	0.162	2.162

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
	Input Allocation Schedules												
1	Energy @ Generation	2.150	1.465	1.585	10.685	3.349	4.368	7.764	-	1.049	0.170	0.022	32.607
2	Energy On-Peak @ Generation	2.440	1.416	1.622	11.589	3.460	4.462	7.568	-	1.039	0.159	0.031	33.785
3	Energy Off-Peak @ Generation	1.808	1.499	1.524	9.564	3.874	4.768	7.930	-	1.046	0.180	0.011	32.203
4	Energy On-Peak @ Generation Summer	2.409	1.340	1.533	11.297	3.238	4.192	7.519	-	0.935	0.141	0.028	32.633
5	Energy Off-Peak @ Generation Summer	1.808	1.443	1.491	9.569	3.738	4.561	8.048	-	0.983	0.166	0.011	31.817
6	Energy On-Peak @ Generation Non-Summer	2.458	1.460	1.674	11.761	3.591	4.621	7.596	-	1.100	0.169	0.033	34.462
7	Energy Off-Peak @ Generation Non-Summer	1.808	1.530	1.543	9.561	3.950	4.883	7.865	-	1.081	0.187	0.012	32.418
8	Energy Critical On-Peak @ Gen	2.235	1.207	1.395	10.577	2.859	3.859	7.118	-	0.868	0.116	0.016	30.251
9	Energy Summer Mid-Peak @ Gen	2.473	1.390	1.584	11.565	3.379	4.315	7.667	-	0.960	0.151	0.033	33.516
10	12CP Dmd @ Generation	2.128	1.160	1.332	9.897	2.741	3.680	6.541	-	0.817	0.129	0.020	28.444
11	4CP Dmd @ Generation	1.966	0.959	1.113	8.888	2.003	2.950	6.093	-	0.622	0.093	0.012	24.700
12	Class Peak @ Voltage 1	2.153	0.934	1.007	8.173	4.307	4.620	7.408	-	0.634	0.111	0.019	29.366
13	Production Revenue	2.117	1.364	1.489	10.138	3.119	4.092	7.041	-	0.815	0.130	0.017	30.322
14	Distribution Revenue	1.063	0.075	0.271	4.104	0.268	1.010	3.356	-	0.043	0.064	0.016	10.271
15	Total Rate Revenue	1.707	0.863	1.016	7.792	2.010	2.894	5.609	-	0.515	0.104	0.016	22.528
16	Billed Sales	2.165	1.361	1.455	9.702	7.142	7.420	9.865	-	0.974	0.156	0.020	40.259
17	Number Of Customers	0.074	0.001	0.004	0.074	0.002	0.005	0.056	-	0.000	0.000	0.000	0.217
18	Weighted Customer	3.005	0.071	0.361	4.140	0.125	0.303	3.065	-	0.019	0.021	0.011	11.121
		-	-	-	-	-	-	-	-	-	-	-	-
	*Calculated Allocation Schedules	-	-	-	-	-	-	-	-	-	-	-	-
19	4CP 75/0/25	2.012	1.085	1.231	9.338	2.339	3.305	6.511	-	0.729	0.112	0.015	26.677
20	Class Peak @ Voltage 2	2.277	-	1.070	8.684	-	4.908	7.871	-	-	0.118	0.020	24.949
21	Class Peak Voltage 1 Only	0.163	15.143	-	-	69.834	-	-	-	10.285	-	-	95.425
22	Class Peak Voltage 2 Only	1.574	-	16.464	-	-	75.532	-	-	-	1.817	-	95.387
23	Class Peak @ Voltage 1 excluding Voltage 2	2.191	0.995	-	8.705	4.588	-	7.891	-	0.676	-	0.020	25.065
24	Class Peak @ Voltage 3	2.323	-	-	9.318	-	-	8.447	-	-	-	0.022	20.109
25	Class Peak @ Voltage 4	-	-	-	-	-	-	-	-	-	-	-	-
26	Class Peak for Streetlighting	-	-	-	-	-	-	-	-	-	-	-	-
27	Class Peak @ Single Phase	-	-	-	-	-	-	-	-	-	-	-	-
28	Billed Sales - Primary	2.543	-	-	11.988	-	-	12.189	-	-	-	0.024	26.744
29	Customers - Residential	-	-	-	-	-	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	-	-	-	-	-	-	-	-	-	-
31	Customers - Non-Primary	-	-	-	-	-	-	-	-	-	-	-	-
32	Customers - Non-Lighting	0.074	0.001	0.004	0.074	0.002	0.005	0.056	-	0.000	0.000	0.000	0.218
33	Customers - Commercial & Primary	0.613	0.010	0.035	0.610	0.016	0.042	0.465	-	0.002	0.003	0.002	1.797
34	Customer Count (CCC)	-	-	-	-	-	-	-	-	-	-	-	-
35	Customer Count (BCC)	1.168	0.019	0.066	1.162	0.030	0.080	0.886	-	0.004	0.006	0.004	3.425
36	PIS - HVD (Voltage 1)	2.276	0.048	0.953	8.725	0.220	4.371	7.909	-	0.032	0.105	0.020	24.659
37	PIS - HVD (Voltage 2)	1.945	-	1.687	7.157	-	7.739	6.487	-	-	0.186	0.017	25.218
38	PIS - HVD (Voltage 1) Substations	2.277	-	1.070	8.684	-	4.908	7.871	-	-	0.118	0.020	24.949
39	PIS - HVD (Voltage 2) Substations	2.151	-	3.774	7.182	-	17.314	6.510	-	-	0.417	0.017	37.365
40	PIS - OH LVD System	0.656	-	-	2.631	-	-	2.385	-	-	-	0.006	5.678
41	PIS - LVD Distribution	0.890	0.188	0.116	2.990	0.853	0.441	2.663	-	0.126	0.012	0.007	8.285
42	PIS- OH (LVD & HVD) Lines & Services	0.775	0.042	0.129	3.055	0.194	0.592	2.769	-	0.029	0.014	0.007	7.606
43	PIS- UG LVD Distribution	0.557	0.206	0.008	2.223	0.950	0.037	2.015	-	0.140	0.001	0.005	6.142
44	PIS- Total Distribution	1.051	0.164	0.297	3.637	0.746	1.285	3.256	-	0.110	0.032	0.009	10.587

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	*Calculated Allocation Schedules						
2	PIS- Distribution Services	100.000	94.121	5.879	-	-	-
3	PIS- Streetlighting Equipment	100.000	-	-	100.000	-	-
4	PIS- Line Equipment	100.000	66.184	31.372	0.492	1.944	0.007
5	PIS- Meters	100.000	60.168	28.620	0.054	11.121	0.038
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000
7	Total PIS	100.000	58.715	25.369	1.672	14.024	0.219
8	Distribution Depreciation	100.000	64.799	24.619	2.708	7.763	0.111
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	100.000	35.783	16.962	0.266	45.401	1.588
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	100.000	50.502	23.939	0.375	24.694	0.491
11	PIS- LVD OH Lines & Services	100.000	68.843	26.036	0.392	4.711	0.018
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	100.000	-	-	-	95.425	4.575
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	100.000	52.165	24.727	0.388	22.394	0.327
14	CWIP	100.000	57.180	26.253	0.468	15.864	0.235
15	Rate Base- Total	100.000	58.374	25.688	1.425	14.298	0.215
16	Dist Op Expense (LVD) excl Sup & Eng	100.000	67.912	24.848	3.035	4.181	0.025
17	Dist Maint Expense (LVD) excl Sup & Eng	100.000	68.695	26.092	0.413	4.781	0.018
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.156	21.405	0.335	32.173	0.930
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.597	21.614	0.339	31.552	0.899
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.626	23.524	0.369	25.955	0.526
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.354	23.395	0.367	26.347	0.537
22	Total HVD Distribution O&M Expense	100.000	48.235	22.864	0.358	27.896	0.646
23	Total Distribution O&M Expense (excl. HVD)	100.000	68.541	25.773	1.077	4.590	0.019
24	Total Customer Accounts Expense (excl. Supv)	100.000	74.660	16.658	0.445	8.225	0.012
25	Total Customer Accounts & Service Expense	100.000	73.106	16.713	0.439	9.702	0.040
26	Pre Tax NOI	100.000	50.299	27.586	1.334	20.301	0.480
27	Depreciation & Amortization Expense	100.000	56.557	24.937	1.707	16.562	0.237
28	Non PSCR O&M Expense	100.000	64.107	24.223	0.815	10.728	0.126
29	Distribution Depreciation Expense	100.000	61.455	25.640	2.973	9.782	0.150
30	Gen/Comm/Int Depreciation Expense	100.000	62.379	24.255	0.754	12.459	0.153
31	Production Labor	100.000	48.485	24.175	0.283	26.677	0.380
32	Total Labor	100.000	62.379	24.255	0.754	12.459	0.153
33	50% O&M, 50% Net Plant	100.000	56.298	25.538	1.356	16.545	0.263
34	50/50 PIS & Labor	100.000	60.547	24.812	1.213	13.242	0.186

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	*Calculated Allocation Schedules									
2	PIS- Distribution Services	94.121	94.121	5.347	0.533	5.879	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	1.423	98.577	-	100.000
4	PIS- Line Equipment	66.184	66.184	19.321	12.052	31.372	0.055	0.222	0.214	0.492
5	PIS- Meters	60.168	60.168	23.310	5.310	28.620	0.054	-	-	0.054
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Total PIS	58.715	58.715	15.935	9.434	25.369	0.054	1.441	0.177	1.672
8	Distribution Depreciation	64.799	64.799	15.776	8.843	24.619	0.074	2.484	0.150	2.708
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	35.783	35.783	10.446	6.516	16.962	0.030	0.120	0.116	0.266
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	50.502	50.502	14.743	9.196	23.939	0.042	0.169	0.164	0.375
11	PIS- LVD OH Lines & Services	68.843	68.843	16.328	9.708	26.036	0.044	0.177	0.171	0.392
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	-	-	-	-	-	-	-	-	-
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	52.165	52.165	15.228	9.499	24.727	0.044	0.175	0.169	0.388
14	CWIP	57.180	57.180	16.159	10.094	26.253	0.035	0.231	0.202	0.468
15	Rate Base- Total	58.374	58.374	16.096	9.592	25.688	0.052	1.192	0.181	1.425
16	Dist Op Expense (LVD) excl Sup & Eng	67.912	67.912	15.488	9.359	24.848	0.080	2.785	0.170	3.035
17	Dist Maint Expense (LVD) excl Sup & Eng	68.695	68.695	16.426	9.666	26.092	0.045	0.199	0.169	0.413
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	45.156	45.156	13.182	8.223	21.405	0.038	0.151	0.146	0.335
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	45.597	45.597	13.311	8.303	21.614	0.038	0.153	0.148	0.339
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	49.626	49.626	14.487	9.037	23.524	0.041	0.166	0.161	0.369
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	49.354	49.354	14.408	8.987	23.395	0.041	0.166	0.160	0.367
22	Total HVD Distribution O&M Expense	48.235	48.235	14.081	8.783	22.864	0.040	0.162	0.156	0.358
23	Total Distribution O&M Expense (excl. HVD)	68.541	68.541	16.185	9.589	25.773	0.053	0.854	0.170	1.077
24	Total Customer Accounts Expense (excl. Supv)	74.660	74.660	12.502	4.156	16.658	0.026	0.326	0.093	0.445
25	Total Customer Accounts & Service Expense	73.106	73.106	12.410	4.302	16.713	0.026	0.312	0.101	0.439
26	Pre Tax NOI	50.299	50.299	17.773	9.813	27.586	0.036	1.111	0.187	1.334
27	Depreciation & Amortization Expense	56.557	56.557	15.713	9.224	24.937	0.049	1.476	0.182	1.707
28	Non PSCR O&M Expense	64.107	64.107	15.347	8.876	24.223	0.041	0.600	0.174	0.815
29	Distribution Depreciation Expense	61.455	61.455	16.620	9.020	25.640	0.080	2.745	0.148	2.973
30	Gen/Comm/Int Depreciation Expense	62.379	62.379	15.257	8.998	24.255	0.038	0.538	0.178	0.754
31	Production Labor	48.485	48.485	14.623	9.552	24.175	0.010	0.046	0.228	0.283
32	Total Labor	62.379	62.379	15.257	8.998	24.255	0.038	0.538	0.178	0.754
33	50% O&M, 50% Net Plant	56.298	56.298	15.903	9.635	25.538	0.050	1.112	0.194	1.356
34	50/50 PIS & Labor	60.547	60.547	15.596	9.216	24.812	0.046	0.989	0.177	1.213

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	*Calculated Allocation Schedules												
2	PIS- Distribution Services	-	-	-	-	-	-	-	-	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	-	-	-	-	-	-	-
4	PIS- Line Equipment	0.225	-	-	0.901	-	-	0.817	-	-	-	0.002	1.944
5	PIS- Meters	3.005	0.071	0.361	4.140	0.125	0.303	3.065	-	0.019	0.021	0.011	11.121
6	PIS - General	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-	0.000	0.000	0.000	0.000
7	Total PIS	1.247	0.369	0.500	4.874	1.084	1.701	3.944	-	0.247	0.049	0.010	14.024
8	Distribution Depreciation	0.843	0.096	0.182	2.839	0.430	0.751	2.532	-	0.063	0.019	0.007	7.763
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	1.599	5.085	-	6.189	23.450	-	5.610	-	3.454	-	0.014	45.401
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	2.278	-	1.008	8.735	-	4.623	7.918	-	-	0.111	0.020	24.694
11	PIS- LVD OH Lines & Services	0.544	-	-	2.183	-	-	1.979	-	-	-	0.005	4.711
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	0.163	15.143	-	-	69.834	-	-	-	10.285	-	-	95.425
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	2.301	-	0.504	9.023	-	2.311	8.178	-	-	0.056	0.021	22.394
14	CWIP	1.316	0.457	0.603	5.704	1.099	1.879	4.431	-	0.307	0.058	0.011	15.864
15	Rate Base- Total	1.271	0.351	0.512	5.017	1.004	1.767	4.080	-	0.234	0.051	0.010	14.298
16	Dist Op Expense (LVD) excl Sup & Eng	0.382	0.011	(0.005)	1.911	0.061	0.043	1.766	-	0.009	0.000	0.004	4.181
17	Dist Maint Expense (LVD) excl Sup & Eng	0.573	0.001	0.004	2.203	0.002	0.004	1.989	-	0.000	0.000	0.005	4.781
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	2.017	2.005	0.463	7.810	9.244	2.124	7.080	-	1.361	0.051	0.018	32.173
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	2.037	1.860	0.485	7.887	8.576	2.224	7.149	-	1.263	0.054	0.018	31.552
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	2.265	-	1.282	8.584	-	5.882	7.780	-	-	0.142	0.020	25.955
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	2.261	-	1.367	8.537	-	6.273	7.738	-	-	0.151	0.020	26.347
22	Total HVD Distribution O&M Expense	2.194	0.561	1.097	8.343	2.585	5.033	7.562	-	0.381	0.121	0.019	27.896
23	Total Distribution O&M Expense (excl. HVD)	0.521	0.002	0.000	2.119	0.012	0.006	1.923	-	0.002	0.000	0.005	4.590
24	Total Customer Accounts Expense (excl. Supv)	0.649	0.312	0.368	2.845	0.726	1.047	2.049	-	0.186	0.038	0.006	8.225
25	Total Customer Accounts & Service Expense	0.709	0.358	0.414	3.109	1.065	1.367	2.407	-	0.223	0.043	0.007	9.702
26	Pre Tax NOI	1.704	0.716	1.003	7.573	1.141	2.676	5.373	-	(0.020)	0.117	0.020	20.301
27	Depreciation & Amortization Expense	1.451	0.528	0.655	5.822	1.312	1.946	4.423	-	0.353	0.061	0.011	16.562
28	Non PSCR O&M Expense	0.918	0.294	0.352	3.976	0.730	1.063	3.156	-	0.197	0.034	0.008	10.728
29	Distribution Depreciation Expense	1.113	0.140	0.264	3.435	0.623	1.049	3.032	-	0.092	0.027	0.008	9.782
30	Gen/Comm/Int Depreciation Expense	1.041	0.371	0.442	4.555	0.899	1.316	3.537	-	0.248	0.042	0.009	12.459
31	Production Labor	2.012	1.085	1.231	9.338	2.339	3.305	6.511	-	0.729	0.112	0.015	26.677
32	Total Labor	1.041	0.371	0.442	4.555	0.899	1.316	3.537	-	0.248	0.042	0.009	12.459
33	50% O&M, 50% Net Plant	1.385	0.490	0.633	5.652	1.399	2.101	4.473	-	0.336	0.063	0.012	16.545
34	50/50 PIS & Labor	1.144	0.370	0.471	4.714	0.992	1.509	3.741	-	0.247	0.045	0.009	13.242

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Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Rate Base**	15,023,435	8,712,296	3,829,755	213,682	2,235,944	31,757
2	**Revenue**						
3	Total Rate Revenue	4,459,875	2,322,632	1,124,490	39,481	971,793	1,478
4	Total Revenue Credits	1,186,355	252,810	134,728	3,076	778,823	16,918
5	Total Revenue	5,646,230	2,575,442	1,259,218	42,557	1,750,616	18,396
6	**Expenses:**						
7	Fuel and P&I Expense	2,166,028	731,937	406,001	8,054	1,011,576	8,459
8	Transmission Expense	758,515	296,007	154,008	2,031	304,117	2,353
9	Other O & M Expense	786,210	501,899	189,347	6,392	87,599	972
10	Depreciation & Amortization Expense	803,119	452,579	199,439	13,700	135,511	1,889
11	Other Taxes	350,149	194,962	92,273	1,914	60,073	927
12	Federal Income Taxes	57,300	29,159	15,980	767	11,116	278
13	Total Expenses	4,921,320	2,206,544	1,057,050	32,857	1,609,991	14,879
14	Net Operating Income	724,910	368,898	202,169	9,701	140,625	3,517
15	Other Income Adjustments	17,252	9,787	4,490	80	2,856	40
16	Adjusted Net Operating Income	742,162	378,685	206,658	9,781	143,481	3,557
17	Return on Rate Base @ 6.12%	918,867	532,864	234,236	13,069	136,755	1,942
18	Income Deficiency (Sufficiency)	176,705	154,178	27,578	3,288	(6,726)	(1,615)
19	Revenue Deficiency (Sufficiency)	236,445	206,303	36,902	4,400	(9,000)	(2,161)
20	Additional Rev Requirement	40,158	11,518	10,429	68	17,862	282
21	Total Revenue Deficiency (Sufficiency)	276,603	217,821	47,331	4,468	8,862	(1,879)
22	Revenue Requirement/Total Cost of Service	5,922,834	2,793,264	1,306,549	47,025	1,759,478	16,518
23	Less: Revenue Credits	1,186,355	252,810	134,728	3,076	778,823	16,918
24	**Proposed Rate Design Revenue**	**4,736,478**	**2,540,454**	**1,171,821**	**43,949**	**980,655**	**(400)**
25	Production: Net Capacity Cost	1,142,215	505,086	242,338	1,938	389,617	3,236
26	Production: Capacity Related Cost Offset	339,952	70,664	43,765	1,320	223,206	997
27	Production: Non-Capacity Related Cost	1,150,983	626,183	349,634	6,392	176,122	(7,348)
28	Distribution: Demand Related Cost	1,854,383	1,151,147	491,080	32,815	176,730	2,610
29	Distribution: Customer Related Cost	248,945	187,374	45,004	1,483	14,979	105
30	Full Service MWH Sales	38,454,766	12,685,410	7,179,008	164,769	18,252,279	173,301
31	ROA MWH Sales	3,568,931	-	192,989	-	3,375,942	-
32	MWH Sales	42,023,697	12,685,410	7,371,997	164,769	21,628,220	173,301
33	Customers	1,918,109	1,680,798	227,572	5,560	4,166	14

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Rate Base**	8,712,296	8,712,296	2,400,533	1,429,222	3,829,755	7,779	179,053	26,850	213,682
2	**Revenue**									
3	Total Rate Revenue	2,322,632	2,322,632	696,410	428,081	1,124,490	1,521	28,052	9,908	39,481
4	Total Revenue Credits	252,810	252,810	79,485	55,243	134,728	198	1,160	1,718	3,076
5	Total Revenue	2,575,442	2,575,442	775,895	483,323	1,259,218	1,720	29,212	11,626	42,557
6	**Expenses:**									
7	Fuel and P&I Expense	731,937	731,937	239,676	166,325	406,001	479	2,428	5,146	8,054
8	Transmission Expense	296,007	296,007	93,071	60,937	154,008	111	427	1,493	2,031
9	Other O & M Expense	501,899	501,899	120,006	69,341	189,347	323	4,715	1,354	6,392
10	Depreciation & Amortization Expense	452,579	452,579	125,692	73,746	199,439	390	11,855	1,455	13,700
11	Other Taxes	194,962	194,962	57,011	35,263	92,273	134	1,090	690	1,914
12	Federal Income Taxes	29,159	29,159	10,288	5,693	15,980	21	637	109	767
13	Total Expenses	2,206,544	2,206,544	645,744	411,306	1,057,050	1,458	21,153	10,246	32,857
14	Net Operating Income	368,898	368,898	130,151	72,018	202,169	262	8,059	1,380	9,701
15	Other Income Adjustments	9,787	9,787	2,764	1,726	4,490	6	40	34	80
16	Adjusted Net Operating Income	378,685	378,685	132,915	73,743	206,658	268	8,099	1,414	9,781
17	Return on Rate Base @ 6.12%	532,864	532,864	146,822	87,414	234,236	476	10,951	1,642	13,069
18	Income Deficiency (Sufficiency)	154,178	154,178	13,907	13,671	27,578	208	2,852	228	3,288
19	Revenue Deficiency (Sufficiency)	206,303	206,303	18,609	18,293	36,902	278	3,817	305	4,400
20	Additional Rev Requirement	11,518	11,518	5,845	4,583	10,429	(6)	(49)	123	68
21	Total Revenue Deficiency (Sufficiency)	217,821	217,821	24,454	22,876	47,331	272	3,768	428	4,468
22	Revenue Requirement/Total Cost of Service	2,793,264	2,793,264	800,349	506,200	1,306,549	1,992	32,980	12,054	47,025
23	Less: Revenue Credits	252,810	252,810	79,485	55,243	134,728	198	1,160	1,718	3,076
24	**Proposed Rate Design Revenue**	**2,540,454**	**2,540,454**	**720,864**	**450,957**	**1,171,821**	**1,794**	**31,820**	**10,336**	**43,949**
25	Production: Net Capacity Cost	505,086	505,086	148,178	94,160	242,338	8	-	1,931	1,938
26	Production: Capacity Related Cost Offset	70,664	70,664	25,167	18,598	43,765	95	466	760	1,320
27	Production: Non-Capacity Related Cost	626,183	626,183	207,637	141,997	349,634	379	1,814	4,198	6,392
28	Distribution: Demand Related Cost	1,151,147	1,151,147	303,972	187,108	491,080	1,236	28,215	3,365	32,815
29	Distribution: Customer Related Cost	187,374	187,374	35,910	9,094	45,004	76	1,325	82	1,483
30	Full Service MWH Sales	12,685,410	12,685,410	4,199,402	2,979,606	7,179,008	10,776	54,640	99,352	164,769
31	ROA MWH Sales	-	-	18,702	174,288	192,989	-	-	-	-
32	MWH Sales	12,685,410	12,685,410	4,218,104	3,153,894	7,371,997	10,776	54,640	99,352	164,769
33	Customers	1,680,798	1,680,798	206,948	20,624	227,572	399	4,696	465	5,560

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Rate Base**	188,507	51,307	75,348	741,852	147,586	260,946	604,523	122,670	34,207	7,480	1,518	2,235,944
2	**Revenue**												
3	Total Rate Revenue	74,753	36,612	43,543	338,711	84,459	123,728	243,505	-	21,316	4,447	719	971,793
4	Total Revenue Credits	11,592	7,685	8,298	56,840	19,468	24,608	42,090	601,814	5,435	885	108	778,823
5	Total Revenue	86,345	44,297	51,841	395,551	103,927	148,336	285,596	601,814	26,751	5,333	827	1,750,616
6	**Expenses:**												
7	Fuel and P&I Expense	36,058	23,149	25,387	175,972	56,603	72,780	126,003	476,229	16,420	2,625	352	1,011,576
8	Transmission Expense	13,514	7,369	8,461	62,847	17,407	23,367	41,534	123,487	5,187	817	127	304,117
9	Other O & M Expense	7,121	2,261	2,704	30,817	5,585	8,167	24,479	4,630	1,514	261	60	87,599
10	Depreciation & Amortization Expense	11,582	4,201	5,214	46,430	10,451	15,504	35,290	3,460	2,805	489	86	135,511
11	Other Taxes	4,540	1,605	2,099	19,305	4,650	7,197	15,560	3,957	904	215	40	60,073
12	Federal Income Taxes	991	418	584	4,408	676	1,562	3,130	(729)	(6)	68	12	11,116
13	Total Expenses	73,806	39,003	44,449	339,779	95,372	128,576	245,996	611,034	26,824	4,474	677	1,609,991
14	Net Operating Income	12,539	5,294	7,392	55,772	8,555	19,760	39,600	(9,220)	(73)	858	149	140,625
15	Other Income Adjustments	224	77	102	968	185	318	753	165	52	10	2	2,856
16	Adjusted Net Operating Income	12,762	5,371	7,494	56,740	8,740	20,078	40,353	(9,055)	(22)	868	151	143,481
17	Return on Rate Base @ 6.12%	11,529	3,138	4,608	45,373	9,027	15,960	36,974	7,503	2,092	458	93	136,755
18	Income Deficiency (Sufficiency)	(1,233)	(2,233)	(2,885)	(11,367)	287	(4,118)	(3,379)	16,558	2,114	(411)	(58)	(6,726)
19	Revenue Deficiency (Sufficiency)	(1,650)	(2,988)	(3,861)	(15,210)	383	(5,510)	(4,521)	22,156	2,829	(549)	(78)	(9,000)
20	Additional Rev Requirement	1,320	780	883	6,227	1,644	2,339	4,213	(160)	526	80	9	17,862
21	Total Revenue Deficiency (Sufficiency)	(330)	(2,208)	(2,978)	(8,983)	2,028	(3,171)	(308)	21,996	3,355	(470)	(69)	8,862
22	Revenue Requirement/Total Cost of Service	86,015	42,089	48,863	386,568	105,954	145,164	285,287	623,810	30,106	4,863	758	1,759,478
23	Less: Revenue Credits	11,592	7,685	8,298	56,840	19,468	24,608	42,090	601,814	5,435	885	108	778,823
24	**Proposed Rate Design Revenue**	**74,423**	**34,404**	**40,565**	**329,728**	**86,487**	**120,557**	**243,197**	**21,996**	**24,671**	**3,978**	**650**	**980,655**
25	Production: Net Capacity Cost	19,645	9,585	11,129	88,836	20,014	29,487	60,901	142,750	6,216	930	124	389,617
26	Production: Capacity Related Cost Offset	4,437	2,919	3,224	22,804	7,427	9,386	17,071	152,507	2,901	466	66	223,206
27	Production: Non-Capacity Related Cost	31,322	19,156	21,396	150,877	46,996	60,755	104,251	(274,854)	13,716	2,184	324	176,122
28	Distribution: Demand Related Cost	16,087	2,578	4,365	62,178	11,456	19,997	56,977	855	1,749	364	123	176,730
29	Distribution: Customer Related Cost	2,932	166	451	5,034	594	932	3,996	739	89	34	13	14,979
30	Full Service MWH Sales	666,952	464,518	496,642	3,312,240	1,167,540	1,453,040	2,414,780	7,884,000	332,592	53,237	6,737	18,252,279
31	ROA MWH Sales	72,068	-	-	-	1,270,576	1,080,207	953,091	-	-	-	-	3,375,942
32	MWH Sales	739,020	464,518	496,642	3,312,240	2,438,116	2,533,246	3,367,871	7,884,000	332,592	53,237	6,737	21,628,220
33	Customers	1,420	23	80	1,413	36	98	1,077	1	5	7	5	4,166

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U-21870 Large Load Proposals
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(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	**Net Plant**						
2	Production	2,251,061	1,091,433	544,184	6,369	600,510	8,565
3	Transmission	-	-	-	-	-	-
4	Distribution	9,996,812	5,978,810	2,637,209	189,819	1,170,186	20,788
5	General/Common/Intangible	730,148	441,161	169,724	5,402	112,866	994
6	Plant Purchased/Sold	0	0	0	0	0	0
7	Total Net Plant	12,978,021	7,511,405	3,351,116	201,590	1,883,562	30,347
8	**Working Capital**						
9	Total Current Assets	3,131,271	1,825,764	743,567	28,067	528,968	4,906
10	Total Current Liabilities	1,019,384	603,561	254,826	15,817	143,214	1,965
11	Total Working Capital	2,111,887	1,222,202	488,740	12,250	385,754	2,940
	Adjustments to Rate Base						
13	Additions to Rate Base	0	0	0	0	0	0
14	Deductions from Rate Base	66,473	21,311	10,102	158	33,372	1,530
15	Total Adjustments to Rate Base	(66,473)	(21,311)	(10,102)	(158)	(33,372)	(1,530)
16	**Total Rate Base**	**15,023,435**	**8,712,296**	**3,829,755**	**213,682**	**2,235,944**	**31,757**
17	**Production Expense**						
18	Fuel Expense	551,095	230,775	132,182	2,924	182,270	2,943
19	Purchased & Interchange Power Expense	1,614,933	501,162	273,819	5,130	829,305	5,516
20	Total Fuel and P&I Expense	2,166,028	731,937	406,001	8,054	1,011,576	8,459
21	Fossil O&M Exp	55,255	26,172	13,336	183	15,337	227
22	Nuclear O&M Exp	0	-	-	-	-	-
23	Hydro O&M Exp	13,209	6,197	3,186	46	3,724	56
23	Other Power Gen O&M Exp	64,631	31,336	15,624	183	17,241	246
24	Other Power Supply O&M Exp	5,268	2,554	1,274	15	1,405	20
25	Total Production O&M Expense	138,363	66,259	33,420	427	37,708	549
26	Total Production (Inc. Fuel and P&I) O&M Expense	2,304,390	798,196	439,421	8,481	1,049,284	9,008
27	**Transmission & Distribution Expense**						
28	Transmission Expense	635,028	296,007	154,008	2,031	180,630	2,353
29	Direct Assign Transmission	123,487	-	-	-	123,487	-
30	Distr Oper Exp	115,755	78,110	28,713	3,444	5,444	44
31	Distr Maint Exp	354,948	238,528	91,776	1,452	22,964	228
32	Total Transmission & Distribution O&M Expense	1,229,218	612,644	274,497	6,928	332,525	2,625
33	**Customer Related Expense**						
34	Customer Accounts Exp	59,788	44,638	9,960	266	4,918	7
35	Customer Service Exp	7,158	4,032	1,071	25	2,014	16
36	Other Customer Exp	16,687	13,847	2,664	85	91	0
37	Total Customer O&M Expense	83,634	62,517	13,695	375	7,023	23
38	**Admin & General Expense**	93,510	56,486	21,744	692	14,460	127
39	**Total O&M Expense**	**3,710,752**	**1,529,843**	**749,357**	**16,476**	**1,403,292**	**11,784**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	**Net Plant**									
2	Production	1,091,433	1,091,433	329,170	215,014	544,184	216	1,026	5,127	6,369
3	Transmission	-	-	-	-	-	-	-	-	-
4	Distribution	5,978,810	5,978,810	1,664,775	972,433	2,637,209	6,637	166,460	16,722	189,819
5	General/Common/Intangible	441,161	441,161	106,959	62,765	169,724	270	3,904	1,228	5,402
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0
7	Total Net Plant	7,511,405	7,511,405	2,100,904	1,250,212	3,351,116	7,123	171,390	23,078	201,590
8	**Working Capital**									
9	Total Current Assets	1,825,764	1,825,764	466,211	277,356	743,567	1,214	21,244	5,609	28,067
10	Total Current Liabilities	603,561	603,561	160,361	94,466	254,826	539	13,510	1,768	15,817
11	Total Working Capital	1,222,202	1,222,202	305,850	182,890	488,740	674	7,734	3,841	12,250
	Adjustments to Rate Base									
13	Additions to Rate Base	0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base	21,311	21,311	6,221	3,881	10,102	18	71	69	158
15	Total Adjustments to Rate Base	(21,311)	(21,311)	(6,221)	(3,881)	(10,102)	(18)	(71)	(69)	(158)
16	**Total Rate Base**	**8,712,296**	**8,712,296**	**2,400,533**	**1,429,222**	**3,829,755**	**7,779**	**179,053**	**26,850**	**213,682**
17	**Production Expense**									
18	Fuel Expense	230,775	230,775	77,492	54,690	132,182	185	943	1,796	2,924
19	Purchased & Interchange Power Expense	501,162	501,162	162,184	111,635	273,819	294	1,486	3,350	5,130
20	Total Fuel and P&I Expense	731,937	731,937	239,676	166,325	406,001	479	2,428	5,146	8,054
21	Fossil O&M Exp	26,172	26,172	8,019	5,317	13,336	8	39	136	183
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	6,197	6,197	1,911	1,275	3,186	2	11	34	46
23	Other Power Gen O&M Exp	31,336	31,336	9,451	6,173	15,624	6	29	147	183
24	Other Power Supply O&M Exp	2,554	2,554	770	503	1,274	1	2	12	15
25	Total Production O&M Expense	66,259	66,259	20,151	13,269	33,420	17	81	329	427
26	Total Production (Inc. Fuel and P&I) O&M Expense	798,196	798,196	259,827	179,594	439,421	496	2,510	5,475	8,481
27	**Transmission & Distribution Expense**									
28	Transmission Expense	296,007	296,007	93,071	60,937	154,008	111	427	1,493	2,031
29	Direct Assign Transmission	-	-	-	-	-	-	-	-	-
30	Distr Oper Exp	78,110	78,110	17,893	10,820	28,713	91	3,157	197	3,444
31	Distr Maint Exp	238,528	238,528	57,695	34,081	91,776	157	698	597	1,452
32	Total Transmission & Distribution O&M Expense	612,644	612,644	168,659	105,838	274,497	359	4,281	2,287	6,928
33	**Customer Related Expense**									
34	Customer Accounts Exp	44,638	44,638	7,475	2,485	9,960	15	195	56	266
35	Customer Service Exp	4,032	4,032	743	328	1,071	2	13	10	25
36	Other Customer Exp	13,847	13,847	2,346	318	2,664	6	71	7	85
37	Total Customer O&M Expense	62,517	62,517	10,564	3,131	13,695	23	279	73	375
38	**Admin & General Expense**	56,486	56,486	13,703	8,041	21,744	35	500	157	692
39	**Total O&M Expense**	**1,529,843**	**1,529,843**	**452,753**	**296,604**	**749,357**	**913**	**7,570**	**7,993**	**16,476**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	**Net Plant**												
2	Production	45,285	24,434	27,719	210,193	52,655	74,393	146,570	0	16,401	2,528	332	600,510
3	Transmission	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	113,119	18,926	34,246	395,902	86,138	149,534	355,006	20	12,690	3,674	929	1,170,186
5	General/Common/Intangible	6,979	2,362	2,839	30,352	5,777	8,530	23,763	30,366	1,572	269	58	112,866
6	Plant Purchased/Sold	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Net Plant	165,383	45,722	64,804	636,448	144,571	232,457	525,339	30,386	30,662	6,471	1,319	1,883,562
8	**Working Capital**												
9	Total Current Assets	35,349	13,273	16,053	153,016	32,720	48,274	117,929	101,776	8,719	1,563	297	528,968
10	Total Current Liabilities	11,908	3,439	4,654	46,852	10,109	15,861	38,056	9,492	2,287	459	96	143,214
11	Total Working Capital	23,440	9,834	11,400	106,164	22,610	32,413	79,873	92,284	6,431	1,104	201	385,754
	Adjustments to Rate Base												
13	Additions to Rate Base	0	0	0	0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base	317	4,249	856	760	19,595	3,925	689	-	2,886	94	2	33,372
15	Total Adjustments to Rate Base	(317)	(4,249)	(856)	(760)	(19,595)	(3,925)	(689)	0	(2,886)	(94)	(2)	(33,372)
16	**Total Rate Base**	**188,507**	**51,307**	**75,348**	**741,852**	**147,586**	**260,946**	**604,523**	**122,670**	**34,207**	**7,480**	**1,518**	**2,235,944**
17	**Production Expense**												
18	Fuel Expense	11,947	7,986	8,695	59,041	20,010	25,273	42,544	-	5,728	922	124	182,270
19	Purchased & Interchange Power Expense	24,111	15,163	16,692	116,931	36,592	47,506	83,459	476,229	10,692	1,703	228	829,305
20	Total Fuel and P&I Expense	36,058	23,149	25,387	175,972	56,603	72,780	126,003	476,229	16,420	2,625	352	1,011,576
21	Fossil O&M Exp	1,125	638	716	5,295	1,394	1,933	3,724	-	435	68	9	15,337
22	Nuclear O&M Exp	-	-	-	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp	270	156	175	1,279	343	472	902	0	107	17	2	3,724
23	Other Power Gen O&M Exp	1,300	702	796	6,035	1,512	2,136	4,208	-	471	73	10	17,241
24	Other Power Supply O&M Exp	106	57	65	492	123	174	343	0	38	6	1	1,405
25	Total Production O&M Expense	2,802	1,553	1,751	13,101	3,372	4,716	9,177	0	1,051	163	21	37,708
26	Total Production (Inc. Fuel and P&I) O&M Expense	38,860	24,702	27,138	189,072	59,975	77,495	135,180	476,229	17,471	2,788	373	1,049,284
27	**Transmission & Distribution Expense**												
28	Transmission Expense	13,514	7,369	8,461	62,847	17,407	23,367	41,534	-	5,187	817	127	180,630
29	Direct Assign Transmission	-	-	-	-	-	-	-	123,487	-	-	-	123,487
30	Distr Oper Exp	489	27	21	2,377	137	172	2,193	(0)	20	3	5	5,444
31	Distr Maint Exp	2,454	148	300	9,411	673	1,322	8,503	0	99	32	22	22,964
32	Total Transmission & Distribution O&M Expense	16,457	7,543	8,782	74,635	18,217	24,861	52,230	123,487	5,306	852	155	332,525
33	**Customer Related Expense**												
34	Customer Accounts Exp	388	187	220	1,701	434	626	1,225	0	111	23	4	4,918
35	Customer Service Exp	71	43	46	310	226	235	314	732	31	5	1	2,014
36	Other Customer Exp	23	1	2	29	2	4	22	8	0	0	0	91
37	Total Customer O&M Expense	482	231	268	2,039	663	865	1,562	739	143	28	4	7,023
38	**Admin & General Expense**	894	303	364	3,889	740	1,093	3,044	3,890	201	34	7	14,460
39	**Total O&M Expense**	**56,693**	**32,779**	**36,552**	**269,636**	**79,594**	**104,314**	**192,016**	**604,346**	**23,121**	**3,702**	**539**	**1,403,292**

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
	Input Allocation Schedules						
1	Energy @ Generation	100.000	33.906	19.188	0.440	46.025	0.441
2	Energy On-Peak @ Generation	100.000	32.760	20.818	0.340	45.730	0.351
3	Energy Off-Peak @ Generation	100.000	34.750	17.300	0.540	46.880	0.530
4	Energy On-Peak @ Generation Summer	100.000	34.135	21.405	0.284	43.813	0.363
5	Energy Off-Peak @ Generation Summer	100.000	35.421	17.712	0.487	45.800	0.579
6	Energy On-Peak @ Generation Non-Summer	100.000	31.974	20.483	0.372	46.826	0.344
7	Energy Off-Peak @ Generation Non-Summer	100.000	34.385	17.075	0.569	47.467	0.504
8	Energy Critical On-Peak @ Gen	100.000	36.621	21.818	0.218	41.083	0.259
9	Energy Summer Mid-Peak @ Gen	100.000	33.229	21.254	0.308	44.809	0.401
10	12CP Dmd @ Generation	100.000	39.661	20.635	0.272	39.117	0.315
11	4CP Dmd @ Generation	100.000	44.220	21.216	0.170	34.111	0.283
12	Class Peak @ Voltage 1	100.000	47.252	22.398	0.351	29.366	0.632
13	Production Revenue	100.000	44.974	24.348	0.406	30.322	(0.051)
14	Distribution Revenue	100.000	61.655	26.328	1.586	10.271	0.160
15	Total Rate Revenue	100.000	51.459	25.118	0.865	22.528	0.031
16	Billed Sales	100.000	30.186	17.542	0.392	51.467	0.412
17	Number Of Customers	100.000	87.628	11.864	0.290	0.217	0.001
18	Weighted Customer	100.000	60.166	28.619	0.054	11.124	0.038
		-					
	*Calculated Allocation Schedules						
19	4CP 75/0/25	100.000	41.641	20.709	0.237	37.089	0.323
20	Class Peak @ Voltage 2	100.000	50.207	23.799	0.373	24.949	0.672
21	Class Peak Voltage 1 Only	100.000	-	-	-	95.425	4.575
22	Class Peak Voltage 2 Only	100.000	-	-	-	95.387	4.613
23	Class Peak @ Voltage 1 excluding Voltage 2	100.000	50.330	23.857	0.374	25.065	0.373
24	Class Peak @ Voltage 3	100.000	53.875	25.538	0.400	20.109	0.077
25	Class Peak @ Voltage 4	100.000	67.502	31.997	0.501	-	-
26	Class Peak for Streetlighting	100.000	-	-	100.000	-	-
27	Class Peak @ Single Phase	100.000	67.502	31.997	0.501	-	-
28	Billed Sales - Primary	100.000	45.911	26.681	0.596	26.744	0.067
29	Customers - Residential	100.000	100.000	-	-	-	-
30	Customers - Commercial Secondary	100.000	-	100.000	-	-	-
31	Customers - Non-Primary	100.000	88.057	11.922	0.021	-	-
32	Customers - Non-Lighting	100.000	87.883	11.899	-	0.218	0.001
33	Customers - Commercial & Primary	100.000	-	98.196	-	1.798	0.006
34	Customer Count (CCC)	100.000	93.559	6.441	-	-	-
35	Customer Count (BCC)	100.000	-	91.990	4.572	3.426	0.012
36	PIS - HVD (Voltage 1)	100.000	50.444	23.912	0.375	24.659	0.611
37	PIS - HVD (Voltage 2)	100.000	50.117	23.756	0.372	25.218	0.537
38	PIS - HVD (Voltage 1) Substations	100.000	50.207	23.799	0.373	24.949	0.672
39	PIS - HVD (Voltage 2) Substations	100.000	41.526	19.684	0.309	37.365	1.117
40	PIS - OH LVD System	100.000	63.654	30.173	0.473	5.678	0.022
41	PIS - LVD Distribution	100.000	63.001	26.146	2.447	8.286	0.119
42	PIS- OH (LVD & HVD) Lines & Services	100.000	66.221	25.692	0.389	7.606	0.092
43	PIS- UG LVD Distribution	100.000	63.298	30.005	0.470	6.142	0.085
44	PIS- Total Distribution	100.000	61.246	25.825	2.162	10.587	0.180

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
	Input Allocation Schedules									
1	Energy @ Generation	33.906	33.906	11.224	7.964	19.188	0.029	0.146	0.266	0.440
2	Energy On-Peak @ Generation	32.760	32.760	12.407	8.412	20.818	0.015	0.078	0.248	0.340
3	Energy Off-Peak @ Generation	34.750	34.750	9.882	7.418	17.300	0.043	0.215	0.282	0.540
4	Energy On-Peak @ Generation Summer	34.135	34.135	12.788	8.616	21.405	0.007	0.048	0.229	0.284
5	Energy Off-Peak @ Generation Summer	35.421	35.421	10.126	7.587	17.712	0.036	0.187	0.264	0.487
6	Energy On-Peak @ Generation Non-Summer	31.974	31.974	12.189	8.295	20.483	0.019	0.095	0.258	0.372
7	Energy Off-Peak @ Generation Non-Summer	34.385	34.385	9.749	7.326	17.075	0.047	0.230	0.291	0.569
8	Energy Critical On-Peak @ Gen	36.621	36.621	13.089	8.729	21.818	0.001	0.003	0.214	0.218
9	Energy Summer Mid-Peak @ Gen	33.229	33.229	12.679	8.575	21.254	0.009	0.065	0.234	0.308
10	12CP Dmd @ Generation	39.661	39.661	12.470	8.165	20.635	0.015	0.057	0.200	0.272
11	4CP Dmd @ Generation	44.220	44.220	12.973	8.244	21.216	0.001	-	0.169	0.170
12	Class Peak @ Voltage 1	47.252	47.252	13.794	8.604	22.398	0.039	0.159	0.153	0.351
13	Production Revenue	44.974	44.974	14.471	9.877	24.348	0.022	0.108	0.276	0.406
14	Distribution Revenue	61.655	61.655	17.136	9.192	26.328	0.053	1.379	0.154	1.586
15	Total Rate Revenue	51.459	51.459	15.507	9.611	25.118	0.034	0.602	0.228	0.865
16	Billed Sales	30.186	30.186	10.037	7.505	17.542	0.026	0.130	0.236	0.392
17	Number Of Customers	87.628	87.628	10.789	1.075	11.864	0.021	0.245	0.024	0.290
18	Weighted Customer	60.166	60.166	23.310	5.309	28.619	0.054	-	-	0.054
	*Calculated Allocation Schedules									
19	4CP 75/0/25	41.641	41.641	12.536	8.174	20.709	0.008	0.037	0.193	0.237
20	Class Peak @ Voltage 2	50.207	50.207	14.657	9.142	23.799	0.042	0.168	0.163	0.373
21	Class Peak Voltage 1 Only	-	-	-	-	-	-	-	-	-
22	Class Peak Voltage 2 Only	-	-	-	-	-	-	-	-	-
23	Class Peak @ Voltage 1 excluding Voltage 2	50.330	50.330	14.693	9.165	23.857	0.042	0.169	0.163	0.374
24	Class Peak @ Voltage 3	53.875	53.875	15.728	9.810	25.538	0.045	0.181	0.175	0.400
25	Class Peak @ Voltage 4	67.502	67.502	19.705	12.291	31.997	0.056	0.226	0.219	0.501
26	Class Peak for Streetlighting	-	-	-	-	-	19.934	80.066	-	100.000
27	Class Peak @ Single Phase	67.502	67.502	19.705	12.291	31.997	0.056	0.226	0.219	0.501
28	Billed Sales - Primary	45.911	45.911	15.266	11.415	26.681	0.039	0.198	0.360	0.596
29	Customers - Residential	100.000	100.000	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	90.937	9.063	100.000	-	-	-	-
31	Customers - Non-Primary	88.057	88.057	10.842	1.080	11.922	0.021	-	-	0.021
32	Customers - Non-Lighting	87.883	87.883	10.821	1.078	11.899	-	-	-	-
33	Customers - Commercial & Primary	-	-	89.297	8.899	98.196	-	-	-	-
34	Customer Count (CCC)	93.559	93.559	6.388	0.054	6.441	-	-	-	-
35	Customer Count (BCC)	-	-	75.820	16.170	91.990	0.328	3.862	0.382	4.572
36	PIS - HVD (Voltage 1)	50.444	50.444	14.726	9.186	23.912	0.042	0.169	0.163	0.375
37	PIS - HVD (Voltage 2)	50.117	50.117	14.630	9.126	23.756	0.042	0.168	0.162	0.372
38	PIS - HVD (Voltage 1) Substations	50.207	50.207	14.657	9.142	23.799	0.042	0.168	0.163	0.373
39	PIS - HVD (Voltage 2) Substations	41.526	41.526	12.122	7.562	19.684	0.035	0.139	0.135	0.309
40	PIS - OH LVD System	63.654	63.654	18.582	11.591	30.173	0.053	0.214	0.206	0.473
41	PIS - LVD Distribution	63.001	63.001	16.653	9.493	26.146	0.073	2.212	0.162	2.447
42	PIS- OH (LVD & HVD) Lines & Services	66.221	66.221	16.077	9.616	25.692	0.044	0.176	0.170	0.389
43	PIS- UG LVD Distribution	63.298	63.298	18.478	11.526	30.005	0.053	0.212	0.205	0.470
44	PIS- Total Distribution	61.246	61.246	16.379	9.446	25.825	0.069	1.931	0.162	2.162

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
	Input Allocation Schedules												
1	Energy @ Generation	1.722	1.173	1.269	8.558	2.682	3.499	6.219	19.909	0.840	0.136	0.017	46.025
2	Energy On-Peak @ Generation	2.000	1.160	1.329	9.499	2.836	3.657	6.202	18.040	0.851	0.130	0.025	45.730
3	Energy Off-Peak @ Generation	1.416	1.174	1.194	7.494	3.035	3.736	6.213	21.648	0.819	0.141	0.009	46.880
4	Energy On-Peak @ Generation Summer	2.009	1.118	1.278	9.422	2.701	3.496	6.271	16.597	0.780	0.118	0.023	43.813
5	Energy Off-Peak @ Generation Summer	1.437	1.147	1.185	7.606	2.971	3.626	6.397	20.508	0.781	0.132	0.009	45.800
6	Energy On-Peak @ Generation Non-Summer	1.994	1.184	1.358	9.542	2.913	3.749	6.163	18.866	0.892	0.137	0.027	46.826
7	Energy Off-Peak @ Generation Non-Summer	1.405	1.189	1.199	7.432	3.070	3.796	6.113	22.268	0.840	0.146	0.009	47.467
8	Energy Critical On-Peak @ Gen	1.888	1.020	1.178	8.935	2.415	3.260	6.013	15.530	0.733	0.098	0.013	41.083
9	Energy Summer Mid-Peak @ Gen	2.053	1.154	1.315	9.600	2.805	3.582	6.365	16.986	0.797	0.125	0.027	44.809
10	12CP Dmd @ Generation	1.811	0.987	1.134	8.421	2.332	3.131	5.565	14.915	0.695	0.109	0.017	39.117
11	4CP Dmd @ Generation	1.720	0.839	0.974	7.778	1.752	2.582	5.332	12.498	0.544	0.081	0.011	34.111
12	Class Peak @ Voltage 1	2.153	0.934	1.007	8.173	4.307	4.620	7.408	-	0.634	0.111	0.019	29.366
13	Production Revenue	2.117	1.364	1.489	10.138	3.119	4.092	7.041	-	0.815	0.130	0.017	30.322
14	Distribution Revenue	1.063	0.075	0.271	4.104	0.268	1.010	3.356	-	0.043	0.064	0.016	10.271
15	Total Rate Revenue	1.707	0.863	1.016	7.792	2.010	2.894	5.609	-	0.515	0.104	0.016	22.528
16	Billed Sales	1.759	1.105	1.182	7.882	5.802	6.028	8.014	18.761	0.791	0.127	0.016	51.467
17	Number Of Customers	0.074	0.001	0.004	0.074	0.002	0.005	0.056	0.000	0.000	0.000	0.000	0.217
18	Weighted Customer	3.005	0.071	0.361	4.140	0.125	0.303	3.065	0.004	0.019	0.021	0.011	11.124
		-	-	-	-	-	-	-	-	-	-	-	-
	*Calculated Allocation Schedules	-	-	-	-	-	-	-	-	-	-	-	-
19	4CP 75/0/25	1.720	0.923	1.048	7.973	1.985	2.811	5.554	14.351	0.618	0.095	0.013	37.089
20	Class Peak @ Voltage 2	2.277	-	1.070	8.684	-	4.908	7.871	-	-	0.118	0.020	24.949
21	Class Peak Voltage 1 Only	0.163	15.143	-	-	69.834	-	-	-	10.285	-	-	95.425
22	Class Peak Voltage 2 Only	1.574	-	16.464	-	-	75.532	-	-	-	1.817	-	95.387
23	Class Peak @ Voltage 1 excluding Voltage 2	2.191	0.995	-	8.705	4.588	-	7.891	-	0.676	-	0.020	25.065
24	Class Peak @ Voltage 3	2.323	-	-	9.318	-	-	8.447	-	-	-	0.022	20.109
25	Class Peak @ Voltage 4	-	-	-	-	-	-	-	-	-	-	-	-
26	Class Peak for Streetlighting	-	-	-	-	-	-	-	-	-	-	-	-
27	Class Peak @ Single Phase	-	-	-	-	-	-	-	-	-	-	-	-
28	Billed Sales - Primary	2.543	-	-	11.988	-	-	12.189	-	-	-	0.024	26.744
29	Customers - Residential	-	-	-	-	-	-	-	-	-	-	-	-
30	Customers - Commercial Secondary	-	-	-	-	-	-	-	-	-	-	-	-
31	Customers - Non-Primary	-	-	-	-	-	-	-	-	-	-	-	-
32	Customers - Non-Lighting	0.074	0.001	0.004	0.074	0.002	0.005	0.056	0.000	0.000	0.000	0.000	0.218
33	Customers - Commercial & Primary	0.613	0.010	0.035	0.610	0.016	0.042	0.465	0.000	0.002	0.003	0.002	1.798
34	Customer Count (CCC)	-	-	-	-	-	-	-	-	-	-	-	-
35	Customer Count (BCC)	1.168	0.019	0.066	1.162	0.030	0.080	0.886	0.001	0.004	0.006	0.004	3.426
36	PIS - HVD (Voltage 1)	2.276	0.048	0.953	8.725	0.220	4.371	7.909	-	0.032	0.105	0.020	24.659
37	PIS - HVD (Voltage 2)	1.945	-	1.687	7.157	-	7.739	6.487	-	-	0.186	0.017	25.218
38	PIS - HVD (Voltage 1) Substations	2.277	-	1.070	8.684	-	4.908	7.871	-	-	0.118	0.020	24.949
39	PIS - HVD (Voltage 2) Substations	2.151	-	3.774	7.182	-	17.314	6.510	-	-	0.417	0.017	37.365
40	PIS - OH LVD System	0.656	-	-	2.631	-	-	2.385	-	-	-	0.006	5.678
41	PIS - LVD Distribution	0.890	0.188	0.116	2.990	0.853	0.441	2.663	0.000	0.126	0.012	0.007	8.286
42	PIS- OH (LVD & HVD) Lines & Services	0.775	0.042	0.129	3.055	0.194	0.592	2.769	-	0.029	0.014	0.007	7.606
43	PIS- UG LVD Distribution	0.557	0.206	0.008	2.223	0.950	0.037	2.015	-	0.140	0.001	0.005	6.142
44	PIS- Total Distribution	1.051	0.164	0.297	3.637	0.746	1.285	3.256	0.000	0.110	0.032	0.009	10.587

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Total Electric	(c) Total Residential	(d) Total Commercial Secondary	(e) Total Lighting & Unmetered	(f) Total Primary	(g) Rate GSG
1	*Calculated Allocation Schedules						
2	PIS- Distribution Services	100.000	94.121	5.879	-	-	-
3	PIS- Streetlighting Equipment	100.000	-	-	100.000	-	-
4	PIS- Line Equipment	100.000	66.184	31.372	0.492	1.944	0.007
5	PIS- Meters	100.000	60.166	28.619	0.054	11.124	0.038
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000
7	Total PIS	100.000	58.568	25.294	1.671	14.248	0.218
8	Distribution Depreciation	100.000	64.799	24.619	2.708	7.763	0.111
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	100.000	35.783	16.962	0.266	45.401	1.588
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	100.000	50.502	23.939	0.375	24.694	0.491
11	PIS- LVD OH Lines & Services	100.000	68.843	26.036	0.392	4.711	0.018
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	100.000	-	-	-	95.425	4.575
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	100.000	52.165	24.727	0.388	22.394	0.327
14	CWIP	100.000	56.727	26.023	0.464	16.554	0.231
15	Rate Base- Total	100.000	57.991	25.492	1.422	14.883	0.211
16	Dist Op Expense (LVD) excl Sup & Eng	100.000	67.912	24.848	3.035	4.181	0.025
17	Dist Maint Expense (LVD) excl Sup & Eng	100.000	68.695	26.092	0.413	4.781	0.018
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.156	21.405	0.335	32.173	0.930
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.597	21.614	0.339	31.552	0.899
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.626	23.524	0.369	25.955	0.526
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.354	23.395	0.367	26.347	0.537
22	Total HVD Distribution O&M Expense	100.000	48.235	22.864	0.358	27.896	0.646
23	Total Distribution O&M Expense (excl. HVD)	100.000	68.541	25.773	1.077	4.590	0.019
24	Total Customer Accounts Expense (excl. Supv)	100.000	74.660	16.658	0.445	8.226	0.012
25	Total Customer Accounts & Service Expense	100.000	72.700	16.477	0.434	10.355	0.034
26	Pre Tax NOI	100.000	50.889	27.889	1.338	19.399	0.485
27	Depreciation & Amortization Expense	100.000	56.353	24.833	1.706	16.873	0.235
28	Non PSCR O&M Expense	100.000	63.838	24.084	0.813	11.142	0.124
29	Distribution Depreciation Expense	100.000	61.454	25.640	2.973	9.783	0.150
30	Gen/Comm/Int Depreciation Expense	100.000	60.406	23.254	0.740	15.464	0.136
31	Production Labor	100.000	41.641	20.709	0.237	37.089	0.323
32	Total Labor	100.000	60.406	23.254	0.740	15.464	0.136
33	50% O&M, 50% Net Plant	100.000	54.176	24.570	1.307	19.695	0.252
34	50/50 PIS & Labor	100.000	59.487	24.274	1.206	14.856	0.177

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate RS	(c) Total Residential	(d) Rate GS	(e) Rate GSD	(f) Total Commercial Secondary	(g) Rate GML	(h) - Rate UUL	(i) Rate GU	(j) Total Lighting & Unmetered
1	*Calculated Allocation Schedules									
2	PIS- Distribution Services	94.121	94.121	5.347	0.533	5.879	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	1.423	98.577	-	100.000
4	PIS- Line Equipment	66.184	66.184	19.321	12.052	31.372	0.055	0.222	0.214	0.492
5	PIS- Meters	60.166	60.166	23.310	5.309	28.619	0.054	-	-	0.054
6	PIS - General	100.000	100.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Total PIS	58.568	58.568	15.890	9.404	25.294	0.054	1.441	0.176	1.671
8	Distribution Depreciation	64.799	64.799	15.776	8.843	24.619	0.074	2.484	0.150	2.708
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	35.783	35.783	10.446	6.516	16.962	0.030	0.120	0.116	0.266
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	50.502	50.502	14.743	9.196	23.939	0.042	0.169	0.164	0.375
11	PIS- LVD OH Lines & Services	68.843	68.843	16.328	9.708	26.036	0.044	0.177	0.171	0.392
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	-	-	-	-	-	-	-	-	-
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	52.165	52.165	15.228	9.499	24.727	0.044	0.175	0.169	0.388
14	CWIP	56.727	56.727	16.021	10.002	26.023	0.035	0.230	0.199	0.464
15	Rate Base- Total	57.991	57.991	15.979	9.513	25.492	0.052	1.192	0.179	1.422
16	Dist Op Expense (LVD) excl Sup & Eng	67.912	67.912	15.488	9.359	24.848	0.080	2.785	0.170	3.035
17	Dist Maint Expense (LVD) excl Sup & Eng	68.695	68.695	16.426	9.666	26.092	0.045	0.199	0.169	0.413
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	45.156	45.156	13.182	8.223	21.405	0.038	0.151	0.146	0.335
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	45.597	45.597	13.311	8.303	21.614	0.038	0.153	0.148	0.339
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	49.626	49.626	14.487	9.037	23.524	0.041	0.166	0.161	0.369
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	49.354	49.354	14.408	8.987	23.395	0.041	0.166	0.160	0.367
22	Total HVD Distribution O&M Expense	48.235	48.235	14.081	8.783	22.864	0.040	0.162	0.156	0.358
23	Total Distribution O&M Expense (excl. HVD)	68.541	68.541	16.185	9.589	25.773	0.053	0.854	0.170	1.077
24	Total Customer Accounts Expense (excl. Supv)	74.660	74.660	12.502	4.156	16.658	0.026	0.326	0.093	0.445
25	Total Customer Accounts & Service Expense	72.700	72.700	12.275	4.201	16.477	0.025	0.310	0.098	0.434
26	Pre Tax NOI	50.889	50.889	17.954	9.935	27.889	0.036	1.112	0.190	1.338
27	Depreciation & Amortization Expense	56.353	56.353	15.651	9.183	24.833	0.049	1.476	0.181	1.706
28	Non PSCR O&M Expense	63.838	63.838	15.264	8.820	24.084	0.041	0.600	0.172	0.813
29	Distribution Depreciation Expense	61.454	61.454	16.620	9.020	25.640	0.080	2.745	0.148	2.973
30	Gen/Comm/Int Depreciation Expense	60.406	60.406	14.654	8.599	23.254	0.037	0.535	0.168	0.740
31	Production Labor	41.641	41.641	12.536	8.174	20.709	0.008	0.037	0.193	0.237
32	Total Labor	60.406	60.406	14.654	8.599	23.254	0.037	0.535	0.168	0.740
33	50% O&M, 50% Net Plant	54.176	54.176	15.302	9.269	24.570	0.048	1.072	0.186	1.307
34	50/50 PIS & Labor	59.487	59.487	15.272	9.002	24.274	0.046	0.988	0.172	1.206

*Calculated allocation schedules may vary between product

Projected 12-Month Period Ending April 30, 2027
U-21870 Large Load Proposals
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b) Rate GP	(c) Rate GPTU Vlt 1	(d) Rate GPTU Vlt 2	(e) Rate GPTU Vlt 3	(f) Rate GPD Vlt 1	(g) Rate GPD Vlt 2	(h) Rate GPD Vlt 3	(i) Rate LARGE LOAD	(i) Rate EIP Vlt 1	(j) Rate EIP Vlt 2	(k) Rate EIP Vlt 3	(l) Total Primary
1	*Calculated Allocation Schedules												
2	PIS- Distribution Services	-	-	-	-	-	-	-	-	-	-	-	-
3	PIS- Streetlighting Equipment	-	-	-	-	-	-	-	-	-	-	-	-
4	PIS- Line Equipment	0.225	-	-	0.901	-	-	0.817	-	-	-	0.002	1.944
5	PIS- Meters	3.005	0.071	0.361	4.140	0.125	0.303	3.065	0.004	0.019	0.021	0.011	11.124
6	PIS - General	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Total PIS	1.241	0.365	0.496	4.844	1.076	1.690	3.923	0.310	0.245	0.049	0.010	14.248
8	Distribution Depreciation	0.843	0.096	0.182	2.839	0.430	0.751	2.532	0.000	0.063	0.019	0.007	7.763
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	1.599	5.085	-	6.189	23.450	-	5.610	-	3.454	-	0.014	45.401
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	2.278	-	1.008	8.735	-	4.623	7.918	-	-	0.111	0.020	24.694
11	PIS- LVD OH Lines & Services	0.544	-	-	2.183	-	-	1.979	-	-	-	0.005	4.711
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	0.163	15.143	-	-	69.834	-	-	-	10.285	-	-	95.425
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	2.301	-	0.504	9.023	-	2.311	8.178	-	-	0.056	0.021	22.394
14	CWIP	1.296	0.446	0.591	5.613	1.074	1.845	4.367	0.955	0.299	0.057	0.010	16.554
15	Rate Base- Total	1.255	0.342	0.502	4.938	0.982	1.737	4.024	0.817	0.228	0.050	0.010	14.883
16	Dist Op Expense (LVD) excl Sup & Eng	0.382	0.011	(0.005)	1.911	0.061	0.043	1.766	(0.000)	0.009	0.000	0.004	4.181
17	Dist Maint Expense (LVD) excl Sup & Eng	0.573	0.001	0.004	2.203	0.002	0.004	1.989	0.000	0.000	0.000	0.005	4.781
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	2.017	2.005	0.463	7.810	9.244	2.124	7.080	-	1.361	0.051	0.018	32.173
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	2.037	1.860	0.485	7.887	8.576	2.224	7.149	-	1.263	0.054	0.018	31.552
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	2.265	-	1.282	8.584	-	5.882	7.780	-	-	0.142	0.020	25.955
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	2.261	-	1.367	8.537	-	6.273	7.738	-	-	0.151	0.020	26.347
22	Total HVD Distribution O&M Expense	2.194	0.561	1.097	8.343	2.585	5.033	7.562	-	0.381	0.121	0.019	27.896
23	Total Distribution O&M Expense (excl. HVD)	0.521	0.002	0.000	2.119	0.012	0.006	1.923	(0.000)	0.002	0.000	0.005	4.590
24	Total Customer Accounts Expense (excl. Supv)	0.649	0.312	0.368	2.845	0.726	1.047	2.049	0.000	0.186	0.038	0.006	8.226
25	Total Customer Accounts & Service Expense	0.686	0.343	0.398	3.003	0.987	1.286	2.299	1.093	0.212	0.041	0.006	10.355
26	Pre Tax NOI	1.730	0.730	1.020	7.694	1.180	2.726	5.463	(1.272)	(0.010)	0.118	0.021	19.399
27	Depreciation & Amortization Expense	1.442	0.523	0.649	5.781	1.301	1.930	4.394	0.431	0.349	0.061	0.011	16.873
28	Non PSCR O&M Expense	0.906	0.288	0.344	3.920	0.710	1.039	3.114	0.589	0.193	0.033	0.008	11.142
29	Distribution Depreciation Expense	1.113	0.140	0.264	3.435	0.623	1.049	3.032	0.000	0.092	0.027	0.008	9.783
30	Gen/Comm/Int Depreciation Expense	0.956	0.324	0.389	4.159	0.791	1.169	3.256	4.160	0.215	0.037	0.008	15.464
31	Production Labor	1.720	0.923	1.048	7.973	1.985	2.811	5.554	14.351	0.618	0.095	0.013	37.089
32	Total Labor	0.956	0.324	0.389	4.159	0.791	1.169	3.256	4.160	0.215	0.037	0.008	15.464
33	50% O&M, 50% Net Plant	1.331	0.470	0.607	5.429	1.343	2.018	4.298	3.803	0.322	0.061	0.011	19.695
34	50/50 PIS & Labor	1.098	0.344	0.442	4.501	0.934	1.430	3.590	2.235	0.230	0.043	0.009	14.856

*Calculated allocation schedules may vary between product

STATEOFMICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBIT

OF

JEFFREY P. DICKEY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
March/April Ice Storm Comprehensive Cost & Comparative Analysis Data
Service Restoration
($000)

Case No.: U-22070
Exhibit No.: A-85 (JPD-1)
Page: 1 of 1
Witness: JPDickey
Date: June 2026

	2/22/2023 Storm	3/28/2025 Storm	Variance 2025 to 2023	Notes
Storm Type:	Wind/Ice	Wind/Ice		
Declared Statewide Storm:	2/22/2023	3/29/2025 1pm		
Undeclared Statewide Storm:	3/3/2023	4/6/2025 10am		
Restoration Duration:	200.5 Hours	189 Hours	(12)	
Customers Restored in 48 Hrs	50%	83%	33%	
Resource Information:				
CE Crews	180	193	13	
Electric Service Workers	93	82	(11)	
CE FTE's	812	854	42	
Contractor Crews	444	636	192	
Contractor FTE's	1,776	3,180	1,404	
Forestry Crews	300	306	6	
Wire Down Resources	359	350	(9)	
Damage Assesment Teams	59	46	(13)	
Exempt FTE's	522	689	167	
Nonexempt FTE's	231	229	(2)	
Outage Information:				
No. Customers Out	435,707	383,876	(51,831)	
No. Interruptions/Outages	10,839	8,552	(2,287)	
No. Customer Minutes	849,543,096	574,381,636	(275,161,460)	
No. Wire Downs	11,157	7,156	(4,001)	
Overall Cost Information:				
Total Storm Cost (w/ Corp. Overheads)	$ 100,486,793	$ 155,989,050	55,502,257	
Total Storm Cost (w/o Corp. Overheads)	$ 88,934,812	$ 134,840,224	45,905,412	
O&M Cost	$ 62,964,690	$ 51,996,958	(10,967,732)	
Capital Cost (w/ Corp. Overheads)	$ 37,522,103	$ 103,992,092	66,469,989	
Capital Cost (w/o Corp. Overheads)	$ 25,970,122	$ 82,843,266	56,873,144	
Resource Costs:				
Total CE Labor *(includes Indirect Labor)*	$ 17,184,829	$ 24,246,251	7,061,422	
CE O&M	$ 11,637,195	$ 12,134,703	497,508	
CE Capital	$ 5,547,634	$ 12,111,548	6,563,914	
Total Contractor Costs	$ 51,264,797	$ 75,852,369	24,587,572	
Contractor O&M	$ 41,681,067	$ 27,511,719	(14,169,348)	
Contractor Capital	$ 9,583,730	$ 48,340,650	38,756,920	
Total Forestry Cost	$ 2,051,604	$ 4,970,126	2,918,522	
Forestry O&M	$ 1,286,933	$ 3,219,910	1,932,977	
Forestry Capital	$ 764,672	$ 1,750,216	985,545	
Material Information:				
Quantity of poles	1,045	1,810	765	
Total cost of poles	$ 577,024	$ 1,250,130	673,106	
Unit cost per pole	$ 552	$ 691	139	
Quantity of transformers	410	636	226	
Total cost of transformers	$ 556,494	$ 2,295,714	1,739,220	
Unit cost per transformers	$ 1,357	$ 3,610	2,252	
Quantity of crossarms	1,917	3,678	1,761	
Total cost of crossarms	$ 266,853	$ 460,795	193,942	
Unit cost per crossarms	$ 139	$ 125	(14)	
Quantity of pole top capital	7,531	15,481	7,950	
Total cost of pole top capital	$ 182,170	$ 470,074	287,904	
Unit cost of pole top capital	$ 24	$ 30	6	
Unit Cost Requirements:				
Total unit cost for CE Crews	$ 95,604	$ 125,628	$ 30,024	
O&M unit cost for CE Crews	$ 64,741	$ 62,874	$ (1,867)	
Capital unit cost for CE crews	$ 30,863	$ 62,754	$ 31,891	
Total unit cost for CE FTE	$ 18,989	$ 25,904	$ 6,915	
O&M unit cost for CE FTE	$ 12,859	$ 12,964	$ 106	
Capital unit cost for CE FTE	$ 6,130	$ 12,940	$ 6,810	
Total unit cost for Contractor crews	$ 115,461	$ 119,265	$ 3,803	
O&M unit cost for Contractor crews	$ 93,876	$ 43,257	$ (50,619)	
Capital unit cost for Contractor Crews	$ 21,585	$ 76,007	$ 54,422	
Total unit cost for Contractor FTE	$ 28,865	$ 23,853	$ (5,012)	
O&M unit cost for Contractor FTE	$ 23,469	$ 8,651	$ (14,818)	
Capital unit cost for Contractor FTE	$ 5,396	$ 15,201	$ 9,805	
Total unit cost per crew (CE & Contractor)	$ 109,739	$ 120,746	$ 11,007	
O&M unit cost per crew (CE & Contractor)	$ 85,480	$ 47,824	$ (37,656)	
Capital unit cost per crew (CE & Contractor)	$ 24,259	$ 72,922	$ 48,663	
Total cost per support worker	$ 2,524	$ 3,142	$ 618	
O&M cost per support worker	$ 1,585	$ 2,032	$ 447	
Capital cost per support worker	$ 939	$ 1,110	$ 171	
Total cost per case of trouble	$ 9,007	$ 21,798	$ 12,792	Defined as total cost per wire down
Wire Down Response Times (minutes)	21,615,719	4,318,181	$ (17,297,538)	
Average Wiredown Duration (hours)	32.3	10.1	$ (22)	
Total cost per customer interruption	$ 9,271	$ 18,240	$ 8,969	
Total cost per customer minute of interruption	$ 0.12	$ 0.27	$ 0.15	

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

EMILY M. DUKE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Schedule: B-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Electric Distribution
($000)

Case No.: U-22070
Exhibit No.: A-12 (EMD-1)
Schedule: B-5.6
Page: 1 of 2
Witness: EMDuke
Date: June 2026

Line No.	(a) Program / Sub-Program	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Period 12 Mos Ended 12/31/2026	(d) Projected Bridge Period 4 Mos Ending 4/30/2027	(e) Projected Bridge Period 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
1	Lines New Business - LVD	$ 114,568	$ 117,890	$ 37,626	$ 155,516	$ 121,618
2	Lines Strategic Customers - HVD	40,821	39,549	3,456	43,005	48,064
3	Distribution Transformer Purchases	152,452	144,655	43,063	187,718	138,661
4	Metro New Business	6,209	6,584	2,640	9,223	7,737
5	**New Business**	**314,050**	**308,677**	**86,785**	**395,462**	**316,079**
6	Lines Failures - LVD	266,151	179,495	43,635	223,131	134,513
7	Lines & Subs Failures - HVD	13,380	8,324	3,333	11,657	10,333
8	Substations Failures - LVD	11,268	11,050	2,150	13,200	11,000
9	Distribution Meter Purchases	27,380	22,525	6,054	28,580	16,843
10	Metro Failures	(53)	416	117	532	350
11	**Demand Failures**	**318,126**	**221,811**	**55,290**	**277,100**	**173,040**
12	Lines Relocations - LVD	88,913	128,106	40,003	168,109	131,401
13	Lines Relocations - HVD	610	898	300	1,198	899
14	Metro Relocations	14,353	19,400	6,802	26,201	18,270
15	**Asset Relocations**	**103,876**	**148,405**	**47,104**	**195,509**	**150,570**
16	Lines Reliability - LVD	110,025	193,837	130,424	324,261	250,625
17	Lines Reliability - HVD	101,058	92,967	42,718	135,685	108,778
18	Substations Reliability - LVD	43,773	41,653	24,011	65,664	42,880
19	Substations Reliability - HVD	23,161	15,080	10,649	25,729	46,180
20	Grid Capabilities - Automation	20,179	11,510	3,673	15,183	8,260
21	System Protection	5,244	4,462	1,478	5,939	4,672
22	Repetitive Outages - LVD	12,903	23,080	10,135	33,215	27,493
23	Metro Reliability	4,629	3,998	1,333	5,330	4,131
24	Transformer Bank Replacement and Substation Rebuild	22,285	15,371	11,234	26,605	37,155
25	Substations Rehabilitation - LVD	22,174	25,701	5,299	31,000	31,328
26	Lines Rehabilitation - LVD	16,847	20,031	13,774	33,805	22,977
27	Metro Rehabilitation	4,512	2,953	(0)	2,953	5,495
28	Grid Storage	(86)	-	-	-	-
29	Grid Capabilities - Advanced Tech	-	-	-	-	-
30	Resiliency	41,767	20,143	34,887	55,030	78,751
31	**Reliability**	**428,469**	**470,784**	**289,616**	**760,400**	**668,725**
32	Lines Capacity - LVD	17,876	15,134	24,726	39,861	53,485
33	Lines & Subs Capacity - HVD	20,006	20,286	21,618	41,904	34,956
34	Substations Capacity - LVD	33,612	10,761	8,124	18,885	22,399
35	Transformers Capacity - LVD	-	-	-	-	-
36	Lines New Business Capacity - LVD	32,679	26,785	13,371	40,156	30,339
37	Conservation Voltage Reduction	5,159	2,459	1,409	3,868	2,429
38	Lines Solar Interconnections - LVD	-	-	-	-	-
39	Subs Solar Interconnections - HVD	0	-	-	-	-
40	**Capacity**	**109,331**	**75,426**	**69,247**	**144,673**	**143,608**
41	Computers & Equipment	(65)	75	25	100	75
42	Tools	5,796	8,177	1,475	9,652	8,277
43	System Control Projects	57	6	73	79	196
44	**Electric Other**	**5,788**	**8,258**	**1,573**	**9,831**	**8,548**
45	**Total Electric Distribution**	**$ 1,279,640**	**$ 1,233,360**	**$ 549,615**	**$ 1,782,975**	**$ 1,460,571**

Schedule: B-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Electric Distribution
($000)

Case No.: U-22070
Exhibit No.: A-12 (EMD-1)
Schedule: B-5.6
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Witness: EMDuke
Date: June 2026

Line No.	(a) Program / Sub-Program	(g) Historical Year 12 Mos Ended 12/31/2025	(i) 4 Mos Ending 4/30/2026	(j) Projected 12 Mos Ending 4/30/2027	(k) 12 Mos Ending 4/30/2028	(l) 28 Mos Ending 4/30/2028
46	Lines New Business - LVD	$ 114,568	$ 34,600	$ 120,916	$ 121,618	$ 277,133
47	Lines Strategic Customers - HVD	40,821	9,183	33,822	48,064	91,069
48	Distribution Transformer Purchases	152,452	24,141	163,577	138,661	326,379
49	Metro New Business	6,209	2,098	7,125	7,737	16,960
50	**New Business**	**314,050**	**70,021**	**325,441**	**316,079**	**711,541**
51	Lines Failures - LVD	266,151	46,434	176,697	134,513	357,644
52	Lines & Subs Failures - HVD	13,380	2,217	9,441	10,333	21,991
53	Substations Failures - LVD	11,268	3,717	9,483	11,000	24,200
54	Distribution Meter Purchases	27,380	8,629	19,950	16,843	45,423
55	Metro Failures	(53)	139	394	350	882
56	**Demand Failures**	**318,126**	**61,135**	**215,965**	**173,040**	**450,140**
57	Lines Relocations - LVD	88,913	30,492	137,618	131,401	299,511
58	Lines Relocations - HVD	610	299	899	899	2,097
59	Metro Relocations	14,353	8,676	17,526	18,270	44,471
60	**Asset Relocations**	**103,876**	**39,467**	**156,042**	**150,570**	**346,079**
61	Lines Reliability - LVD	110,025	73,069	251,192	250,625	574,886
62	Lines Reliability - HVD	101,058	40,801	94,884	108,778	244,463
63	Substations Reliability - LVD	43,773	20,978	44,686	42,880	108,544
64	Substations Reliability - HVD	23,161	11,349	14,380	46,180	71,909
65	Grid Capabilities - Automation	20,179	1,912	13,271	8,260	23,443
66	System Protection	5,244	3,059	2,880	4,672	10,611
67	Repetitive Outages - LVD	12,903	7,102	26,113	27,493	60,708
68	Metro Reliability	4,629	1,333	3,998	4,131	9,462
69	Transformer Bank Replacement and Substation Rebuild	22,285	5,837	20,768	37,155	63,760
70	Substations Rehabilitation - LVD	22,174	9,003	21,997	31,328	62,328
71	Lines Rehabilitation - LVD	16,847	6,826	26,980	22,977	56,782
72	Metro Rehabilitation	4,512	984	1,968	5,495	8,448
73	Grid Storage	(86)	-	-	-	-
74	Resiliency	41,767	4,250	50,780	78,751	133,781
75	**Reliability**	**428,469**	**186,503**	**573,897**	**668,725**	**1,429,125**
76	Lines Capacity - LVD	17,876	8,834	31,027	53,485	93,346
77	Lines & Subs Capacity - HVD	20,006	9,596	32,308	34,956	76,859
78	Substations Capacity - LVD	33,612	9,433	9,451	22,399	41,284
79	Lines New Business Capacity - LVD	32,679	6,046	34,110	30,339	70,495
80	Conservation Voltage Reduction	5,159	708	3,160	2,429	6,297
81	Subs Solar Interconnections - HVD	0	-	-	-	-
82	**Capacity**	**109,331**	**34,617**	**110,056**	**143,608**	**288,281**
83	Computers & Equipment	(65)	25	75	75	175
84	Tools	5,796	1,462	8,190	8,277	17,929
85	System Control Projects	57	2	77	196	275
86	**Electric Other**	**5,788**	**1,489**	**8,342**	**8,548**	**18,380**
87	**Total Electric Distribution**	**$ 1,279,640**	**$ 393,232**	**$ 1,389,742**	**$ 1,460,571**	**$ 3,243,546**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Electric Distribution
($000)

Case No.: U-22070
Exhibit No.: A-86 (EMD-2)
Page: 1 of 10
Witness: EMDuke
Date: June 2026

Line No	Description	(a)	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Year 12 Mos Ending 12/31/2026	(d) Projected Bridge Year 4 Mos Ending 4/30/2027	(e) Projected Bridge Year 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
1	**Lines New Business - LVD**		**$ 114,568**	**$ 117,890**	**$ 37,626**	**$ 155,516**	**$ 121,618**
2	Labor		39,120	40,255	12,848	53,103	41,528
3	Capitalized E&S		21,412	22,033	7,032	29,065	22,729
4	Materials		23,900	24,593	7,849	32,442	25,371
5	Contractor		14,770	15,199	4,851	20,049	15,679
6	Non-Labor Overhead		9,665	9,945	3,174	13,119	10,260
7	Non-Labor Other		5,700	5,866	1,872	7,738	6,051
8	Contingency		-	-	-	-	-
9	**Lines Strategic Customers - HVD**		**40,821**	**39,549**	**3,456**	**43,005**	**48,064**
10	Labor		2,244	2,174	190	2,364	2,642
10	Capitalized E&S		9,091	8,808	770	9,578	10,704
11	Materials		25,874	25,067	2,191	27,258	30,465
11	Contractor		7,609	7,371	644	8,016	8,958
12	Non-Labor Overhead		238	231	20	251	280
12	Non-Labor Other		(4,235)	(4,103)	(359)	(4,461)	(4,986)
13	Contingency		-	-	-	-	-
14	**Distribution Transformer Purchases**		**152,452**	**144,655**	**43,063**	**187,718**	**138,661**
15	Labor		4,557	4,324	1,287	5,611	4,145
15	Capitalized E&S		30,053	28,516	8,489	37,005	27,334
16	Materials		108,282	102,743	30,587	133,330	98,486
16	Contractor		-	-	-	-	-
17	Non-Labor Overhead		-	-	-	-	-
17	Non-Labor Other		9,561	9,072	2,701	11,772	8,696
18	Contingency		-	-	-	-	-
19	**Metro New Business**		**6,209**	**6,584**	**2,640**	**9,223**	**7,737**
20	Labor		264	280	112	392	329
20	Capitalized E&S		1,205	1,278	512	1,790	1,502
21	Materials		978	1,037	416	1,452	1,218
21	Contractor		3,187	3,379	1,355	4,734	3,971
22	Non-Labor Overhead		46	49	20	69	58
22	Non-Labor Other		529	561	225	786	660
23	Contingency		-	-	-	-	-
24	**Lines Failures - LVD**		**266,151**	**179,495**	**43,635**	**223,131**	**134,513**
25	Labor		59,462	40,102	9,749	49,851	30,052
25	Capitalized E&S		45,004	30,351	7,378	37,729	22,745
26	Materials		23,039	15,538	3,777	19,315	11,644
26	Contractor		69,846	47,105	11,451	58,556	35,300
27	Non-Labor Overhead		11,004	7,421	1,804	9,225	5,561
27	Non-Labor Other		57,797	38,979	9,476	48,455	29,210
28	Contingency		-	-	-	-	-
29	**Lines & Subs Failures - HVD**		**13,380**	**8,324**	**3,333**	**11,657**	**10,333**
30	Labor		732	455	182	637	565
30	Capitalized E&S		2,494	1,552	621	2,173	1,926
31	Materials		3,124	1,943	778	2,722	2,412
31	Contractor		6,192	3,852	1,543	5,395	4,782
32	Non-Labor Overhead		130	81	32	113	100
32	Non-Labor Other		708	441	176	617	547
33	Contingency		-	-	-	-	-
34	**Substations Failures - LVD**		**11,268**	**11,050**	**2,150**	**13,200**	**11,000**
35	Labor		1,331	1,305	254	1,559	1,299
35	Capitalized E&S		1,972	1,934	376	2,310	1,925
36	Materials		5,376	5,272	1,026	6,298	5,248
36	Contractor		1,528	1,498	292	1,790	1,491
37	Non-Labor Overhead		272	267	52	319	265
37	Non-Labor Other		790	774	151	925	771
38	Contingency		-	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Electric Distribution
($000)

Case No.: U-22070
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Witness: EMDuke
Date: June 2026

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Year 12 Mos Ending 12/31/2026	(d) Projected Bridge Year 4 Mos Ending 4/30/2027	(e) Projected Bridge Year 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
39	**Distribution Meter Purchases**	**27,380**	**22,525**	**6,054**	**28,580**	**16,843**
40	Labor	7,252	5,966	1,604	7,570	4,461
41	Capitalized E&S	4,474	3,681	989	4,670	2,752
42	Materials	12,646	10,404	2,796	13,200	7,780
43	Contractor	165	135	36	172	101
44	Non-Labor Overhead	43	35	9	45	26
45	Non-Labor Other	2,800	2,304	619	2,923	1,723
46	Contingency	-	-	-	-	-
47	**Metro Failures**	**(53)**	**416**	**117**	**532**	**350**
48	Labor	(5)	41	11	52	34
49	Capitalized E&S	(8)	60	17	77	51
50	Materials	(1)	5	2	7	5
51	Contractor	-	-	-	-	-
52	Non-Labor Overhead	-	-	-	-	-
53	Non-Labor Other	(40)	309	87	396	260
54	Contingency	-	-	-	-	-
55	**Lines Relocations - LVD**	**88,913**	**128,106**	**40,003**	**168,109**	**131,401**
56	Labor	20,266	29,199	9,118	38,317	29,950
57	Capitalized E&S	17,782	25,620	8,000	33,620	26,279
58	Materials	14,550	20,964	6,546	27,511	21,503
59	Contractor	43,452	62,606	19,550	82,156	64,216
60	Non-Labor Overhead	5,100	7,347	2,294	9,642	7,536
61	Non-Labor Other	(12,236)	(17,630)	(5,505)	(23,136)	(18,084)
62	Contingency	-	-	-	-	-
63	**Lines Relocations - HVD**	**610**	**898**	**300**	**1,198**	**899**
64	Labor	44	65	22	87	65
65	Capitalized E&S	423	624	208	832	624
66	Materials	519	765	255	1,020	766
67	Contractor	1,239	1,825	609	2,434	1,827
68	Non-Labor Overhead	2	3	1	4	3
69	Non-Labor Other	(1,618)	(2,384)	(795)	(3,179)	(2,386)
70	Contingency	-	-	-	-	-
71	**Metro Relocations**	**14,353**	**19,400**	**6,802**	**26,201**	**18,270**
72	Labor	500	676	237	913	636
73	Capitalized E&S	3,100	4,190	1,469	5,659	3,946
74	Materials	2,385	3,224	1,130	4,354	3,036
75	Contractor	10,395	14,050	4,926	18,976	13,232
76	Non-Labor Overhead	68	91	32	123	86
77	Non-Labor Other	(2,095)	(2,831)	(993)	(3,824)	(2,666)
78	Contingency	-	-	-	-	-
79	**Lines Reliability - LVD**	**110,025**	**193,837**	**130,424**	**324,261**	**250,625**
80	Labor	20,942	36,895	24,825	61,720	47,704
81	Capitalized E&S	15,010	26,444	17,793	44,238	34,192
82	Materials	15,194	26,769	18,012	44,781	34,611
83	Contractor	33,901	59,725	40,187	99,912	77,223
84	Non-Labor Overhead	4,795	8,448	5,684	14,132	10,923
85	Non-Labor Other	20,182	35,555	23,924	59,479	45,972
86	Contingency	-	-	-	-	-
87	**Lines Reliability - HVD**	**101,058**	**92,967**	**42,718**	**135,685**	**108,778**
88	Labor	1,899	1,747	803	2,550	2,044
89	Capitalized E&S	16,219	14,921	6,856	21,776	17,458
90	Materials	22,941	21,104	9,697	30,802	24,694
91	Contractor	52,626	48,413	22,245	70,658	56,646
92	Non-Labor Overhead	209	192	88	280	225
93	Non-Labor Other	7,164	6,590	3,028	9,618	7,711
94	Contingency	-	-	-	-	-

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Consumers Energy Company
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($000)

Case No.: U-22070
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Witness: EMDuke
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2025	12 Mos Ending 12/31/2026	4 Mos Ending 4/30/2027	16 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028
95	**Substations Reliability - LVD**	**43,773**	**41,653**	**24,011**	**65,664**	**42,880**
96	Labor	1,200	1,142	658	1,800	1,175
97	Capitalized E&S	5,704	5,428	3,129	8,557	5,588
98	Materials	23,980	22,819	13,154	35,973	23,491
99	Contractor	10,380	9,878	5,694	15,572	10,169
100	Non-Labor Overhead	158	150	87	237	155
101	Non-Labor Other	2,351	2,237	1,289	3,526	2,303
102	Contingency	-	-	-	-	-
103	**Substations Reliability - HVD**	**23,161**	**15,080**	**10,649**	**25,729**	**46,180**
104	Labor	2,328	1,516	1,071	2,587	4,643
104	Capitalized E&S	3,478	2,264	1,599	3,863	6,934
105	Materials	8,201	5,340	3,771	9,111	16,353
105	Contractor	7,341	4,780	3,376	8,156	14,638
106	Non-Labor Overhead	332	216	152	368	661
106	Non-Labor Other	1,480	964	681	1,644	2,951
107	Contingency	-	-	-	-	-
108	**Grid Capabilities - Automation**	**20,179**	**11,510**	**3,673**	**15,183**	**8,260**
109	Labor	611	349	111	460	250
109	Capitalized E&S	1,954	1,115	356	1,470	800
110	Materials	6,094	3,476	1,109	4,586	2,495
110	Contractor	5,443	3,105	991	4,096	2,228
111	Non-Labor Overhead	7	4	1	5	3
111	Non-Labor Other	6,070	3,462	1,105	4,567	2,484
112	Contingency	-	-	-	-	-
113	**System Protection**	**5,244**	**4,462**	**1,478**	**5,939**	**4,672**
114	Labor	710	604	200	805	633
114	Capitalized E&S	863	734	243	977	769
115	Materials	1,513	1,288	426	1,714	1,348
115	Contractor	1,683	1,432	474	1,906	1,500
116	Non-Labor Overhead	45	38	13	51	40
116	Non-Labor Other	429	365	121	486	382
117	Contingency	-	-	-	-	-
118	**Repetitive Outages - LVD**	**12,903**	**23,080**	**10,135**	**33,215**	**27,493**
119	Labor	2,148	3,843	1,688	5,530	4,578
119	Capitalized E&S	1,954	3,495	1,535	5,030	4,163
120	Materials	2,384	4,265	1,873	6,137	5,080
120	Contractor	4,173	7,464	3,278	10,742	8,891
121	Non-Labor Overhead	515	921	405	1,326	1,098
121	Non-Labor Other	1,729	3,092	1,358	4,450	3,683
122	Contingency	-	-	-	-	-
123	**Metro Reliability**	**4,629**	**3,998**	**1,333**	**5,330**	**4,131**
124	Labor	168	145	48	193	150
124	Capitalized E&S	858	741	247	988	766
125	Materials	953	823	274	1,098	851
125	Contractor	2,249	1,942	647	2,590	2,007
126	Non-Labor Overhead	27	24	8	31	24
126	Non-Labor Other	374	323	108	430	333
127	Contingency	-	-	-	-	-
128	**Transformer Bank Replacement and Substation Rebuild**	**22,285**	**15,371**	**11,234**	**26,605**	**37,155**
129	Labor	841	580	424	1,003	1,401
129	Capitalized E&S	2,888	1,992	1,456	3,447	4,814
130	Materials	12,121	8,360	6,110	14,470	20,208
130	Contractor	4,477	3,088	2,257	5,345	7,465
131	Non-Labor Overhead	80	55	40	95	133
131	Non-Labor Other	1,879	1,296	947	2,244	3,134
132	Contingency	-	-	-	-	-

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Line No	Description	(a)	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Year 12 Mos Ending 12/31/2026	(d) Projected Bridge Year 4 Mos Ending 4/30/2027	(e) Projected Bridge Year 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
133	**Substations Rehabilitation - LVD**		**22,174**	**25,701**	**5,299**	**31,000**	**31,328**
134	Labor		1,302	1,509	311	1,820	1,839
135	Capitalized E&S		3,687	4,274	881	5,155	5,210
136	Materials		11,556	13,394	2,762	16,156	16,326
137	Contractor		4,172	4,836	997	5,833	5,895
138	Non-Labor Overhead		202	234	48	282	285
139	Non-Labor Other		1,255	1,454	300	1,754	1,773
140	Contingency		-	-	-	-	-
141	**Lines Rehabilitation - LVD**		**16,847**	**20,031**	**13,774**	**33,805**	**22,977**
142	Labor		3,191	3,794	2,609	6,403	4,352
142	Capitalized E&S		2,811	3,343	2,299	5,641	3,834
143	Materials		4,760	5,659	3,892	9,551	6,492
143	Contractor		3,269	3,887	2,673	6,561	4,459
144	Non-Labor Overhead		793	943	649	1,592	1,082
144	Non-Labor Other		2,022	2,404	1,653	4,057	2,758
145	Contingency		-	-	-	-	-
146	**Metro Rehabilitation**		**4,512**	**2,953**	**(0)**	**2,953**	**5,495**
147	Labor		162	106	(0)	106	198
147	Capitalized E&S		768	503	(0)	503	936
148	Materials		971	636	(0)	636	1,183
148	Contractor		2,278	1,491	(0)	1,491	2,775
149	Non-Labor Overhead		23	15	(0)	15	28
149	Non-Labor Other		308	202	(0)	202	375
150	Contingency		-	-	-	-	-
151	**Grid Storage**		**(86)**	**-**	**-**	**-**	**-**
152	Labor		19	-	-	-	-
152	Capitalized E&S		-	-	-	-	-
153	Materials		0	-	-	-	-
153	Contractor		53	-	-	-	-
154	Non-Labor Overhead		0	-	-	-	-
154	Non-Labor Other		(159)	-	-	-	-
155	Contingency		-	-	-	-	-
156	**Resiliency**		**41,767**	**20,143**	**34,887**	**55,030**	**78,751**
157	Labor		7,845	3,783	6,553	10,336	14,792
157	Capitalized E&S		6,637	3,201	5,544	8,745	12,514
158	Materials		13,521	6,521	11,294	17,815	25,494
158	Contractor		6,947	3,350	5,803	9,154	13,099
159	Non-Labor Overhead		1,976	953	1,650	2,603	3,725
159	Non-Labor Other		4,841	2,335	4,043	6,378	9,127
160	Contingency		-	-	-	-	-
161	**Lines Capacity - LVD**		**17,876**	**15,134**	**24,726**	**39,861**	**53,485**
162	Labor		3,877	3,282	5,363	8,645	11,600
163	Capitalized E&S		2,696	2,283	3,729	6,012	8,067
164	Materials		3,621	3,066	5,009	8,074	10,834
165	Contractor		4,200	3,556	5,810	9,365	12,567
166	Non-Labor Overhead		979	829	1,355	2,184	2,931
167	Non-Labor Other		2,503	2,119	3,462	5,581	7,488
168	Contingency		-	-	-	-	-
169	**Lines & Subs Capacity - HVD**		**20,006**	**20,286**	**21,618**	**41,904**	**34,956**
170	Labor		658	667	711	1,378	1,149
171	Capitalized E&S		4,707	4,773	5,086	9,859	8,224
172	Materials		6,589	6,681	7,120	13,800	11,512
173	Contractor		14,813	15,021	16,007	31,027	25,883
174	Non-Labor Overhead		102	104	111	214	179
175	Non-Labor Other		(6,863)	(6,959)	(7,416)	(14,375)	(11,991)
176	Contingency		-	-	-	-	-

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Line No	Description	(a)	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Year 12 Mos Ending 12/31/2026	(d) Projected Bridge Year 4 Mos Ending 4/30/2027	(e) Projected Bridge Year 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
177	**Substations Capacity - LVD**		**33,612**	**10,761**	**8,124**	**18,885**	**22,399**
178	Labor		1,688	540	408	949	1,125
179	Capitalized E&S		5,885	1,884	1,422	3,307	3,922
180	Materials		15,110	4,837	3,652	8,490	10,070
181	Contractor		9,456	3,027	2,286	5,313	6,302
182	Non-Labor Overhead		188	60	46	106	126
183	Non-Labor Other		1,283	411	310	721	855
184	Contingency		-	-	-	-	-
185	**Lines New Business Capacity - LVD**		**32,679**	**26,785**	**13,371**	**40,156**	**30,339**
186	Labor		6,977	5,719	2,855	8,573	6,477
187	Capitalized E&S		5,505	4,512	2,252	6,764	5,111
188	Materials		5,453	4,469	2,231	6,700	5,062
189	Contractor		8,620	7,065	3,527	10,592	8,003
190	Non-Labor Overhead		1,783	1,462	730	2,191	1,655
191	Non-Labor Other		4,341	3,558	1,776	5,335	4,030
192	Contingency		-	-	-	-	-
193	**Conservation Voltage Reduction**		**5,159**	**2,459**	**1,409**	**3,868**	**2,429**
194	Labor		772	368	211	579	364
195	Capitalized E&S		694	331	190	520	327
196	Materials		347	166	95	260	164
197	Contractor		2,386	1,138	652	1,789	1,124
198	Non-Labor Overhead		191	91	52	143	90
199	Non-Labor Other		768	366	210	576	362
200	Contingency		-	-	-	-	-
201	**Subs Solar Interconnections - HVD**		**0**	**-**	**-**	**-**	**-**
202	Labor		(0)	-	-	-	-
203	Capitalized E&S		0	-	-	-	-
204	Materials		(0)	-	-	-	-
205	Contractor		0	-	-	-	-
206	Non-Labor Overhead		-	-	-	-	-
207	Non-Labor Other		0	-	-	-	-
208	Contingency		-	-	-	-	-
209	**Computers & Equipment**		**(65)**	**75**	**25**	**100**	**75**
210	Labor		-	-	-	-	-
211	Capitalized E&S		-	-	-	-	-
212	Materials		-	-	-	-	-
213	Contractor		(64)	74	25	99	74
214	Non-Labor Overhead		-	-	-	-	-
215	Non-Labor Other		(1)	1	0	1	1
216	Contingency		-	-	-	-	-
217	**Tools**		**5,796**	**8,177**	**1,475**	**9,652**	**8,277**
218	Labor		0	0	0	0	0
219	Capitalized E&S		-	-	-	-	-
220	Materials		5,795	8,175	1,475	9,650	8,276
221	Contractor		1	1	0	2	1
222	Non-Labor Overhead		0	0	0	0	0
223	Non-Labor Other		0	0	0	0	0
224	Contingency		-	-	-	-	-
225	**System Control Projects**		**57**	**6**	**73**	**79**	**196**
226	Labor		5	1	6	7	16
227	Capitalized E&S		(2)	(0)	(3)	(3)	(8)
228	Materials		9	1	12	13	31
229	Contractor		17	2	22	24	60
230	Non-Labor Overhead		-	-	-	-	-
231	Non-Labor Other		28	3	36	39	97
232	Contingency		-	-	-	-	-
233	**Total Electric Distribution**		**$ 1,279,640**	**$ 1,233,360**	**$ 549,615**	**$ 1,782,975**	**$ 1,460,571**
234	Labor		193,111	191,432	84,467	275,899	220,198
235	Capitalized E&S		219,318	210,881	90,476	301,357	246,137
236	Materials		381,788	359,405	149,319	508,724	432,508
237	Contractor		336,807	340,297	162,206	502,503	410,566
238	Non-Labor Overhead		38,973	40,210	18,557	58,767	47,538
239	Non-Labor Other		109,644	91,135	44,590	135,725	103,624
240	Contingency		-	-	-	-	-

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Line No	Description	(a)	(b) Historical Year 12 Mos Ended 12/31/2025	(c) 4 Mos Ending 4/30/2026	(d) 12 Mos Ending 4/30/2027	(e) Projected 12 Mos Ending 4/30/2028	(f) 28 Mos Ending 4/30/2028
241	**Lines New Business - LVD**		**114,568**	**34,600**	**120,916**	**121,618**	**277,133**
242	Labor		39,120	11,815	41,288	41,528	94,630
243	Capitalized E&S		21,412	6,466	22,598	22,729	51,794
244	Materials		23,900	7,218	25,224	25,371	57,813
245	Contractor		14,770	4,461	15,589	15,679	35,729
246	Non-Labor Overhead		9,665	2,919	10,201	10,260	23,379
247	Non-Labor Other		5,700	1,722	6,016	6,051	13,789
248	Contingency		-	-	-	-	-
249	**Lines Strategic Customers - HVD**		**40,821**	**9,183**	**33,822**	**48,064**	**91,069**
250	Labor		2,244	505	1,859	2,642	5,006
251	Capitalized E&S		9,091	2,045	7,532	10,704	20,282
252	Materials		25,874	5,820	21,437	30,465	57,722
253	Contractor		7,609	1,712	6,304	8,958	16,974
254	Non-Labor Overhead		238	54	197	280	531
255	Non-Labor Other		(4,235)	(953)	(3,508)	(4,986)	(9,447)
256	Contingency		-	-	-	-	-
257	**Distribution Transformer Purchases**		**152,452**	**24,141**	**163,577**	**138,661**	**326,379**
258	Labor		4,557	722	4,890	4,145	9,756
259	Capitalized E&S		30,053	4,759	32,246	27,334	64,339
260	Materials		108,282	17,146	116,184	98,486	231,816
261	Contractor		-	-	-	-	-
262	Non-Labor Overhead		-	-	-	-	-
263	Non-Labor Other		9,561	1,514	10,258	8,696	20,468
264	Contingency		-	-	-	-	-
265	**Metro New Business**		**6,209**	**2,098**	**7,125**	**7,737**	**16,960**
266	Labor		264	89	303	329	721
267	Capitalized E&S		1,205	407	1,383	1,502	3,292
268	Materials		978	330	1,122	1,218	2,670
269	Contractor		3,187	1,077	3,657	3,971	8,705
270	Non-Labor Overhead		46	16	53	58	126
271	Non-Labor Other		529	179	607	660	1,446
272	Contingency		-	-	-	-	-
273	**Lines Failures - LVD**		**266,151**	**46,434**	**176,697**	**134,513**	**357,644**
274	Labor		59,462	10,374	39,477	30,052	79,903
275	Capitalized E&S		45,004	7,851	29,878	22,745	60,474
276	Materials		23,039	4,019	15,296	11,644	30,959
277	Contractor		69,846	12,186	46,371	35,300	93,856
278	Non-Labor Overhead		11,004	1,920	7,305	5,561	14,787
279	Non-Labor Other		57,797	10,083	38,371	29,210	77,665
280	Contingency		-	-	-	-	-
281	**Lines & Subs Failures - HVD**		**13,380**	**2,217**	**9,441**	**10,333**	**21,991**
282	Labor		732	121	516	565	1,202
283	Capitalized E&S		2,494	413	1,760	1,926	4,100
284	Materials		3,124	518	2,204	2,412	5,134
285	Contractor		6,192	1,026	4,369	4,782	10,177
286	Non-Labor Overhead		130	22	92	100	214
287	Non-Labor Other		708	117	500	547	1,164
288	Contingency		-	-	-	-	-
289	**Substations Failures - LVD**		**11,268**	**3,717**	**9,483**	**11,000**	**24,200**
290	Labor		1,331	439	1,120	1,299	2,859
291	Capitalized E&S		1,972	650	1,659	1,925	4,235
292	Materials		5,376	1,773	4,525	5,248	11,546
293	Contractor		1,528	504	1,286	1,491	3,281
294	Non-Labor Overhead		272	90	229	265	584
295	Non-Labor Other		790	260	664	771	1,696
296	Contingency		-	-	-	-	-
297	**Distribution Meter Purchases**		**27,380**	**8,629**	**19,950**	**16,843**	**45,423**
298	Labor		7,252	2,286	5,284	4,461	12,031
299	Capitalized E&S		4,474	1,410	3,260	2,752	7,422
300	Materials		12,646	3,986	9,215	7,780	20,980
301	Contractor		165	52	120	101	273
302	Non-Labor Overhead		43	14	31	26	71
303	Non-Labor Other		2,800	882	2,040	1,723	4,645
304	Contingency		-	-	-	-	-

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Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2025	(c) 4 Mos Ending 4/30/2026	(d) 12 Mos Ending 4/30/2027	(e) Projected 12 Mos Ending 4/30/2028	(f) 28 Mos Ending 4/30/2028
305	**Metro Failures**	**(53)**	**139**	**394**	**350**	**882**
306	Labor	(5)	14	39	34	87
307	Capitalized E&S	(8)	20	57	51	128
308	Materials	(1)	2	5	5	11
309	Contractor	-	-	-	-	-
310	Non-Labor Overhead	-	-	-	-	-
311	Non-Labor Other	(40)	103	293	260	656
312	Contingency	-	-	-	-	-
313	**Lines Relocations - LVD**	**88,913**	**30,492**	**137,618**	**131,401**	**299,511**
314	Labor	20,266	6,950	31,367	29,950	68,267
315	Capitalized E&S	17,782	6,098	27,522	26,279	59,899
316	Materials	14,550	4,990	22,521	21,503	49,014
317	Contractor	43,452	14,901	67,254	64,216	146,372
318	Non-Labor Overhead	5,100	1,749	7,893	7,536	17,178
319	Non-Labor Other	(12,236)	(4,196)	(18,939)	(18,084)	(41,220)
320	Contingency	-	-	-	-	-
321	**Lines Relocations - HVD**	**610**	**299**	**899**	**899**	**2,097**
322	Labor	44	22	65	65	152
323	Capitalized E&S	423	208	624	624	1,456
324	Materials	519	255	765	766	1,786
325	Contractor	1,239	608	1,825	1,827	4,261
326	Non-Labor Overhead	2	1	3	3	8
327	Non-Labor Other	(1,618)	(795)	(2,384)	(2,386)	(5,565)
328	Contingency	-	-	-	-	-
329	**Metro Relocations**	**14,353**	**8,676**	**17,526**	**18,270**	**44,471**
330	Labor	500	302	610	636	1,549
331	Capitalized E&S	3,100	1,874	3,785	3,946	9,604
332	Materials	2,385	1,442	2,913	3,036	7,391
333	Contractor	10,395	6,283	12,693	13,232	32,208
334	Non-Labor Overhead	68	41	83	86	210
335	Non-Labor Other	(2,095)	(1,266)	(2,558)	(2,666)	(6,490)
336	Contingency	-	-	-	-	-
337	**Lines Reliability - LVD**	**110,025**	**73,069**	**251,192**	**250,625**	**574,886**
338	Labor	20,942	13,908	47,812	47,704	109,424
339	Capitalized E&S	15,010	9,969	34,269	34,192	78,430
340	Materials	15,194	10,091	34,690	34,611	79,392
341	Contractor	33,901	22,514	77,398	77,223	177,135
342	Non-Labor Overhead	4,795	3,184	10,947	10,923	25,054
343	Non-Labor Other	20,182	13,403	46,076	45,972	105,451
344	Contingency	-	-	-	-	-
345	**Lines Reliability - HVD**	**101,058**	**40,801**	**94,884**	**108,778**	**244,463**
346	Labor	1,899	767	1,783	2,044	4,594
347	Capitalized E&S	16,219	6,548	15,228	17,458	39,235
348	Materials	22,941	9,262	21,540	24,694	55,496
349	Contractor	52,626	21,247	49,411	56,646	127,305
350	Non-Labor Overhead	209	84	196	225	505
351	Non-Labor Other	7,164	2,892	6,726	7,711	17,329
352	Contingency	-	-	-	-	-
353	**Substations Reliability - LVD**	**43,773**	**20,978**	**44,686**	**42,880**	**108,544**
354	Labor	1,200	575	1,225	1,175	2,975
355	Capitalized E&S	5,704	2,734	5,823	5,588	14,144
356	Materials	23,980	11,492	24,480	23,491	59,464
357	Contractor	10,380	4,975	10,597	10,169	25,740
358	Non-Labor Overhead	158	76	161	155	392
359	Non-Labor Other	2,351	1,127	2,400	2,303	5,829
360	Contingency	-	-	-	-	-

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($000)

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Date: June 2026

Line No	Description	(a)	(b) Historical Year 12 Mos Ended 12/31/2025	(c) 4 Mos Ending 4/30/2026	(d) 12 Mos Ending 4/30/2027	(e) Projected 12 Mos Ending 4/30/2028	(f) 28 Mos Ending 4/30/2028
361	**Substations Reliability - HVD**		**23,161**	**11,349**	**14,380**	**46,180**	**71,909**
362	Labor		2,328	1,141	1,446	4,643	7,229
363	Capitalized E&S		3,478	1,704	2,159	6,934	10,797
364	Materials		8,201	4,019	5,092	16,353	25,463
365	Contractor		7,341	3,597	4,558	14,638	22,794
366	Non-Labor Overhead		332	163	206	661	1,030
367	Non-Labor Other		1,480	725	919	2,951	4,596
368	Contingency		-	-	-	-	-
369	**Grid Capabilities - Automation**		**20,179**	**1,912**	**13,271**	**8,260**	**23,443**
370	Labor		611	58	402	250	710
371	Capitalized E&S		1,954	185	1,285	800	2,270
372	Materials		6,094	577	4,008	2,495	7,080
373	Contractor		5,443	516	3,580	2,228	6,324
374	Non-Labor Overhead		7	1	4	3	8
375	Non-Labor Other		6,070	575	3,992	2,484	7,051
376	Contingency		-	-	-	-	-
377	**System Protection**		**5,244**	**3,059**	**2,880**	**4,672**	**10,611**
378	Labor		710	414	390	633	1,438
379	Capitalized E&S		863	503	474	769	1,746
380	Materials		1,513	883	831	1,348	3,062
381	Contractor		1,683	982	924	1,500	3,406
382	Non-Labor Overhead		45	26	25	40	91
383	Non-Labor Other		429	250	236	382	869
384	Contingency		-	-	-	-	-
385	**Repetitive Outages - LVD**		**12,903**	**7,102**	**26,113**	**27,493**	**60,708**
386	Labor		2,148	1,182	4,348	4,578	10,108
387	Capitalized E&S		1,954	1,075	3,954	4,163	9,193
388	Materials		2,384	1,312	4,825	5,080	11,218
389	Contractor		4,173	2,297	8,445	8,891	19,633
390	Non-Labor Overhead		515	284	1,043	1,098	2,424
391	Non-Labor Other		1,729	951	3,498	3,683	8,133
392	Contingency		-	-	-	-	-
393	**Metro Reliability**		**4,629**	**1,333**	**3,998**	**4,131**	**9,462**
394	Labor		168	48	145	150	343
395	Capitalized E&S		858	247	741	766	1,754
396	Materials		953	274	823	851	1,948
397	Contractor		2,249	647	1,942	2,007	4,597
398	Non-Labor Overhead		27	8	24	24	56
399	Non-Labor Other		374	108	323	333	764
400	Contingency		-	-	-	-	-
401	**Transformer Bank Replacement and Substation Rebuild**		**22,285**	**5,837**	**20,768**	**37,155**	**63,760**
402	Labor		841	220	783	1,401	2,405
403	Capitalized E&S		2,888	756	2,691	4,814	8,262
404	Materials		12,121	3,175	11,295	20,208	34,679
405	Contractor		4,477	1,173	4,172	7,465	12,810
406	Non-Labor Overhead		80	21	74	133	227
407	Non-Labor Other		1,879	492	1,752	3,134	5,377
408	Contingency		-	-	-	-	-
409	**Substations Rehabilitation - LVD**		**22,174**	**9,003**	**21,997**	**31,328**	**62,328**
410	Labor		1,302	529	1,291	1,839	3,659
411	Capitalized E&S		3,687	1,497	3,658	5,210	10,365
412	Materials		11,556	4,692	11,463	16,326	32,482
413	Contractor		4,172	1,694	4,139	5,895	11,728
414	Non-Labor Overhead		202	82	200	285	567
415	Non-Labor Other		1,255	510	1,245	1,773	3,527
416	Contingency		-	-	-	-	-

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Line No	Description	(a)	(b) Historical Year 12 Mos Ended 12/31/2025	(c) 4 Mos Ending 4/30/2026	(d) 12 Mos Ending 4/30/2027	(e) Projected 12 Mos Ending 4/30/2028	(f) 28 Mos Ending 4/30/2028
417	**Lines Rehabilitation - LVD**		**16,847**	**6,826**	**26,980**	**22,977**	**56,782**
418	Labor		3,191	1,293	5,110	4,352	10,755
419	Capitalized E&S		2,811	1,139	4,502	3,834	9,476
420	Materials		4,760	1,928	7,623	6,492	16,043
421	Contractor		3,269	1,325	5,236	4,459	11,020
422	Non-Labor Overhead		793	321	1,270	1,082	2,674
423	Non-Labor Other		2,022	819	3,238	2,758	6,815
424	Contingency		-	-	-	-	-
417	**Metro Rehabilitation**		**4,512**	**984**	**1,968**	**5,495**	**8,448**
425	Labor		162	35	71	198	304
426	Capitalized E&S		768	168	335	936	1,439
427	Materials		971	212	424	1,183	1,819
428	Contractor		2,278	497	994	2,775	4,266
429	Non-Labor Overhead		23	5	10	28	44
430	Non-Labor Other		308	67	134	375	577
431	Contingency		-	-	-	-	-
432	**Grid Storage**		**(86)**	**-**	**-**	**-**	**-**
433	Labor		19	-	-	-	-
434	Capitalized E&S		-	-	-	-	-
435	Materials		0	-	-	-	-
436	Contractor		53	-	-	-	-
437	Non-Labor Overhead		0	-	-	-	-
438	Non-Labor Other		(159)	-	-	-	-
439	Contingency		-	-	-	-	-
440	**Resiliency**		**41,767**	**4,250**	**50,780**	**78,751**	**133,781**
441	Labor		7,845	798	9,538	14,792	25,128
442	Capitalized E&S		6,637	675	8,069	12,514	21,259
443	Materials		13,521	1,376	16,439	25,494	43,308
444	Contractor		6,947	707	8,447	13,099	22,253
445	Non-Labor Overhead		1,976	201	2,402	3,725	6,328
446	Non-Labor Other		4,841	493	5,885	9,127	15,505
447	Contingency		-	-	-	-	-
448	**Lines Capacity - LVD**		**17,876**	**8,834**	**31,027**	**53,485**	**93,346**
449	Labor		3,877	1,916	6,729	11,600	20,244
450	Capitalized E&S		2,696	1,332	4,679	8,067	14,078
451	Materials		3,621	1,789	6,285	10,834	18,908
452	Contractor		4,200	2,075	7,290	12,567	21,932
453	Non-Labor Overhead		979	484	1,700	2,931	5,115
454	Non-Labor Other		2,503	1,237	4,344	7,488	13,068
455	Contingency		-	-	-	-	-
456	**Lines & Subs Capacity - HVD**		**20,006**	**9,596**	**32,308**	**34,956**	**76,859**
457	Labor		658	315	1,062	1,149	2,527
458	Capitalized E&S		4,707	2,258	7,601	8,224	18,083
459	Materials		6,589	3,160	10,640	11,512	25,313
460	Contractor		14,813	7,105	23,922	25,883	56,910
461	Non-Labor Overhead		102	49	165	179	393
462	Non-Labor Other		(6,863)	(3,292)	(11,083)	(11,991)	(26,366)
463	Contingency		-	-	-	-	-
464	**Substations Capacity - LVD**		**33,612**	**9,433**	**9,451**	**22,399**	**41,284**
465	Labor		1,688	474	475	1,125	2,074
466	Capitalized E&S		5,885	1,652	1,655	3,922	7,229
467	Materials		15,110	4,241	4,249	10,070	18,559
468	Contractor		9,456	2,654	2,659	6,302	11,615
469	Non-Labor Overhead		188	53	53	126	231
470	Non-Labor Other		1,283	360	361	855	1,576
471	Contingency		-	-	-	-	-

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472	**Lines New Business Capacity - LVD**	**32,679**	**6,046**	**34,110**	**30,339**	**70,495**
473	Labor	6,977	1,291	7,282	6,477	15,051
474	Capitalized E&S	5,505	1,018	5,746	5,111	11,875
475	Materials	5,453	1,009	5,692	5,062	11,763
476	Contractor	8,620	1,595	8,998	8,003	18,595
477	Non-Labor Overhead	1,783	330	1,861	1,655	3,847
478	Non-Labor Other	4,341	803	4,531	4,030	9,365
479	Contingency	-	-	-	-	-
480	**Conservation Voltage Reduction**	**5,159**	**708**	**3,160**	**2,429**	**6,297**
481	Labor	772	106	473	364	943
482	Capitalized E&S	694	95	425	327	847
483	Materials	347	48	213	164	424
484	Contractor	2,386	327	1,462	1,124	2,913
485	Non-Labor Overhead	191	26	117	90	233
486	Non-Labor Other	768	105	470	362	937
487	Contingency	-	-	-	-	-
488	**Subs Solar Interconnections - HVD**	**0**	**-**	**-**	**-**	**-**
489	Labor	(0)	-	-	-	-
490	Capitalized E&S	0	-	-	-	-
491	Materials	(0)	-	-	-	-
492	Contractor	0	-	-	-	-
493	Non-Labor Overhead	-	-	-	-	-
494	Non-Labor Other	0	-	-	-	-
495	Contingency	-	-	-	-	-
496	**Computers & Equipment**	**(65)**	**25**	**75**	**75**	**175**
497	Labor	-	-	-	-	-
498	Capitalized E&S	-	-	-	-	-
499	Materials	-	-	-	-	-
500	Contractor	(64)	25	74	74	173
501	Non-Labor Overhead	-	-	-	-	-
502	Non-Labor Other	(1)	0	1	1	2
503	Contingency	-	-	-	-	-
504	**Tools**	**5,796**	**1,462**	**8,190**	**8,277**	**17,929**
505	Labor	0	0	0	0	0
506	Capitalized E&S	-	-	-	-	-
507	Materials	5,795	1,462	8,188	8,276	17,926
508	Contractor	1	0	1	1	3
509	Non-Labor Overhead	0	0	0	0	0
510	Non-Labor Other	0	0	0	0	0
511	Contingency	-	-	-	-	-
512	**System Control Projects**	**57**	**2**	**77**	**196**	**275**
513	Labor	5	0	6	16	23
514	Capitalized E&S	(2)	(0)	(3)	(8)	(11)
515	Materials	9	0	12	31	44
516	Contractor	17	1	23	60	84
517	Non-Labor Overhead	-	-	-	-	-
518	Non-Labor Other	28	1	38	97	136
519	Contingency	-	-	-	-	-
520	**Total Electric Distribution**	**$ 1,279,640**	**$ 393,232**	**$ 1,389,742**	**$ 1,460,571**	**$ 3,243,546**
521	Labor	193,111	58,709	217,191	220,198	496,097
522	Capitalized E&S	219,318	65,759	235,598	246,137	547,494
523	Materials	381,788	108,503	400,221	432,508	941,232
524	Contractor	336,807	118,763	383,740	410,566	913,069
525	Non-Labor Overhead	38,973	12,221	46,546	47,538	106,305
526	Non-Labor Other	109,644	29,279	106,446	103,624	239,349
527	Contingency	-	-	-	-	-

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Line No.	(a) Description	(b) Witness	(c) Historical Year 12 Mos Ended 12/31/2021	(d) Historical Year 12 Mos Ended 12/31/2022	(e) Historical Year 12 Mos Ended 12/31/2023	(f) Historical Year 12 Mos Ended 12/31/2024	(g) Historical Year 12 Mos Ended 12/31/2025	(h) 5yr Average	(i) Projected Bridge Year 12 Mos Ending 12/31/2026	(j) Projected Bridge Year 4 Mos Ending 4/30/2027	(k) Projected Bridge Year 16 Mos Ending 4/30/2027	(l) Projected Test Year 12 Mos Ending 4/30/2028	(m) Test Year vs 5yr Ave Variance (l - h)
1	Lines New Business - LVD	JMPartlan	$ 111,921	$ 128,886	$ 136,185	$ 116,118	$ 114,568	$ 121,535	$ 117,890	$ 37,626	$ 155,516	$ 121,618	$ 82
2	Lines Strategic Customers - HVD	KKLaFrance	20,268	4,280	11,071	57,836	40,821	26,855	39,549	3,456	43,005	48,064	21,209
3	Distribution Transformer Purchases	JMPartlan	37,927	49,209	64,137	122,886	152,452	85,322	144,655	43,063	187,718	138,661	53,338
4	Metro New Business	KKLaFrance	2,431	1,865	1,589	11,188	6,209	4,656	6,584	2,640	9,223	7,737	3,081
5	**New Business**		**172,546**	**184,240**	**212,982**	**308,029**	**314,050**	**238,369**	**308,677**	**86,785**	**395,462**	**316,079**	**77,710**
6	Lines Failures - LVD	JMPartlan	123,576	142,777	159,371	164,353	266,151	171,245	179,495	43,635	223,131	134,513	(36,733)
7	Lines & Subs Failures - HVD	KKLaFrance	6,050	10,015	13,524	11,692	13,380	10,932	8,324	3,333	11,657	10,333	(599)
8	Substations Failures - LVD	KKLaFrance	12,782	8,056	14,869	11,478	11,268	11,691	11,050	2,150	13,200	11,000	(691)
9	Distribution Meter Purchases	JMPartlan	22,368	30,975	58,653	35,077	27,380	34,890	22,525	6,054	28,580	16,843	(18,047)
10	Metro Failures	KKLaFrance	50	122	464	18	(53)	120	416	117	532	350	230
11	**Demand Failures**		**164,825**	**191,943**	**246,880**	**222,618**	**318,126**	**228,879**	**221,811**	**55,290**	**277,100**	**173,040**	**(55,839)**
12	Lines Relocations - LVD	JMPartlan	38,895	52,814	46,848	51,502	88,913	55,794	128,106	40,003	168,109	131,401	75,607
13	Lines Relocations - HVD	KKLaFrance	1,709	2,565	5,319	845	610	2,210	898	300	1,198	899	(1,310)
14	Metro Relocations	KKLaFrance	6,550	6,888	5,161	11,420	14,353	8,874	19,400	6,802	26,201	18,270	9,396
15	**Asset Relocations**		**47,154**	**62,267**	**57,328**	**63,767**	**103,876**	**66,878**	**148,405**	**47,104**	**195,509**	**150,570**	**83,692**
16	Lines Reliability - LVD	JMPartlan	39,451	50,631	34,935	31,432	110,025	53,295	193,837	130,424	324,261	250,625	197,330
17	Lines Reliability - HVD	KKLaFrance	58,092	42,565	21,703	32,264	99,314	50,788	92,967	42,718	135,685	108,778	57,990
18	Substations Reliability - LVD	KKLaFrance	19,017	16,884	14,709	17,574	43,773	22,391	41,653	24,011	65,664	42,880	20,488
19	Substations Reliability - HVD	KKLaFrance	3,456	3,993	3,262	5,715	23,161	7,917	15,080	10,649	25,729	46,180	38,263
20	Grid Capabilities - Automation	SAMcPhail	74,154	52,816	29,038	20,162	20,179	39,270	11,510	3,673	15,183	8,260	(31,010)
21	System Protection	KKLaFrance	2,620	4,504	4,387	4,848	5,244	4,320	4,462	1,478	5,939	4,672	352
22	Repetitive Outages - LVD	JMPartlan	10,714	9,254	4,082	4,491	12,903	8,289	23,080	10,135	33,215	27,493	19,204
23	Metro Reliability	KKLaFrance	5,737	4,125	3,985	6,690	4,629	5,033	3,998	1,333	5,330	4,131	(902)
24	Transformer Bank Replacement and Substation Rebuild	KKLaFrance	29,857	39,184	28,395	26,676	22,285	29,279	15,371	11,234	26,605	37,155	7,876
25	Substations Rehabilitation - LVD	KKLaFrance	18,379	10,941	8,482	13,860	22,174	14,767	25,701	5,299	31,000	31,328	16,560
26	Lines Rehabilitation - LVD	JMPartlan	33,548	29,068	12,530	12,807	16,847	20,960	20,031	13,774	33,805	22,977	2,017
27	Metro Rehabilitation	KKLaFrance	3,163	4,678	7,034	2,688	4,512	4,415	2,953	(0)	2,953	5,495	1,080
28	Grid Storage	N/A	4,606	(6,018)	245	(756)	(86)	(402)	-	-	-	-	402
29	Resiliency	JMPartlan	-	-	1,438	40,654	43,511	17,121	20,143	34,887	55,030	78,751	61,630
30	**Reliability**		**302,794**	**262,625**	**174,225**	**219,105**	**428,469**	**277,443**	**470,784**	**289,616**	**760,400**	**668,725**	**391,282**
31	Lines Capacity - LVD	JMPartlan	8,217	7,706	2,927	9,424	17,876	9,230	15,134	24,726	39,861	53,485	44,255
32	Lines & Subs Capacity - HVD	KKLaFrance	17,365	29,292	25,805	27,163	20,006	23,926	20,286	21,618	41,904	34,956	11,029
33	Substations Capacity - LVD	KKLaFrance	15,068	12,767	14,530	25,887	33,612	20,373	10,761	8,124	18,885	22,399	2,027
34	Lines New Business Capacity - LVD	JMPartlan	23,672	27,188	29,054	33,430	32,679	29,205	26,785	13,371	40,156	30,339	1,134
35	Conservation Voltage Reduction	JMPartlan	7,191	3,145	1,311	2,246	5,159	3,810	2,459	1,409	3,868	2,429	(1,381)
36	Lines Solar Interconnections - LVD	N/A	-	-	2	-	-	0	-	-	-	-	(0)
37	Subs Solar Interconnections - HVD	N/A	-	-	-	85	0	17	-	-	-	-	(17)
38	**Capacity**		**71,514**	**80,098**	**73,629**	**98,235**	**109,331**	**86,561**	**75,426**	**69,247**	**144,673**	**143,608**	**57,047**
39	Computers & Equipment	KKLaFrance	378	6,273	412	-	(65)	1,400	75	25	100	75	(1,325)
40	Tools	JMPartlan	5,214	5,257	4,560	7,773	5,796	5,720	8,177	1,475	9,652	8,277	2,557
41	System Control Projects	KKLaFrance	1,193	2,179	41	896	57	873	6	73	79	196	(677)
42	**Electric Other**		**6,786**	**13,709**	**5,014**	**8,669**	**5,788**	**7,993**	**8,258**	**1,573**	**9,831**	**8,548**	**555**
43	**Total Electric Distribution**		**$ 765,619**	**$ 794,882**	**$ 770,057**	**$ 920,423**	**$ 1,279,640**	**$ 906,124**	**$ 1,233,360**	**$ 549,615**	**$ 1,782,975**	**$ 1,460,571**	**$ 554,447**

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Date: June 2026

Line No.	(a) Description	(b) Witness	(c) Historical Year 12 Mos Ended 12/31/2021	(d) Historical Year 12 Mos Ended 12/31/2022	(e) Historical Year 12 Mos Ended 12/31/2023	(f) Historical Year 12 Mos Ended 12/31/2024	(g) Historical Year 12 Mos Ended 12/31/2025	(h) 5yr Average	(i) Projected 4 Mos Ending 4/30/2026	(j) Projected 12 Mos Ending 4/30/2027	(k) Projected 12 Mos Ending 4/30/2028	(l) Projected 28 Mos Ending 4/30/2028
44	Lines New Business - LVD	JMPartlan	$ 111,921	$ 128,886	$ 136,185	$ 116,118	$ 114,568	$ 121,535	$ 34,600	$ 120,916	$ 121,618	$ 277,133
45	Lines Strategic Customers - HVD	KKLaFrance	20,268	4,280	11,071	57,836	40,821	26,855	9,183	33,822	48,064	91,069
46	Distribution Transformer Purchases	JMPartlan	37,927	49,209	64,137	122,886	152,452	85,322	24,141	163,577	138,661	326,379
47	Metro New Business	KKLaFrance	2,431	1,865	1,589	11,188	6,209	4,656	2,098	7,125	7,737	16,960
48	**New Business**		**172,546**	**184,240**	**212,982**	**308,029**	**314,050**	**238,369**	**70,021**	**325,441**	**316,079**	**711,541**
49	Lines Failures - LVD	JMPartlan	123,576	142,777	159,371	164,353	266,151	171,245	46,434	176,697	134,513	357,644
50	Lines & Subs Failures - HVD	KKLaFrance	6,050	10,015	13,524	11,692	13,380	10,932	2,217	9,441	10,333	21,991
51	Substations Failures - LVD	KKLaFrance	12,782	8,056	14,869	11,478	11,268	11,691	3,717	9,483	11,000	24,200
52	Distribution Meter Purchases	JMPartlan	22,368	30,975	58,653	35,077	27,380	34,890	8,629	19,950	16,843	45,423
53	Metro Failures	KKLaFrance	50	122	464	18	(53)	120	139	394	350	882
54	**Demand Failures**		**164,825**	**191,943**	**246,880**	**222,618**	**318,126**	**228,879**	**61,135**	**215,965**	**173,040**	**450,140**
55	Lines Relocations - LVD	JMPartlan	38,895	52,814	46,848	51,502	88,913	55,794	30,492	137,618	131,401	299,511
56	Lines Relocations - HVD	KKLaFrance	1,709	2,565	5,319	845	610	2,210	299	899	899	2,097
57	Metro Relocations	KKLaFrance	6,550	6,888	5,161	11,420	14,353	8,874	8,676	17,526	18,270	44,471
58	**Asset Relocations**		**47,154**	**62,267**	**57,328**	**63,767**	**103,876**	**66,878**	**39,467**	**156,042**	**150,570**	**346,079**
59	Lines Reliability - LVD	JMPartlan	39,451	50,631	34,935	31,432	110,025	53,295	73,069	251,192	250,625	574,886
60	Lines Reliability - HVD	KKLaFrance	58,092	42,565	21,703	32,264	99,314	50,788	40,801	94,884	108,778	244,463
61	Substations Reliability - LVD	KKLaFrance	19,017	16,884	14,709	17,574	43,773	22,391	20,978	44,686	42,880	108,544
62	Substations Reliability - HVD	KKLaFrance	3,456	3,993	3,262	5,715	23,161	7,917	11,349	14,380	46,180	71,909
63	Grid Capabilities - Automation	SAMcPhail	74,154	52,816	29,038	20,162	20,179	39,270	1,912	13,271	8,260	23,443
64	System Protection	KKLaFrance	2,620	4,504	4,387	4,848	5,244	4,320	3,059	2,880	4,672	10,611
65	Repetitive Outages - LVD	JMPartlan	10,714	9,254	4,082	4,491	12,903	8,289	7,102	26,113	27,493	60,708
66	Metro Reliability	KKLaFrance	5,737	4,125	3,985	6,690	4,629	5,033	1,333	3,998	4,131	9,462
67	Transformer Bank Replacement and Substation Rebuild	KKLaFrance	29,857	39,184	28,395	26,676	22,285	29,279	5,837	20,768	37,155	63,760
68	Substations Rehabilitation - LVD	KKLaFrance	18,379	10,941	8,482	13,860	22,174	14,767	9,003	21,997	31,328	62,328
69	Lines Rehabilitation - LVD	JMPartlan	33,548	29,068	12,530	12,807	16,847	20,960	6,826	26,980	22,977	56,782
70	Metro Rehabilitation	KKLaFrance	3,163	4,678	7,034	2,688	4,512	4,415	984	1,968	5,495	8,448
71	Grid Storage	N/A	4,606	(6,018)	245	(756)	(86)	(402)	-	-	-	-
72	Resiliency	JMPartlan	-	-	1,438	40,654	43,511	17,121	4,250	50,780	78,751	133,781
73	**Reliability**		**302,794**	**262,625**	**174,225**	**219,105**	**428,469**	**277,443**	**186,503**	**573,897**	**668,725**	**1,429,125**
74	Lines Capacity - LVD	JMPartlan	8,217	7,706	2,927	9,424	17,876	9,230	8,834	31,027	53,485	93,346
75	Lines & Subs Capacity - HVD	KKLaFrance	17,365	29,292	25,805	27,163	20,006	23,926	9,596	32,308	34,956	76,859
76	Substations Capacity - LVD	KKLaFrance	15,068	12,767	14,530	25,887	33,612	20,373	9,433	9,451	22,399	41,284
77	Lines New Business Capacity - LVD	JMPartlan	23,672	27,188	29,054	33,430	32,679	29,205	6,046	34,110	30,339	70,495
78	Conservation Voltage Reduction	JMPartlan	7,191	3,145	1,311	2,246	5,159	3,810	708	3,160	2,429	6,297
79	Lines Solar Interconnections - LVD	N/A	-	-	2	-	-	0	-	-	-	-
80	Subs Solar Interconnections - HVD	N/A	-	-	-	85	0	17	-	-	-	-
81	**Capacity**		**71,514**	**80,098**	**73,629**	**98,235**	**109,331**	**86,561**	**34,617**	**110,056**	**143,608**	**288,281**
82	Computers & Equipment	KKLaFrance	378	6,273	412	-	(65)	1,400	25	75	75	175
83	Tools	JMPartlan	5,214	5,257	4,560	7,773	5,796	5,720	1,462	8,190	8,277	17,929
84	System Control Projects	KKLaFrance	1,193	2,179	41	896	57	873	2	77	196	275
85	**Electric Other**		**6,786**	**13,709**	**5,014**	**8,669**	**5,788**	**7,993**	**1,489**	**8,342**	**8,548**	**18,380**
86	**Total Electric Distribution**		**$ 765,619**	**$ 794,882**	**$ 770,057**	**$ 920,423**	**$ 1,279,640**	**$ 906,124**	**$ 393,232**	**$ 1,389,742**	**$ 1,460,571**	**$ 3,243,546**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Consumers Energy Company
Actual and Projected Capital Expenditures - Over/Under $5 Million
Electric Distribution

Case No.: U-22070
Exhibit No.: A-88 (EMD-4)
Page: 1 of 1
Witness: EMDuke
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2025	12 Mos Ending 12/31/2026	4 Mos Ending 4/30/2027	16 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028
	Projects Over $5 Million (with spend in test year)					
1	Lines New Business - LVD	$ 114,568	$ 117,890	$ 37,626	$ 155,516	$ 121,618
2	Lines Strategic Customers - HVD	40,821	39,549	3,456	43,005	48,064
3	Distribution Transformer Purchases	152,452	144,655	43,063	187,718	138,661
4	Metro New Business	6,209	6,584	2,640	9,223	7,737
5	Lines Failures - LVD	266,151	179,495	43,635	223,131	134,513
6	Lines & Subs Failures - HVD	13,380	8,324	3,333	11,657	10,333
7	Substations Failures - LVD	11,268	11,050	2,150	13,200	11,000
8	Distribution Meter Purchases	27,380	22,525	6,054	28,580	16,843
9	Lines Relocations - LVD	88,913	128,106	40,003	168,109	131,401
10	Metro Relocations	14,353	19,400	6,802	26,201	18,270
11	Lines Reliability - LVD	110,025	193,837	130,424	324,261	250,625
12	Lines Reliability - HVD	101,058	92,967	42,718	135,685	108,778
13	Substations Reliability - LVD	43,773	41,653	24,011	65,664	42,880
14	Substations Reliability - HVD	23,161	15,080	10,649	25,729	46,180
15	Grid Capabilities - Automation	20,179	11,510	3,673	15,183	8,260
16	Repetitive Outages - LVD	12,903	23,080	10,135	33,215	27,493
17	Transformer Bank Replacement and Substation Rebuild	22,285	15,371	11,234	26,605	37,155
18	Substations Rehabilitation - LVD	22,174	25,701	5,299	31,000	31,328
19	Lines Rehabilitation - LVD	16,847	20,031	13,774	33,805	22,977
20	Metro Rehabilitation	4,512	2,953	(0)	2,953	5,495
21	Resiliency	41,767	20,143	34,887	55,030	78,751
22	Lines Capacity - LVD	17,876	15,134	24,726	39,861	53,485
23	Lines & Subs Capacity - HVD	20,006	20,286	21,618	41,904	34,956
24	Substations Capacity - LVD	33,612	10,761	8,124	18,885	22,399
25	Lines New Business Capacity - LVD	32,679	26,785	13,371	40,156	30,339
26	Tools	5,796	8,177	1,475	9,652	8,277
	Projects Under $5 Million					
27	Metro Failures	(53)	416	117	532	350
28	Lines Relocations - HVD	610	898	300	1,198	899
29	System Protection	5,244	4,462	1,478	5,939	4,672
30	Metro Reliability	4,629	3,998	1,333	5,330	4,131
31	Grid Storage	(86)	-	-	-	-
32	Conservation Voltage Reduction	5,159	2,459	1,409	3,868	2,429
33	Subs Solar Interconnections - HVD	0	-	-	-	-
34	Computers & Equipment	(65)	75	25	100	75
35	System Control Projects	57	6	73	79	196
36	**Electric Distribution**	**$ 1,279,640**	**$ 1,233,360**	**$ 549,615**	**$ 1,782,975**	**$ 1,460,571**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M
Electric Distribution
($000)

Case No.: U-22070
Exhibit No.: A-89 (EMD-5)
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Witness: EMDuke
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) 12 Mos Ended 12/31/2026	(d) Bridge Period 4 Mos Ending 4/30/2027	(e) 16 Mos Ending 4/30/2027	(f) Projected 12 Months Ending 4/30/2028
1	**Electric Distribution**	**$ 283,019**	**$ 291,758**	**$ 102,440**	**$ 394,198**	**$ 321,655**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected O&M
Electric Distribution
($000)

Case No.: U-22070
Exhibit No.: A-90 (EMD-6)
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Witness: EMDuke
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) 12 Mos 12/31/2026	(d) Bridge Period 4 Mos 4/30/2027	(e) 16 Mos 4/30/2027	(f) Projected 12 Months Ending 4/30/2028
1	Service Restoration - LVD	$ 181,250	$ 181,250	$ 60,416	$ 241,667	$ 192,571
2	Low Voltage Distribution	46,703	51,160	18,771	69,931	61,792
3	High Voltage Distribution	25,832	27,204	9,608	36,812	30,075
4	Grid Ops & Restoration	7,782	10,886	4,613	15,499	12,441
5	Performance Innovation & Strategy	14,489	14,902	6,694	21,596	17,437
6	Management & Chargebacks	5,271	4,760	1,747	6,507	5,564
7	Work Management & Customer Delivery	1,691	1,596	591	2,187	1,775
8	**Total Electric Distribution**	**$ 283,019**	**$ 291,758**	**$ 102,440**	**$ 394,198**	**$ 321,655**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected O&M Cost Splits
Electric Distribution
($000)

Case No.: U-22070
Exhibit No.: A-91 (EMD-7)
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Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
1	**Service Restoration - LVD**	**$ 181,250**	**$ 192,571**
2	Labor	73,106	77,672
3	Material	6,775	7,198
4	Contractor	62,543	66,449
5	Non-Labor Overheads	6,145	6,528
6	Non-Labor Other	32,682	34,723
7	**LVD Engineering**	**3,501**	**5,486**
8	Labor	950	1,488
9	Material	0	0
10	Contractor	0	0
11	Non-Labor Overheads	0	0
12	Non-Labor Other	2,551	3,998
13	**Lines Reliability - LVD**	**1,940**	**7,066**
14	Labor	851	3,098
15	Material	314	1,142
16	Contractor	12	42
17	Non-Labor Overheads	34	126
18	Non-Labor Other	730	2,657
19	**Corrective Maintenance**	**6,030**	**5,163**
20	Labor	5,288	4,528
21	Material	287	246
22	Contractor	392	336
23	Non-Labor Overheads	470	402
24	Non-Labor Other	-406	-348
25	**Staking**	**12,022**	**15,388**
26	Labor	0	0
27	Material	0	0
28	Contractor	0	0
29	Non-Labor Overheads	0	0
30	Non-Labor Other	12,022	15,388
31	**Meter Services**	**11,712**	**13,527**
32	Labor	10,041	11,597
33	Material	28	32
34	Contractor	78	90
35	Non-Labor Overheads	1,383	1,598
36	Non-Labor Other	183	211
37	**Streetlighting**	**2,214**	**2,107**
38	Labor	1,084	1,032
39	Material	-49	-47
40	Contractor	1,086	1,033
41	Non-Labor Overheads	94	90
42	Non-Labor Other	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected O&M Cost Splits
Electric Distribution
($000)

Case No.: U-22070
Exhibit No.: A-91 (EMD-7)
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Witness: EMDuke
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
43	**Service Calls**	**4,620**	**4,906**
43	Labor	4,233	4,494
43	Material	114	121
43	Contractor	667	708
43	Non-Labor Overheads	455	483
43	Non-Labor Other	-848	-901
44	**LVD Field Operations Expenses**	**1,905**	**3,096**
45	Labor	8	13
46	Material	0	0
47	Contractor	0	0
48	Non-Labor Overheads	0	0
49	Non-Labor Other	1,897	3,082
50	**LVD Operations**	**2,279**	**2,452**
50	Labor	1,868	2,010
51	Material	0	0
51	Contractor	136	146
52	Non-Labor Overheads	0	0
52	Non-Labor Other	275	296
53	**Underground Workforce**	**479**	**2,601**
54	Labor	373	2,029
55	Material	0	0
56	Contractor	0	0
57	Non-Labor Overheads	0	0
58	Non-Labor Other	105	572
59	**Lines Reliability - HVD**	**99**	**344**
60	Labor	4	12
61	Material	8	28
62	Contractor	64	223
63	Non-Labor Overheads	0	2
64	Non-Labor Other	23	79
65	**Substations Reliability - LVD**	**4,669**	**5,136**
66	Labor	3,247	3,572
67	Material	215	236
68	Contractor	832	915
69	Non-Labor Overheads	506	557
70	Non-Labor Other	-131	-144
71	**Substations Reliability - HVD**	**2,981**	**3,120**
72	Labor	2,370	2,480
73	Material	40	42
74	Contractor	273	286
75	Non-Labor Overheads	273	285
76	Non-Labor Other	26	27

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected O&M Cost Splits
Electric Distribution
($000)

Case No.: U-22070
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Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
77	**HVD Engineering**	**5,265**	**7,031**
78	Labor	2,921	3,901
79	Material	0	0
80	Contractor	0	0
81	Non-Labor Overheads	1	1
82	Non-Labor Other	2,343	3,128
83	**Lines Demand - HVD**	**1,034**	**1,500**
84	Labor	755	1,096
85	Material	14	20
86	Contractor	952	1,382
87	Non-Labor Overheads	9	12
88	Non-Labor Other	-696	-1,010
89	**Substations Demand - LVD**	**5,458**	**5,800**
90	Labor	4,469	4,750
91	Material	315	334
92	Contractor	102	109
93	Non-Labor Overheads	486	517
94	Non-Labor Other	85	91
95	**Substations Demand - HVD**	**4,602**	**5,000**
96	Labor	3,172	3,447
97	Material	844	918
98	Contractor	182	197
99	Non-Labor Overheads	347	377
100	Non-Labor Other	56	61
101	**Alma Equipment Repair**	**381**	**475**
102	Labor	337	421
103	Material	64	80
104	Contractor	74	93
105	Non-Labor Overheads	31	39
106	Non-Labor Other	-126	-157
107	**HVD Field Operations Expenses**	**230**	**363**
107	Labor	0	0
108	Material	0	0
108	Contractor	0	0
109	Non-Labor Overheads	0	0
109	Non-Labor Other	230	363
110	**HVD Operations**	**1,115**	**1,307**
111	Labor	1,012	1,187
112	Material	0	0
113	Contractor	0	0
114	Non-Labor Overheads	0	0
115	Non-Labor Other	103	120

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected O&M Cost Splits
Electric Distribution
($000)

Case No.: U-22070
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Witness: EMDuke
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
116	**Meter Credits**	**-9,038**	**-5,016**
117	Labor	0	0
118	Material	0	0
119	Contractor	0	0
120	Non-Labor Overheads	0	0
121	Non-Labor Other	-9,038	-5,016
122	**Meter Tech & Mgmt Sys Support**	**1,182**	**1,290**
123	Labor	1,050	1,145
124	Material	0	0
125	Contractor	0	0
126	Non-Labor Overheads	0	0
127	Non-Labor Other	132	144
128	**Smart Energy MTC - Elec**	**9,488**	**9,690**
129	Labor	0	0
130	Material	0	0
131	Contractor	127	130
132	Non-Labor Overheads	0	0
133	Non-Labor Other	9,361	9,560
134	**Grid Management - Distr**	**4,137**	**4,164**
135	Labor	3,532	3,555
136	Material	0	0
137	Contractor	12	12
138	Non-Labor Overheads	6	6
139	Non-Labor Other	587	591
140	**Grid Automation**	**2,012**	**2,313**
141	Labor	260	298
142	Material	0	0
143	Contractor	0	0
144	Non-Labor Overheads	0	0
145	Non-Labor Other	1,753	2,015
146	**Electric Distribution Strategy**	**1,463**	**702**
147	Labor	126	61
148	Material	0	0
149	Contractor	0	0
150	Non-Labor Overheads	0	0
151	Non-Labor Other	1,337	641
152	**Training**	**9,798**	**13,200**
153	Labor	9,181	12,369
154	Material	39	53
155	Contractor	0	0
156	Non-Labor Overheads	36	49
157	Non-Labor Other	541	729

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected O&M Cost Splits
Electric Distribution
($000)

Case No.: U-22070
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Witness: EMDuke
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
158	**Tools**	**1,223**	**1,751**
158	Labor	109	157
158	Material	0	0
158	Contractor	0	0
158	Non-Labor Overheads	0	0
158	Non-Labor Other	1,114	1,594
159	**Performance and Innovation**	**2,005**	**1,784**
160	Labor	1,172	1,043
161	Material	0	0
162	Contractor	0	0
163	Non-Labor Overheads	0	0
164	Non-Labor Other	833	741
165	**Management & Chargebacks**	**5,271**	**5,564**
166	Labor	4,225	4,459
167	Material	783	826
168	Contractor	0	0
169	Non-Labor Overheads	0	0
170	Non-Labor Other	264	278
171	**Work Management & Customer Delivery**	**1,691**	**1,775**
172	Labor	1,269	1,332
173	Material	0	0
174	Contractor	51	54
175	Non-Labor Overheads	0	0
176	Non-Labor Other	371	389
177	**Total Electric Distribution O&M Expenses**	**$ 283,019**	**$ 321,655**
178	Labor	137,012	153,246
179	Material	9,789	11,229
180	Contractor	67,585	72,207
181	Non-Labor Overheads	10,276	11,071
182	Non-Labor Other	58,356	73,903

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected O&M Using Inflation
Electric Distribution
($000)

Case No.: U-22070
Exhibit No.: A-92 (EMD-8)
Page: 1 of 1
Witness: EMDuke
Date: June 2026

Line No.	(a) Description	(b) Actual 12 Mos Ending 12/31/2025	(c) Inflation Applied to Projected Test Year (b) * Compounded Inflation Rate	(d) Scope/ Cost Increases Net of Productivity Gains	(e) Projected O&M 12 Mos Ending 4/30/2028 (b) + (c) + (d)
1	Service Restoration - LVD	$ 181,250	$ 11,321	-	$ 192,571
2	LVD Engineering	3,501	219	1,766	5,486
3	Lines Reliability - LVD	1,940	121	5,004	7,066
4	Corrective Maintenance	6,030	377	(1,244)	5,163
5	Staking	12,022	751	2,615	15,388
6	Meter Services	11,712	732	1,084	13,527
7	Streetlighting	2,214	138	(245)	2,107
8	Service Calls	4,620	289	(3)	4,906
9	LVD Field Operations Expenses	1,905	119	1,072	3,096
10	LVD Operations	2,279	142	30	2,452
11	Underground Workforce	479	30	2,092	2,601
12	Lines Reliability - HVD	99	6	238	344
13	Substations Reliability - LVD	4,669	292	176	5,136
14	Substations Reliability - HVD	2,981	186	(47)	3,120
15	HVD Engineering	5,265	329	1,436	7,031
16	Lines Demand - HVD	1,034	65	402	1,500
17	Substations Demand - LVD	5,458	341	1	5,800
18	Substations Demand - HVD	4,602	287	111	5,000
19	Alma Equipment Repair	381	24	70	475
20	HVD Field Operations Expenses	230	14	119	363
21	HVD Operations	1,115	70	123	1,307
22	Meter Credits	(9,038)	(564)	4,586	(5,016)
23	Meter Tech & Mgmt Sys Support	1,182	74	34	1,290
24	Smart Energy MTC - Elec	9,488	593	(391)	9,690
25	Grid Management - Distr	4,137	258	(231)	4,164
26	Grid Automation	2,012	126	176	2,313
27	Electric Distribution Strategy	1,463	91	(853)	702
28	Training	9,798	612	2,791	13,200
29	Tools	1,223	76	451	1,751
30	Performance and Innovation	2,005	125	(346)	1,784
31	Management & Chargebacks	5,271	329	(37)	5,564
32	Work Management & Customer Delivery	1,691	106	(22)	1,775
33	**Total Electric Distribution O&M Expenses**	$ 283,019	$ 17,677	$ 20,960	$ 321,655

Notes

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected O&M
Electric Distribution
($000)

Case No.: U-22070
Exhibit No.: A-93 (EMD-9)
Page: 1 of 1
Witness: EMDuke
Date: June 2026

Line No.	(a) Description	(b) Actual 12 Mos Ending 12/31/2025	(c) 12 Mos Ended 12/31/2026	(d) Bridge Period 4 Mos Ending 4/30/2027	(e) 16 Mos Ending 4/30/2027	(f) Projected 12 Months Ending 4/30/2028
1	**Service Restoration - LVD**	**$ 181,250**	**$ 181,250**	**$ 60,416**	**$ 241,667**	**$ 192,571**
2	LVD Engineering	3,501	4,014	1,446	5,460	5,486
3	Lines Reliability - LVD	1,940	3,975	1,358	5,333	7,066
4	Corrective Maintenance	6,030	4,728	1,676	6,404	5,163
5	Staking	12,022	13,627	4,029	17,656	15,388
6	Meter Services	11,712	12,885	5,156	18,041	13,527
7	Streetlighting	2,214	1,695	861	2,556	2,107
8	Service Calls	4,620	4,237	1,602	5,839	4,906
9	LVD Field Operations Expenses	1,905	2,671	1,019	3,691	3,096
10	LVD Operations	2,279	2,087	796	2,882	2,452
11	Underground Workforce	479	1,241	828	2,069	2,601
12	**Low Voltage Distribution**	**46,703**	**51,160**	**18,771**	**69,931**	**61,792**
13	Lines Reliability - HVD	99	175	111	286	344
14	Substations Reliability - LVD	4,669	5,061	1,519	6,580	5,136
15	Substations Reliability - HVD	2,981	2,613	751	3,364	3,120
16	HVD Engineering	5,265	5,895	2,031	7,925	7,031
17	Lines Demand - HVD	1,034	1,200	854	2,054	1,500
18	Substations Demand - LVD	5,458	5,528	2,043	7,571	5,800
19	Substations Demand - HVD	4,602	4,716	1,570	6,286	5,000
20	Alma Equipment Repair	381	468	183	652	475
21	HVD Field Operations Expenses	230	349	120	468	363
22	HVD Operations	1,115	1,198	426	1,625	1,307
23	**High Voltage Distribution**	**25,832**	**27,204**	**9,608**	**36,812**	**30,075**
24	Meter Credits	(9,038)	(6,760)	(1,481)	(8,241)	(5,016)
25	Meter Tech & Mgmt Sys Support	1,182	1,080	401	1,481	1,290
26	Smart Energy MTC - Elec	9,488	9,462	3,230	12,691	9,690
27	Grid Management - Distr	4,137	4,705	1,378	6,083	4,164
28	Grid Automation	2,012	2,400	1,086	3,485	2,313
29	**Grid Ops & Restoration**	**7,782**	**10,886**	**4,613**	**15,499**	**12,441**
30	Electric Distribution Strategy	1,463	787	235	1,022	702
31	Training	9,798	11,211	5,263	16,474	13,200
32	Tools	1,223	1,223	615	1,838	1,751
33	Performance and Innovation	2,005	1,681	581	2,262	1,784
34	**Performance Innovation & Strategy**	**14,489**	**14,902**	**6,694**	**21,596**	**17,437**
35	**Management & Chargebacks**	**5,271**	**4,760**	**1,747**	**6,507**	**5,564**
36	**Work Management & Customer Delivery**	**1,691**	**1,596**	**591**	**2,187**	**1,775**
37	**Total Electric Operations**	**$ 283,019**	**$ 291,758**	**$ 102,440**	**$ 394,198**	**$ 321,655**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of 5yr Historical and Projected O&M Expenses
Electric Distribution
($000)

Case No.: U-22070
Exhibit No.: A-94 (EMD-10)
Page: 1 of 1
Witness: EMDuke
Date: June 2026

Line No.	(a) Description	(b) Actual 12 Mos Ending 12/31/2021	(c) Actual 12 Mos Ending 12/31/2022	(d) Actual 12 Mos Ending 12/31/2023	(e) Actual 12 Mos Ending 12/31/2024	(f) Actual 12 Mos Ending 12/31/2025	(g) 5-Year Average	(i) 12 Mos Ended 12/31/2026	(j) Bridge Period 4 Mos Ending 4/30/2027	(k) 16 Mos Ending 4/30/2027	(l) Projected 12 Months Ending 4/30/2028	(m) Test Year vs. 5-Year Average
1	**Service Restoration - LVD**	**$ 159,659**	**$ 113,271**	**$ 188,041**	**$ 156,098**	**$ 181,250**	**$ 159,664**	**$ 181,250**	**$ 60,416**	**$ 241,667**	**$ 192,571**	**$ 32,907**
2	LVD Engineering	6,359	6,596	6,148	5,979	3,501	5,716	4,014	1,446	5,460	5,486	(231)
3	Lines Reliability - LVD	527	1,097	651	580	1,940	959	3,975	1,358	5,333	7,066	6,106
4	Corrective Maintenance	4,535	4,131	4,130	4,615	6,030	4,688	4,728	1,676	6,404	5,163	475
5	Staking	3,251	3,587	3,975	6,148	12,022	5,797	13,627	4,029	17,656	15,388	9,591
6	Meter Services	8,635	9,635	11,559	11,165	11,712	10,541	12,885	5,156	18,041	13,527	2,986
7	Streetlighting	2,109	1,801	1,571	1,612	2,214	1,861	1,695	861	2,556	2,107	246
8	Service Calls	4,518	4,110	4,434	4,194	4,620	4,375	4,237	1,602	5,839	4,906	531
9	LVD Field Operations Expenses	2,136	1,955	2,121	1,915	1,905	2,007	2,671	1,019	3,691	3,096	1,089
10	LVD Operations	3,308	4,304	1,969	2,031	2,279	2,778	2,087	796	2,882	2,452	(326)
11	Underground Workforce	128	172	327	713	479	364	1,241	828	2,069	2,601	2,237
12	**Low Voltage Distribution**	**35,505**	**37,390**	**36,884**	**38,951**	**46,703**	**39,087**	**51,160**	**18,771**	**69,931**	**61,792**	**22,705**
13	Lines Reliability - HVD	188	287	261	109	99	189	175	111	286	344	155
14	Substations Reliability - LVD	2,771	2,992	3,100	3,565	4,669	3,419	5,061	1,519	6,580	5,136	1,717
15	Substations Reliability - HVD	1,925	2,017	2,181	2,350	2,981	2,291	2,613	751	3,364	3,120	829
16	HVD Engineering	5,552	5,631	5,082	5,475	5,265	5,401	5,895	2,031	7,925	7,031	1,630
17	Lines Demand - HVD	784	1,086	654	898	1,034	891	1,200	854	2,054	1,500	609
18	Substations Demand - LVD	2,995	4,707	4,092	4,302	5,458	4,311	5,528	2,043	7,571	5,800	1,489
19	Substations Demand - HVD	2,986	3,159	3,383	4,050	4,602	3,636	4,716	1,570	6,286	5,000	1,364
20	Alma Equipment Repair	787	430	379	357	381	467	468	183	652	475	8
21	HVD Field Operations Expenses	236	239	248	238	230	238	349	120	468	363	125
22	HVD Operations	760	1,170	838	873	1,115	951	1,198	426	1,625	1,307	356
23	**High Voltage Distribution**	**18,981**	**21,720**	**20,217**	**22,218**	**25,832**	**21,794**	**27,204**	**9,608**	**36,812**	**30,075**	**8,281**
24	Meter Credits	(6,545)	(8,772)	(15,493)	(9,391)	(9,038)	(9,848)	(6,760)	(1,481)	(8,241)	(5,016)	4,832
25	Meter Tech & Mgmt Sys Support	1,019	1,085	1,199	1,063	1,182	1,110	1,080	401	1,481	1,290	180
26	Smart Energy MTC - Elec	8,986	9,020	8,756	9,611	9,488	9,172	9,462	3,230	12,691	9,690	517
27	Grid Management - Distr	6,363	6,134	5,514	4,646	4,137	5,359	4,705	1,378	6,083	4,164	(1,194)
28	Grid Automation	420	1,959	1,115	1,275	2,012	1,356	2,400	1,086	3,485	2,313	957
29	**Grid Ops & Restoration**	**10,242**	**9,426**	**1,092**	**7,204**	**7,782**	**7,149**	**10,886**	**4,613**	**15,499**	**12,441**	**5,292**
30	Electric Distribution Strategy	65	662	147	444	1,463	556	787	235	1,022	702	146
31	Training	10,807	10,993	12,076	11,107	9,798	10,956	11,211	5,263	16,474	13,200	2,244
32	Tools	2,358	1,753	1,384	1,256	1,223	1,595	1,223	615	1,838	1,751	156
33	Performance and Innovation	1,854	1,687	1,390	1,423	2,005	1,672	1,681	581	2,262	1,784	113
34	**Performance Innovation & Strategy**	**15,084**	**15,095**	**14,996**	**14,230**	**14,489**	**14,779**	**14,902**	**6,694**	**21,596**	**17,437**	**2,658**
35	**Management & Chargebacks**	**4,470**	**8,613**	**10,271**	**5,631**	**5,271**	**6,851**	**4,760**	**1,747**	**6,507**	**5,564**	**(1,287)**
36	**Work Management & Customer Delivery**	**5,787**	**8,652**	**5,109**	**2,290**	**1,691**	**4,706**	**1,596**	**591**	**2,187**	**1,775**	**(2,931)**
37	**Total Electric Operations**	**$ 249,730**	**$ 214,166**	**$ 276,611**	**$ 246,621**	**$ 283,019**	**$ 254,029**	**$ 291,758**	**$ 102,440**	**$ 394,198**	**$ 321,655**	**$ 67,626**

Reliability Roadmap (2025-2029)

As Amended for Case No. U-21870

June 1, 2025

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Executive Summary

Consumers Energy Company ("Consumers Energy" or the "Company") is driven by its purpose to achieve world-class performance delivering hometown service, measured by a triple bottom line—people, planet, and Michigan's prosperity. The triple bottom line balances the interests of customers with other stakeholders, and captures the broader societal impacts of the Company's activities.

People – The Company's purpose and passion is to make life better for the people of Michigan. Consumers Energy is committed to providing safe, reliable, and affordable electric service to its customers, and dedicated to providing a great customer experience—what Company employees refer to as providing 'hometown service.'

Planet – Consumers Energy's ambitious *Clean Energy Plan* will lead to achieving net zero carbon emissions by 2040 by eliminating the use of coal, bringing additional renewable energy resources on to the system, and working with customers to use energy more efficiently.

Consumers Energy is proud to be a leader in the clean energy transformation here in Michigan and across the country, as we forge a path toward a more sustainable energy future.

Michigan's Prosperity – Consumers Energy is committed to helping Michigan and its communities grow and thrive. A prosperous Michigan cannot exist without financially healthy utilities that provide safe, reliable, affordable, and increasingly cleaner energy. The significant funding the Company receives each year from investors and lenders makes possible the electric system infrastructure replacements and enhancements that benefit customers and the state of Michigan. Ensuring Michigan's prosperity also includes investing in local communities and supporting local nonprofits in addition to helping Michigan businesses grow and create jobs.

The Company has proudly served Michigan families and businesses since 1886, with more than 1.9 million electric customers across the state today. Consumers is committed to providing an electric distribution system that delivers safe, reliable, clean, and affordable electricity to customers today and in the future. To do that, the Company must address infrastructure risk in the near-term while adapting to meet evolving customer expectations and technology advancements.

The Company's commitment requires a distribution strategy based on four customer-focused outcomes, as follows:

- **Safe** – The Company will continue to design and maintain its distribution system to ensure the safety and security of customers and employees is maintained and ultimately enhanced.
- **Reliable and Resilient** –To ensure system *reliability* during predictable weather variations under normal operating conditions, the Company will improve its capabilities and visibility to proactively operate the system and better manage power quality to provide customers with a grid that remains stable and available. To ensure system *resiliency* and performance, the Company will harden the system where necessary to withstand abnormal conditions driven by increasingly severe and unpredictable weather and climate events.
- **Clean and Equitable** – The Company is building a system that will be modernized, smart, and capable of accommodating changing customer technology adoption patterns (such as electric vehicles and distributed energy resources) for all communities served, ensuring members of disadvantaged communities have equitable opportunities to participate. The Company will deliver reliability and resiliency equitably across all communities.

- **Competitive** – Provide affordable rates that will create value for customers by attracting and retaining businesses that provide jobs and economic opportunities, while ensuring every community —especially our most vulnerable—sees maximum energy investment according to its needs with minimal impact and energy burden.

The Michigan Public Service Commission ("MPSC" or the "Commission") first directed the Company to submit a five-year electric distribution investment plan in Case No. U-17990 in 2017.

On March 1, 2018, the Company delivered its first *Electric Distribution Infrastructure Investment Plan* ("EDIIP"), meeting the MPSC's directive. The Company filed a second EDIIP on June 30, 2021. On September 8, 2022, in Case No. U-20147, the Commission directed Consumers Energy to file an updated EDIIP by September 29, 2023, and provided updated guidance on new and revised content for inclusion in the plan. That updated EDIIP was filed, and branded as the "Reliability Roadmap," a term we now use when referring to this document.

After the 2021 EDIIP was filed, the Company received feedback from stakeholders, customers, and the MPSC on what would make future distribution plans more useful and engaging. The Reliability Roadmap concisely describes how the Company is anticipating the future needs of customers, and is developing an enhanced distribution strategy, informed by industry best practices from around the nation, to deliver cost-effective reliability and resilience benefits.

Concurrent with the filing of its 2025 electric rate case (Case No. U-21870), the Company is filing this updated version of the Reliability Roadmap.

Highlights of the Reliability Roadmap

- **An Overview of Emerging Scenarios and How They Impact Planning**: In the coming years, the electric distribution system faces two substantial, externally driven changes: **increasingly severe weather tied to climate change**, and **technological advances that affect how customers manage their electricity usage**. To prepare for this future, the Company modeled three different risk scenarios and impacts to the grid from electric vehicles and heat pump adoption, as well as weather impacts from extreme heat, wind, and thunderstorms driven by climate change. Through this detailed modeling and analysis, the Company presents the future all Michiganders must prepare for, and the Company's plan to deliver a reliable and resilient energy grid that addresses these threats.
- **An Overview of the Company's Capital Project Planning Process**: The Company's multi-faceted planning **process prioritizes and sequences investments to meet system needs and deliver safe, reliable electric service to all customers and communities in its service territory.** The Reliability Roadmap details how the process maximizes customer benefits and ensures those benefits are equitable throughout Michigan. This process will be used to provide reliable and resilient power based on the future climate and technology adoption scenarios.
- **Asset Management Approaches for Distribution Assets**: In the Reliability Roadmap, the Company provides a **detailed overview of its distribution assets, including the system health of each asset group, the risks each group faces, and the proactive steps** the Company is taking to ensure they perform as intended. Asset subclasses are grouped based on whether they primarily ensure the reliability of the grid, resiliency of the grid, or the safety of the public and Company employees. The five-year investment plans for each asset, based on the need to address identified risks and deliver improved performance, are outlined in this report.

- **Additional Topics**: This section of the Reliability Roadmap particularly outlines technological and analytical innovations related to the distribution system, resource needs attached to the Roadmap, and distribution-related economic development proposals to help Michigan compete for prospective new large industrial customer facilities.

Throughout the updated Reliability Roadmap, the Company presents its vision for the electric distribution system, analyzed through the lens of the system's current state, and outlines an investment plan to bridge from the current state to the desired future state.

The Company fundamentally believes that the nearly $8 billion of total investments outlined in this plan will deliver the safety, reliability, and resiliency benefits that customers expect. The Company plans to seek recovery for these investments.

Timely recovery of the costs of the investments described in this plan is essential to delivering the desired improvements in performance. Projects will not be executed in a timely manner if cost recovery lags or is denied. This trimming of capital would result in lower customer benefits and a lower-performing system whereby the Company continues to deliver its customers 3rd to 4th quartile reliability.

The Company looks forward to working with the MPSC, Staff, and the broader set of stakeholders as this plan is implemented and further improved over time. The Company plans to file updates to this plan, adding future years of investment and accounting for additional years of actual spending, with each subsequent rate case filing as an exhibit supporting test year investments.

A Note on Reliability Metrics

One of the important ways the Company measures how reliable we are delivering energy to our customers is to use the **System Average Interruption Duration Index ("SAIDI")**. The Federal Energy Regulatory Commission ("FERC") uses this reliability measure as do utilities to drive improvements in services. Originally developed by the Institute of Electrical and Electronics Engineers ("IEEE"), these metrics are significant and useful when evaluating and improving the quality of services delivered to customers.

The SAIDI Index has two components for measuring and reporting reliability:

1. The **System Average Interruption Frequency Index ("SAIFI")** tells us how frequently outages occur due to system condition, configuration, and related external conditions (e.g., weather patterns, forecasts, etc.). This measure is calculated by dividing the total number of customers interrupted by an outage by the total number of customers in the system.
    - Essentially, the SAIFI reveals *how often* the average customer has an interruption of power.
2. The **Customer Average Interruption Duration Index ("CAIDI")** tells us *how long* the interruptions last due to system conditions, resources available, number of interruptions, and storm restoration activities.
    - This measure is calculated by the total number of minutes customer energy is interrupted divided by the total number of customers whose service is interrupted.
    - CAIDI score reflects just the customers who were interrupted and measures the average time to restore services to those customers.

SAIDI results are calculated by multiplying **SAIFI** x **CAIDI**.

SAIDI is typically calculated excluding Major Event Days ("MEDs") to normalize performance data for unusually severe weather. The methodology for determining the level of storm activity to exclude in developing this chart is based on the *IEEE Guide for Electric Power Distribution Reliability Indices*[1].

However, the Company also tracks and reports its all-weather SAIDI, and discusses it at various points.

- The Company's SAIDI performance was 155 in the year 2024, which means the average amount of time a customer was without power that year was 155 minutes.

Understanding SAIDI is key to interpreting the Reliability Roadmap, which will quantify reliability in terms of SAIDI savings or outage minutes avoided because of specific investments.

As shown below in Figure 1, **Low Voltage Distribution** ("**LVD") Lines account for most of the Company's SAIDI minutes** due to the vast number of miles and territory served, exacerbated by its deterioration and exposure to trees and weather events. The Company's LVD system has 10 times more miles than its High Voltage Distribution ("HVD") system.

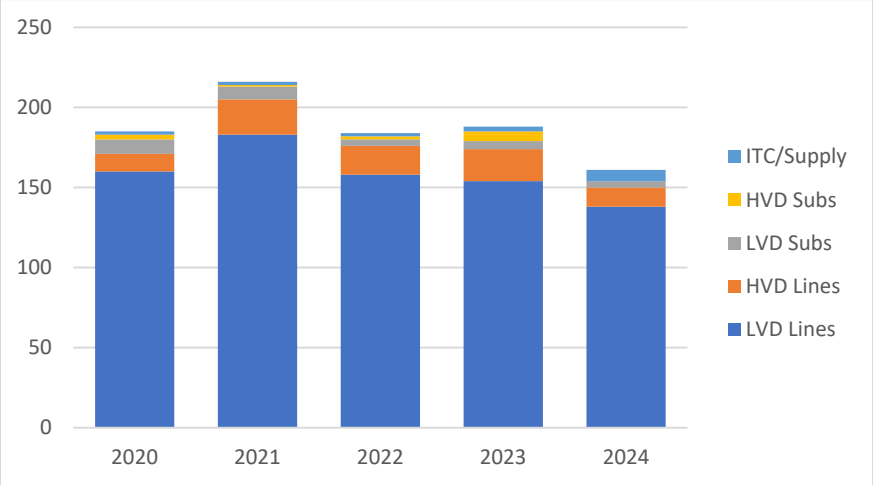
HVD Lines account for a smaller contribution to SAIDI—this is because SAIDI on HVD lines fell from 35.4 minutes in 2011 to just 12 minutes in 2024. This is attributable to increased investment in HVD assets over the last decade, in addition to the Company's aggressive and consistent *Forestry Line Clearing* program for HVD lines.

LVD and HVD substations account for a marginal amount of SAIDI minutes due to the redundancy built into the system, and maintenance and design choices that limit the probability of an outage. When substation failures do occur, the impact can affect tens of thousands of customers.

SAIDI minutes attributed to Michigan Electric Transmission Company ("METC"), the transmission provider (sometimes referred to by the name of METC's parent company **ITC**), also represent a minor amount of the overall SAIDI.

Figure 1

SAIDI MINUTES BY ASSET TYPE



[1] IEEE Standard 1366-2012 defines the methodology for calculating a MED. It is based on a statistical analysis of five sequential years of daily SAIDI values. In 2021, Consumers Energy adopted a refined methodology that transitions from a calendar day evaluation period to a rolling 24-hour evaluation period. This methodology better captures MEDs that straddle consecutive calendar days.

While the Reliability Roadmap accounts for growth in distributed energy resource penetration, the threats of extreme weather and existing system deterioration are too great to address through developing technologies.

Simply put, our customers and business need safe, affordable, and proven distribution assets to deliver the reliability we all deserve.

While distributed energy resources have an important role in the state's energy future, they are not the answer to achieving desired improvements in reliability and resiliency. To achieve the desired improvements in reliability and resiliency, the **Company must focus on hardening and improving the performance of its distribution system** through improving poles and wires.

- Effective increased investment in the LVD system is the key element needed to mitigate the worst effects of extreme weather and to begin to enable proactive planning for an increasingly electrified future.
- Enhancing the HVD system is also needed to maintain recent progress through proactively inspecting all assets repairing components on the HVD system to keep them within their useful lifecycle.

Vision for Our Grid

The Company is modernizing its electric distribution system to safely deliver clean, affordable, reliable power to customers throughout Michigan. **The goal is simple: fewer and shorter power outages for customers.** The vision for the grid is a blueprint for serving Michigan today and innovating to meet the challenges of the coming decades.

Customers depend on electricity to meet their everyday needs. They expect electricity to be delivered reliably on normal days with blue skies days under normal operating conditions, and the grid to be resilient in the face of increasingly extreme and unpredictable weather events.

Whether customers are using electricity to charge their electric vehicles, run their electric appliances, or are sending their on-site generation back to the grid, the Company must deliver reliable and resilient energy, and it is building the grid of the future to meet these customer needs.

Historic, once-in-a-lifetime storms are now the norm, resulting in more damaging storms that occur more frequently. The Company's analysis of weather patterns in recent years shows **that wind speeds and gusts continue to present a significant challenge for the distribution system**, as shown in Figures 9 and 10. While the Company is making an important transition in electric generation to address climate change and its impact on the weather, the same transformation is needed with the distribution system.

These risks will require a significant shift in our investment levels and strategy to mitigate the risks from extreme weather and improve the reliability of electric power.

In the face of these challenges, the Company has developed the Reliability Roadmap to respond to the immediate threats through proactive investments in automation, grid hardening, and aggressive maintenance and inspection of its system. This plan is the first step in developing the grid we expect, and lays out the scale of the challenges we face as a State.

The Reliability Roadmap, provided investment levels are fully approved, will serve as a bridge from our current grid to a grid that will be capable of achieving the following objectives:

1. **Delivering reliability performance into the 2nd quartile of nationwide utilities[2].**
2. **Delivering a grid where no single outage event will affect more than 100,000 customers.**
3. **Delivering a grid where no customer will be without power for more than 24 hours following an outage event.**

The Reliability Roadmap will significantly improve the Company's SAIDI performance over the next decade when compared to what would be delivered by recent electric rate case-approved levels of investment, providing a substantial improvement in performance over the Company's recent performance[3].

In the near term, the Company must address the timeworn infrastructure already on the system and proactively plan for increasingly severe weather.

- The Company is preparing to meet these challenges through increased inspections, preventative maintenance, and aggressive investment in hardening the grid through programs like strategic undergrounding and use of automated tools, such as automatic transfer recloser ("ATR") loops, to shorten the duration of outages.
- When storms do strike, the Company works to keep the public safe and uses all available tools to restore power as quickly as possible.

In the longer term, the grid will need capacity to meet customers' growing energy needs from electrification of transit, and other consumer products such as heat pumps and electrified appliances. With this growing dependance on the grid, the Company's focus on performance improvements will need to move beyond the traditional SAIDI excluding MED measurement to All-weather SAIDI. Measuring performance in all conditions will better represent our customers' experiences every day of the year, whether it is on a mild spring afternoon or after a sudden summer thunderstorm.

The deep electrification of the future will require investments to maintain reliable service and ensure every customer can power their homes, businesses, and vehicles.

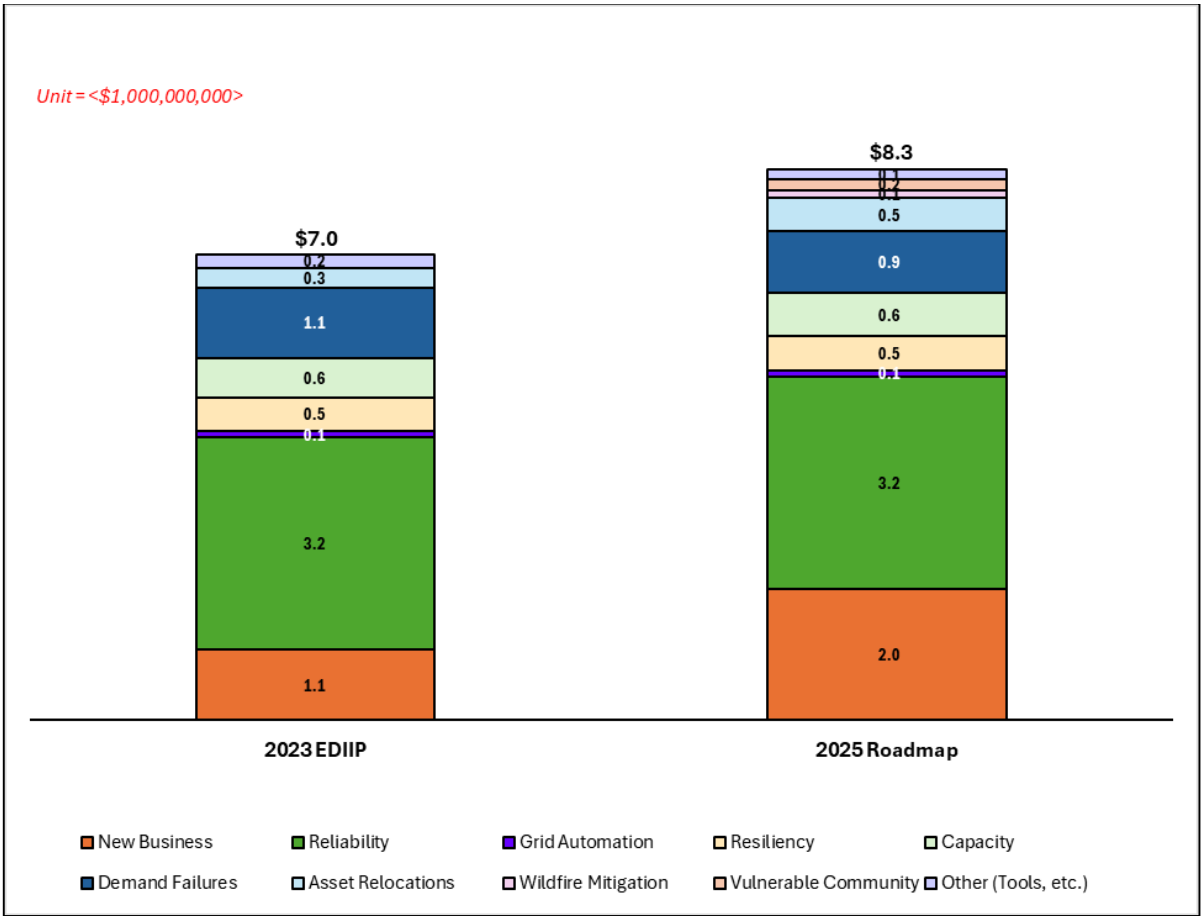
Investments in the next five years will total $8.3 billion—an increase of over $40 billion from what the Company outlined in its 2021 EDIIP. Operating and Maintenance ("O&M") increases to $2.5 billion over five years.

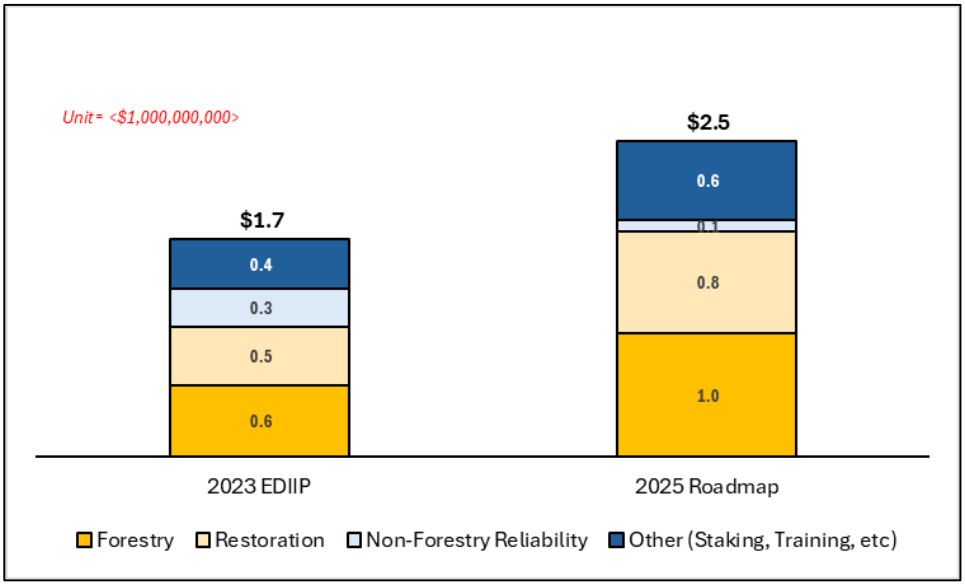
This investment is driven primarily by increased investments in Reliability, and to a smaller extent, by the Company's increased frequency of system inspections as well as the expectation that New Business, especially that tied to Economic Development, will continue to require investment in the system.

[2] 128 minutes for the 5-year average of IEEE Benchmark (2019-2023)
[3] 2018-2022 SAIDI excluding MED performance averaged 208 minutes

FIGURE 2

INVESTMENT FINANCIAL PLANS (2025-2029)





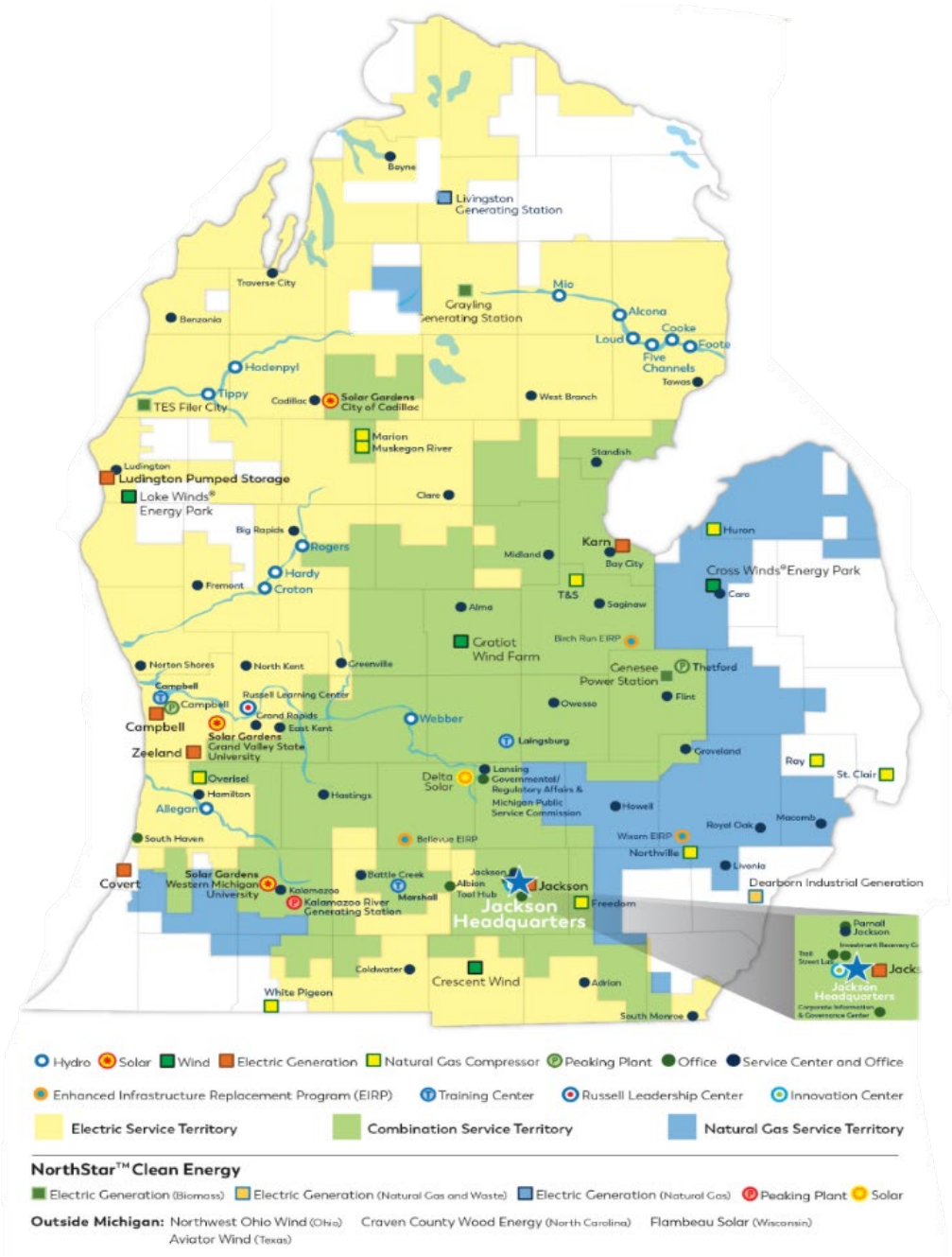
Distribution System Overview

Overview of Service Territory and System Components

The Company's electric distribution system is an essential part of Michigan's infrastructure, serving 1.9 million customers across more than 111,300 miles of distribution lines and 1,135 substations in the north, central, and western portions of Michigan from Monroe County to Mackinaw City, as shown in Figure 3.

FIGURE 3

CONSUMERS ENERGY SERVICE TERRITORY



The distribution system is functionally separated by operating voltage into HVD and LVD.

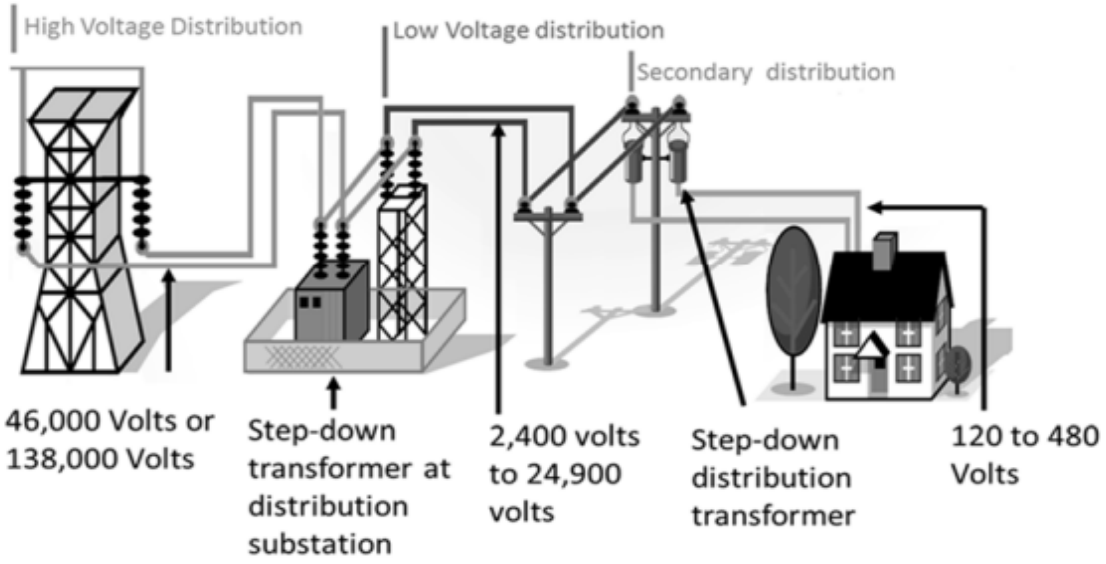
- **HVD operates at the highest voltages,** taking electricity from regional transmission companies, and transporting it across miles of lines, where it connects into the LVD system at 828 substations throughout the Company's service territory.
- **At LVD substations, high voltage is stepped down**, or reduced to lower voltages, onto the LVD system. LVD voltage is then further stepped down at secondary distribution transformers to secondary voltages (120 to 480 Volts), serving businesses and residences.

A *circuit* is a combination of electrical devices and hardware that are connected to and emanate from an LVD substation to deliver electricity to customers.

The Company's system has more than 2,000 LVD circuits.

- The primary distribution system begins at the distribution substation and ends at the distribution transformer.
- The secondary distribution system begins at the distribution transformer and ends at the customer, as shown below.

FIGURE 4
DISTRIBUTION SYSTEM COMPONENTS



LVD and Metro System

The LVD system is comprised of more than 107,000 total miles of lines, made up of approximately 61,000 miles of primary overhead and underground (carries electricity from substations to transformers), and 46,000 miles of secondary (carries electricity from distribution transformers to customers).

The LVD system consists of 13 different voltages. More detail on these assets and the Company's strategy for ensuring these assets operate as intended is described in more detail in the LVD Lines under the Overview of Asset Management section.

The LVD system also includes a distinct component called **the *Metropolitan Underground system (Metro)*, which provides underground distribution service** in the downtown areas of six cities in the Company's service territory: Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw.

- The Metro distribution infrastructure is installed underground to promote public safety by keeping energized infrastructure away from densely populated areas and protecting the aesthetics of downtown areas.
- The Company's Metro planning group focuses solely on these key downtown areas, reflecting the Company's commitment to investment in Michigan by dedicating specific attention to these areas.

More detail on the Metro assets and the Company's strategy for ensuring these assets operate as intended is described in more detail in the Metro chapter under the Overview of Asset Management section.

HVD System and Substations

The HVD system comprises all assets from the point of interconnection with the transmission provider through the point at which LVD lines exit LVD substations.

It is composed of three distinct asset groups:

1. HVD substations
2. HVD lines
3. LVD substations, which are organized as part of the HVD system to leverage substation planning, engineering expertise, and large equipment resourcing in a consistent and efficient manner.

The Company's substation network consists of 1,135 substations.

- The HVD substation network consists of 144 HVD substations and 163 dedicated customer substations in addition to the LVD and general distribution substations mentioned earlier. Additionally, there are five Company-owned substations providing wholesale distribution services to rural co-op and municipal systems.
- Beyond the Company's substations, there are also 35 customer-owned dedicated substations, and 30 customer-owned substations providing wholesale distribution services to rural co-op and municipal systems. Although the Company does not own these, they are still connected to the Company's system.

More detail on these assets and the Company's strategy for ensuring they operate as intended is described in the HVD Lines and Substations chapters under the Overview of Asset Management section.

The HVD system is comprised of approximately 4,600 total miles, with about 4,400 of those miles being 46 kV and 69 kV overhead lines, and 19 miles being 46 kV underground lines, and approximately 200 miles being 138 kV overhead lines, and 4 miles being 138 kV underground lines.

System Condition

In accordance with the Commission's September 2022 Order in Case No. U-20147, the Company has benchmarked reliability performance against peer utilities, and the results of this are shown in Figure 5.

FIGURE 5

RELIABILITY BENCHMARKING AGAINST PEER UTILITIES



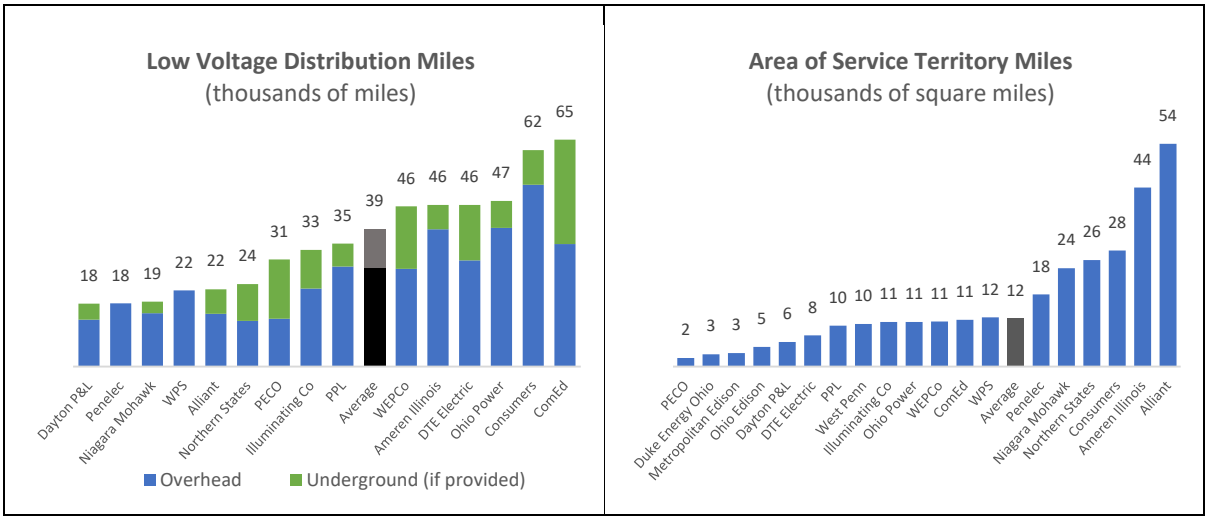
This benchmarking shows that, when normalized for capital investment per line mile, the Company provides average reliability, but outages tend to last longer than those of peers.

This long duration can, in part, be contributed to the size of the Company's service territory and the large number of overhead line miles used to serve its 1.9 million customers.

On average, the Company's employees maintain a system that is approximately 60% larger than its peers on both a line mile and 140% larger on a square mileage basis as depicted in Figure 6 below.

FIGURE 6

COMPARISON OF SERVICE TERRITORIES



The Company's service area has expanded to serve many new communities and businesses in Michigan throughout more than a century of distributing electricity. Much of this infrastructure—lines, poles, pole top equipment, and substations, among other assets—now needs replacement or upgrades to improve efficiency and reliability of the grid.

It is important to emphasize that age is *not* the only indicator of system health, nor is it the only driver of when an asset must be replaced—the pole shown below in Figure 7 is 86 years old and shows fewer reliability issues than some younger poles in the Company's service territory.

The Company thinks holistically about how to best serve customers reliably, and this means assets are replaced based on overall deterioration.

That said, age and deterioration are generally correlated, and the advanced age of many assets provides some indication of the general systemwide need for asset replacement.

Ultimately, the Company only replaces assets that are actually deteriorated based on inspection or performing poorly based on reliability data. The Company does not replace assets simply because of their age.

FIGURE 7
1936 VINTAGE 35-FOOT LVD POLE



The deterioration and health of assets vary based on field conditions (e.g., soil, weather, slope, wind patterns, etc.), location, and materials used by the manufacturer (e.g., wood type, porcelain, polymer, interrupting media, etc.). For example, poles deteriorate at a faster rate in wet soil conditions than in dry non-acidic soil conditions, and porcelain is more susceptible to freeze or thaw conditions than polymer.

The Company proactively replaces, rebuilds or rehabilitates assets before failure, when inspections or performance data indicate the asset is in a state of deterioration. Of course, when assets fail in the field and cause outages, the Company often replaces them as well, if doing so is more reasonable than fixing the broken asset.

Ultimately, the assets replaced, rebuilt or rehabilitated are done so to the specifications needed to meet future reliability and capacity needs of the grid.

The Company is enhancing its distribution asset management capabilities, as discussed in the Asset Investment Planning Optimization section, to address this issue.

Even as the Company's distribution asset management capabilities remain under development, the Company has developed new analytical approaches to assess system deterioration, particularly by using system performance data during adverse weather conditions.

Scenarios and Future Impacts to the Distribution System

Drivers of Change

Increasingly Severe Weather

The Great Lakes region is not immune to climate change; the Company has been monitoring the impacts of the changing climate and weather on its operations for years, and has been crafting an approach to remain resilient as new climate patterns emerge.

In 2022, the Company published its Climate Risk, Vulnerability and Resiliency report that identifies its susceptibility to the potential adverse effects of climate change, and discusses the Company's governance structures and proactive efforts to remain resilient to the potential impacts of climate change on its infrastructure.

The analysis completed through the development of this plan examines similar risks, including wind gusts, extreme heat, wildfires, and severe storms.

For much of history, the climate has gone through small changes, but the climate and associated weather patterns are now changing at an accelerated rate.

In recent years, the Company has experienced repeated instances of strong winds causing large-scale outages; since 2015, the Company has seen a general increase in the number of MEDs per year, as shown in Figure 8 below.

FIGURE 8
MAJOR EVENT DAYS BY YEAR

Year	MED Days
2015	3
2016	5
2017	8
2018	7
2019	9
2020	8
2021	11
2022	9
2023	11
2024	10

In general, the Company's service territory has experienced increased high and sustained wind speeds as well as wind gusts.

The Company monitors wind speed data from many National Weather Service stations throughout its service territory. Figures 9 and 10 below illustrate the hours each year of sustained high wind speeds and of high wind gusts.

FIGURE 9

STATION HOURS EXCEEDING HIGH WIND SPEED THRESHOLDS

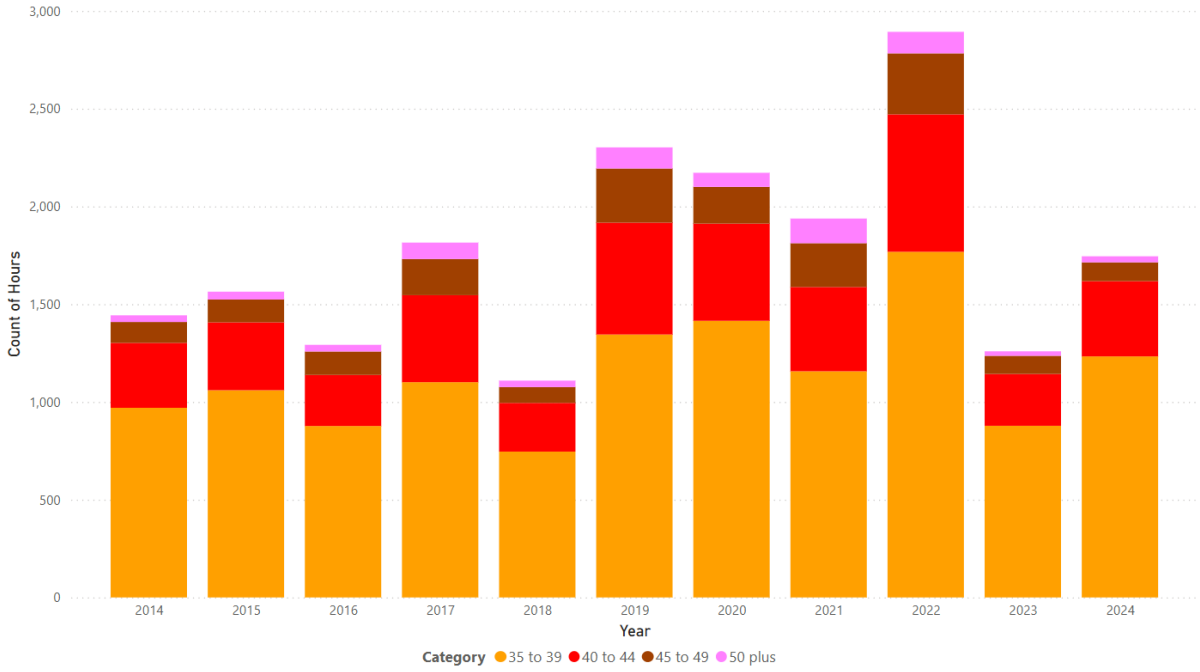
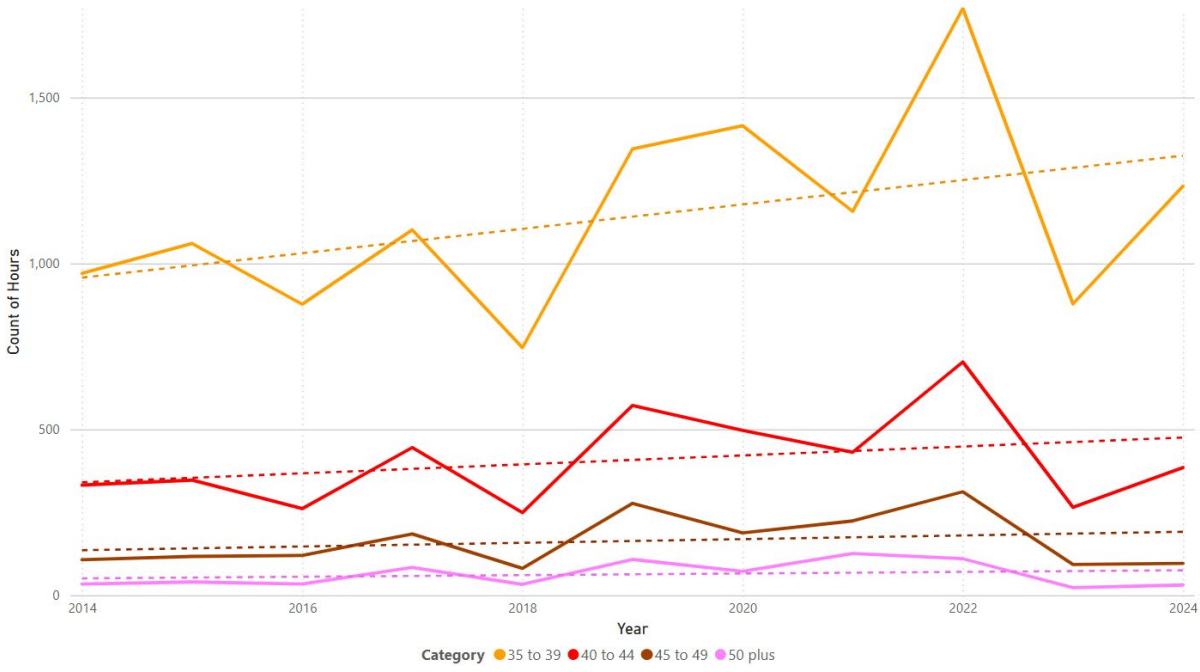


FIGURE 10

STATION HOURS EXCEEDING HIGH GUST THRESHOLDS

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The number of large-scale storm outages, while increasing, is still consistent with normal weather variability. However, those severe weather events are likely to become more frequent as climate change increases the frequency of storms that cause high winds.

Climate change will also increase the frequency of extreme heat conditions, which tend to increase loading on the grid as customers use more air conditioning.

In assessing its investment plans, the Company is considering the likely resiliency risks from more frequent severe weather conditions, and what investments are needed to harden against those risks.

The Company is also considering how to best plan for increased load on circuits as rising temperatures result in more cooling degree days.

Technological Innovation

In the future, climate policies and targets related to decarbonization will likely lead to increased adoption of technologies that *will require* more electricity, although to date these new technologies have not experienced widespread penetration in the Company's electric service territory:

- Solar distributed generation ("DG") has an installed capacity of 135 MW across all customer types[4].
- Electric Vehicles ("EVs") currently represent less than 1% of total vehicles.
- Electric heat pumps have been adopted by 2% of total households.

Going forward, the Company expects increased adoption of these technologies, driving load growth that will have wide-ranging impacts for the distribution system.

In assessing its investment plans, the Company is considering whether individual circuits can accommodate rising peak demands, and whether they can accommodate increasing amounts of solar DG. This will inform the need for standard capacity improvements on the system but may also point to increased use of non-wire solutions to shave peak load or Distributed Energy Resource ("DER") management to interface with solar DG.

Scenario Analysis

As outlined in the previous section, the Company has identified severe weather and technological adoptions as the primary drivers of change on the distribution system, representing the most pressing challenges to the future grid.

To further refine this broad assessment of threats to grid reliability, the Company pursued a detailed analysis to predict the circuit-level impacts from severe weather and customer technology adoption.

Beginning in 2022, the Company developed a strategy to develop a resilient and reliability grid. This included creating a comprehensive vision of the future of the grid and ensuring near-term investments meet the needs and mitigate the risks anticipated in the future. This process sought to answer two key questions:

- What is the holistic set of challenges that the future grid must address?
- What are the most significant potential grid impacts?

[4] See the Company's Form EIA-861 filing.

Key Impacts Modeled

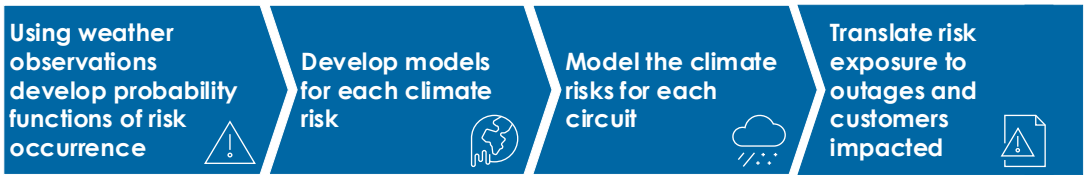
The impact of the two key drivers (climate risks and customer technology adoption) were modeled on the distribution grid.

- **Climate risks** included the highest-impact hazards for the Company's service territory: storm conditions, ice conditions, and extreme heat.
- **Customer technology adoption** included the impacts to the grid from projected solar distributed generation, heat pumps, and electric vehicles as well as organic load growth driven by population changes.

A climate model was used to identify climate risks specific to the Company's service territory and translates exposure to outages as detailed in Figure 11 below.

This model used more than 25 million weather observations from across the lower peninsula of Michigan to develop probabilities of the frequency of risk occurrence. These models predict the specific climate risks to individual circuits and translate the impact of these risks in terms of outages and customers impacted.

FIGURE 11
CLIMATE MODEL METHODOLOGY[5]



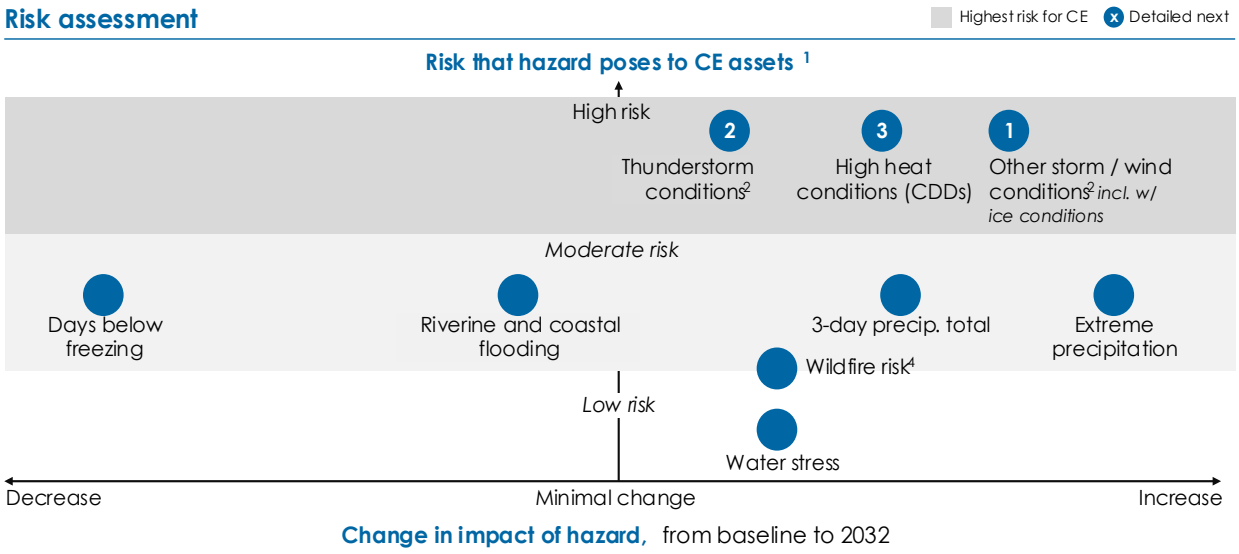
Actions	Using over 25 million weather observations from across the lower peninsula, we developed probability functions to characterize the frequency of risk occurrence	Built specific analytical models to identify storms, extreme heat and freezing rain in climate projection data using the historical probabilities	Using 620 GB of data and AWS cloud computation, we modeled key climate risks (storms, freezing rain, extreme heat) per circuit at daily or hourly resolution across scenarios	Grouped circuits according to headquarters to understand historical incidents; mapped climate risk exposure to incidents; projected changes in exposure to incident changes

After evaluating numerous weather-related hazards shown in Figure 12 below, the modeling focused on the highest-impact hazards to Company assets and grid integrity including:

- **Thunderstorm conditions**, featuring extreme wind and precipitation, can impact tree and pole stability and often lead to outages. These storms are fueled by warm air and are thus most frequently observed in summer months.
- **Other storm conditions**, featuring extreme wind and precipitation, including in some cases the potential for damaging icing and freezing rain. Like thunderstorms, these storms can impact tree and pole stability, leading to outages but are observed year-round.
- **High heat conditions** defined as days above 86 degrees Fahrenheit, which may simultaneously increase customer demand and reduce the efficiency of the distribution grid (e.g., line losses).

[5] Climate and Technical Adoption modeling was performed by an independent third-party consultant.

FIGURE 12
CLIMATE RISKS EVALUATED



1. The risk to CE assets was determined subjectively based on whether direct asset damage was likely to occur at CE asset locations for that specific hazard and if so, would the damage be disruptive
2. Storm conditions are based on the precipitation, wind and temperature conditions of declared storms. Winter storms include ice conditions
3. Ice conditions refer to the proxy for freezing rain conditions based on extreme heat and extreme precipitation increases. Ice storms are captured under Storm / wind conditions.
4. The risk of wildfires in Michigan is not zero, but it is relatively lower than many other states such as California.

While other risks (e.g., riverine flooding) are present, their more limited spatial footprint makes them less likely to drive frequent widespread outages.

Emergent risks, such as wildfires, and extreme precipitation were analyzed in this modeling and deemed less of an immediate risk to Company assets compared to the three modeled risks.

However, events like the June 2023 fire in Northern Michigan; the August 2023 wildfire in Maui; and other fires since then in the U.S. illustrate the need to more proactively address wildfire risk and mitigate that risk. **As a result, the Company developed a wildfire risk mitigation plan in 2024, discussed later in this report.**

In addition to climate modeling, the modeling also analyzed **the impact of new technology** adoption such as solar DG, EVs, and heat pumps, and how they will impact electric demand and corresponding grid capacity needs.

- The modeling forecasted the uptake of these new technologies to develop a discrete choice model based on customer demographics to **determine customer likelihood of acquiring these technologies** on each circuit and their usage profiles as detailed in Figure 13 below.
- With these two factors developed, the modeling calculated total load increase on the grid for each driver to determine which hours, months, and seasons have the highest load increases and how the increases evolve over time.

FIGURE 13

TECHNOLOGY ADOPTION MODEL METHODOLOGY



Actions	Forecasted service - territory-wide uptake utilizing adoption models, taking into account economic and non-economic adoption	Developed a discrete choice model that uses customer demographics to determine the likelihood of a customer acquiring each driver	Applied annual usage profiles to each driver to see the hourly impacts each driver has on the circuits load, as well as their cumulative impact	Looked at the cumulative impact to load from each driver to determine which hours, months, seasons have the highest load increases as well as tracking those increases over time

Identified Scenarios

The Company identified three scenarios governing the future through 2050. Each scenario assumes a given set of external trends encompassing both the rate of climate change and the rate of customer adoption of solar DG, electric heat pumps, and EVs.

The three scenarios are referred to as *Decelerated Transition* ("DT"), *Continued Momentum* ("CM"), and *Accelerated Transition* ("AT").

Federal policy, particularly as defined in the *Inflation Reduction Act of 2022* ("IRA"), makes a clear connection between the deployment and uptake of low-carbon technologies and achieving certain climate change targets. Correspondingly, these scenarios assume that uptake of low-carbon technologies will have a direct correlation with climate change outcomes.

In general, climate change will result in more severe weather and extreme heat, which creates increased reliability and resiliency challenges for the distribution system. Increased adoption of low-carbon technologies can also increase demand on the grid, at least in certain locations, which can also impact what investments are needed.

1. Decelerated Transition Scenario

The DT scenario assumes existing government climate policies, and other climate-related targets, are not fully implemented, and public action to mitigate climate risks slows down from current levels or even begins to reverse.

- In this scenario, uptake of low-carbon technologies is significantly delayed, with penetration levels remaining low overall. This scenario results in a temperature increase of ~2.5°C by 2050 compared to pre-industrial levels, with attendant increases in severe weather.

The Company's analysis generally assumes the DT scenario is the least likely, given the direction of climate policy and climate-related targets, although the Company has considered the impacts of this scenario to establish a worst-case baseline and conducted little analysis on it due to its improbability.

2. Continued Momentum Scenario

The CM scenario assumes climate policies already existing in law are fully executed, but that no new policies are implemented.

- In this scenario, public adoption of solar DG, heat pumps, and EVs broadly continue in their current post-IRA trends. This scenario results in a temperature increase of ~2.0°C by 2050 compared to pre-industrial levels; such a temperature increase still results in increased severe weather and increased resiliency risks to the grid, albeit not as large as under the DT scenario.
- The CM scenario makes further assumptions about electrification and decarbonization nationwide or worldwide. In particular, the CM scenario assumes the U.S. power grid becomes 80%-90% decarbonized by the late 2030s; that at least some heavy industry is deeply decarbonized in developed countries; that carbon capture and sequestration remains marginal; and that the U.S. and other developed economies transition to EV-majority vehicle sales during the period from 2030 to 2040.

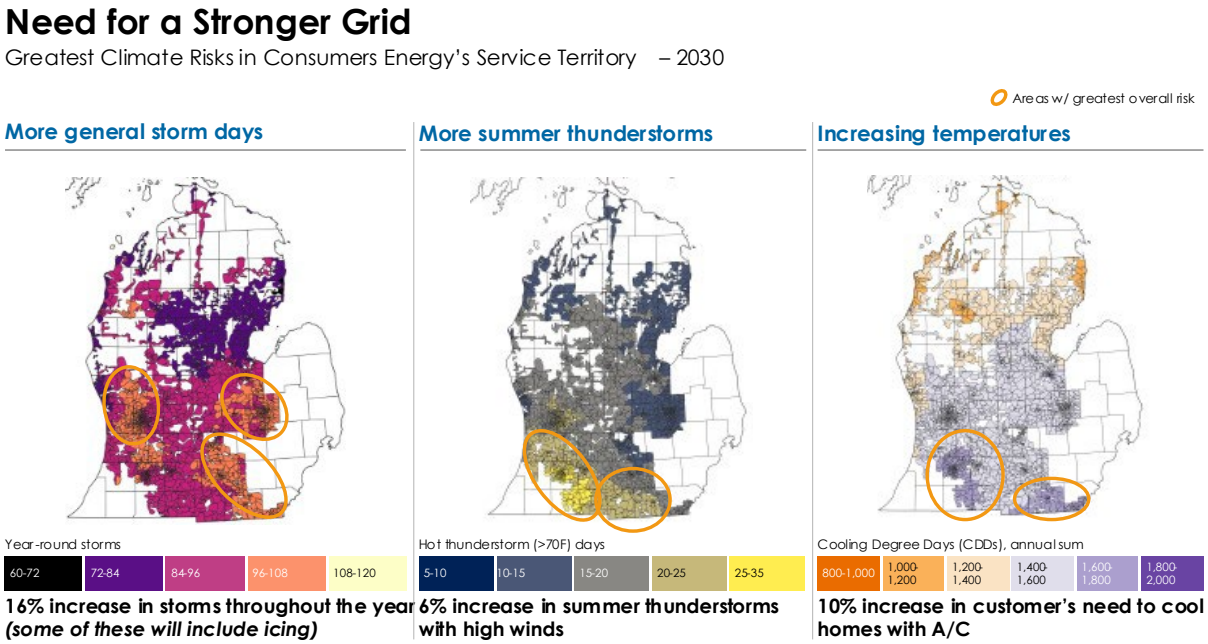
Without mitigation, the CM scenario projects that the Company's system would experience a 12% increase in the number of MED outages by 2030, and a 24% increase by 2050, due to increasingly severe weather.

Further, while the CM scenario only projects that 2% of the Company's circuits would be at risk of exceeding load constraints by 2030, this increases to 32% of circuits by 2050 as low-carbon technological penetration increases.

These increasing risks under the CM scenario are illustrated by the following maps that represent the projected situation in 2030, including where each risk is most acute.

FIGURE 14

CLIMATE RISK IN CONSUMERS ENERGY SERVICE TERRITORY



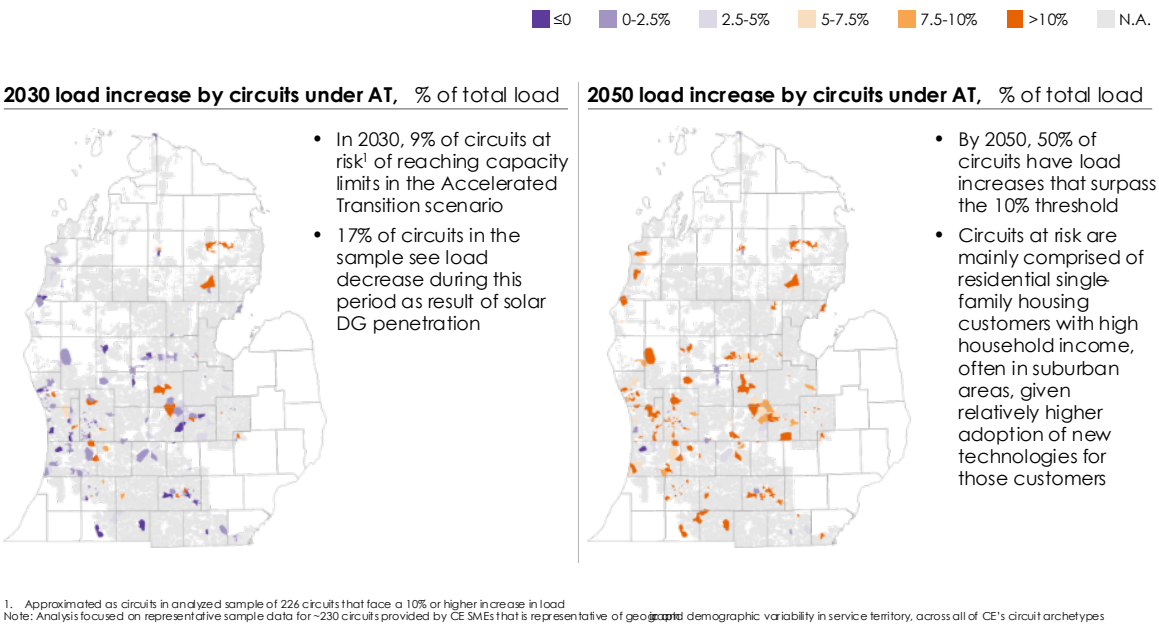
3. Accelerated Transition Scenario

The AT scenario assumes that, due to faster cost declines and increased financial incentives, solar DG and EVs are adopted even faster than on current trends, although heat pump adoption will remain stable as natural gas remains inexpensive in Michigan.

- In this scenario, temperatures increase by ~1.5°C by 2050 compared to pre-industrial levels, in line with targets set in the 2015 Paris Agreement and compatible with achieving global net-zero carbon dioxide emissions by 2050. This scenario minimizes the increased resiliency risk to the grid due to increasing severe weather, although there will still be increased resiliency risk compared to today.
- Like the CM scenario, the AT scenario makes several further assumptions about electrification and decarbonization nationwide and worldwide. The AT scenario assumes the U.S. power grid is fully decarbonized by 2035, and the global power system by 2040. It also assumes 90% of heavy industry is low emissions by 2050; that carbon capture and sequestration becomes widespread; and that no internal combustion cars are sold anywhere in the world after 2035.
- The AT scenario includes the greatest increase in risk of circuit overloads due to adoption of low-carbon technology. Under this scenario, by 2030 9% of circuits will face this risk based on a representative sample of over 10% of the Company's circuits. This risk only compounds after 2030, and by 2050 would apply to 50% of the Company's circuits.

FIGURE 15

ACCELERATED TRANSITION LOAD INCREASES



1. Approximated as circuits in analyzed sample of 226 circuits that face a 10% or higher increase in load
Note: Analysis focused on representative sample data for ~230 circuits provided by CE SMEs that is representative of geographic and demographic variability in service territory, across all of CE's circuit archetypes

Of these scenarios, the Company chose CM and AT scenarios for further analysis given their closer alignment to likely post-IRA pathways. As a significant fall below CM, DT was viewed as an unlikely worst-case scenario for heightened climate risk. For prioritized scenarios, load impacts of solar DG, heat pumps, and EVs were considered alongside organic load growth.

Impacts of Scenarios on the Distribution System

The modeled evolution of climate risks and customer technology adoption, and their impacts at an individual distribution circuit level, present the following types of grid challenges to the Company's distribution system:

1. **While there is long-term uncertainty around the pace of emissions and climate change, there is more near-term certainty around increases in warming and weather hazards.** In short, **climate change represents the most urgent threat** to the reliability of the Company's distribution system and must be addressed immediately.
2. **Without shifts in the Company's current investment strategy, outages from severe weather are likely to increase 10-15% relative to 2020 levels by the early 2030s regardless of climate policy actions**. In assessing its investment plans, the Company is considering the likely resiliency risks from more frequent strong wind and storms, and what investments are needed to harden against those risks.
3. **The largest relative increase in other storm (non-thunderstorm) days is likely to be in the winter** when outages are typically most difficult to restore.
4. **Depending on the trajectory of EV, heat pump, and solar DG adoption, the Company could see up to 1-10% of circuits reach at risk load levels by 2030[6].** By 2050, as many as 40% of circuits could see load more than 10% higher than current peaks.
5. **The long-term future of Michigan's energy system is a more electrified and distributed one.** There is uncertainty, however, over the pace at which this will occur, and therefore when challenges associated with peak loads and DER adoption will materialize. Understanding the pace of customer technology adoption will be critical for pre-empting peak demand challenges.
6. **With heightened heat pump adoption, there's the potential for Consumers Energy to shift from a summer to a winter peaking system.** The expected increase in winter load has implications for broader network design and planning (e.g., generation, equipment standards, etc.)

Challenges from Climate Risks

The magnitude of climate risk impacts likely to be seen in the Company's service territory represents a significant step-up from current levels as detailed in Figure 16 below.

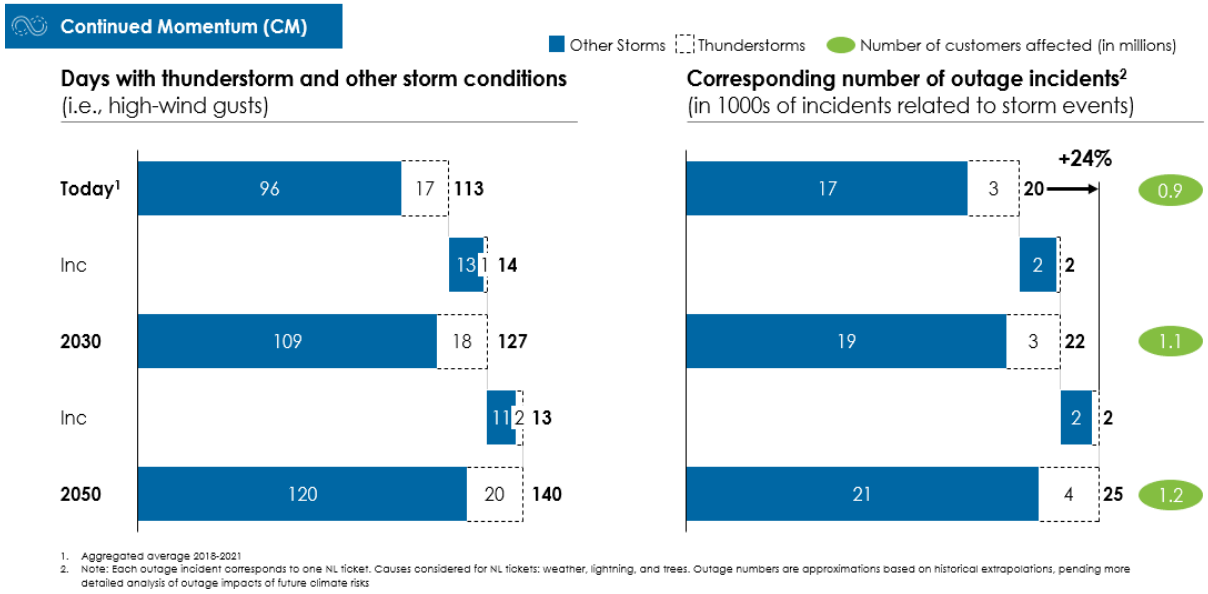
Key climate risks—storms with extreme wind, as well as high heat conditions—are projected to increase in the Company's service territory by up to 25% (20 storm days by 2030), and up to 45% (30 days by 2050).

These changes in climate conditions will compound with weather effects the Company has already seen over the last 15 years, such as a 9% or 7-day increase in storms and could lead to a 12% increase in the number of MED outages by 2030, absent countermeasures.

[6] Defined as increases more than 10% higher than current peak load, a typical threshold evaluated by CE.

Figure 16

PROJECTED DAYS WITH THUNDERSTORMS AND NUMBER OF OUTAGE INCIDENTS UNDER CONTINUED MOMENTUM

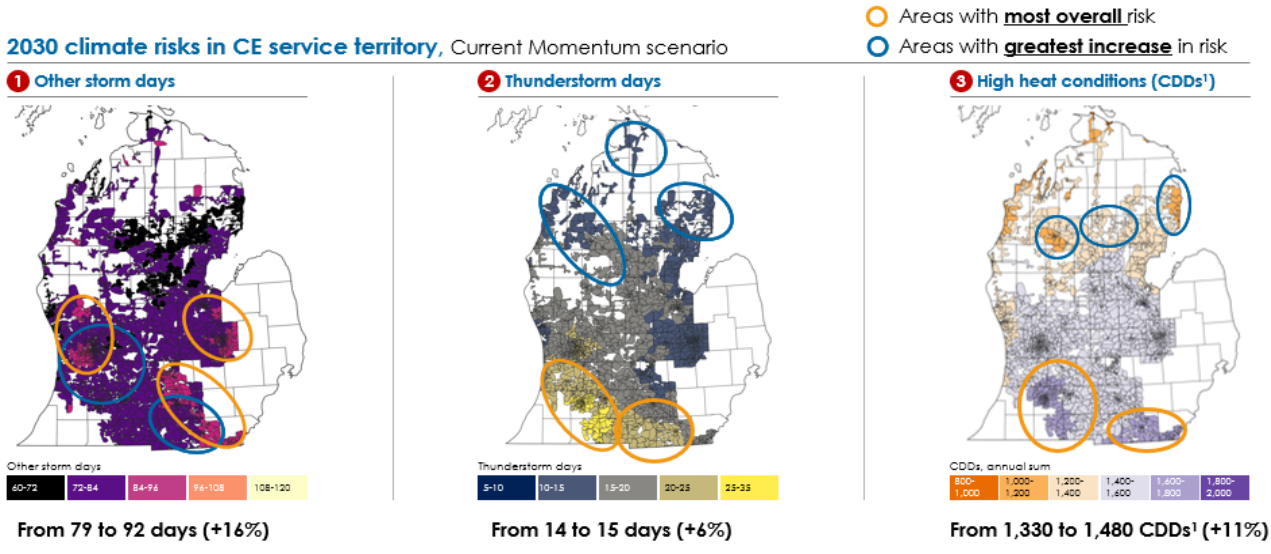


Risks are forecasted to materialize predominantly in northwestern and southern parts of the Company's service territory—by 2030, these areas see strong increases in thunderstorms (+30% / 3 days), other storms (+25% / 20 days) and high-heat conditions (+30% / 300 CDDs).

Climate risks and load impacts will significantly shape the grid environment—several areas in the Company's service territory will see their largest relative increase in climate risk as soon as in the next 7 years (e.g., 50% of increase / 20 days in storm days in Kalamazoo area may materialize by 2030), with another 50% increase realized by 2050.

Figure 17

2030 CLIMATE RISKS IN CONSUMER ENERGY SERVICE TERRITORY



Key changes, on average (maximum changes are greater) include:

Climate event	Today	Increase by 2030	Increase by 2050
Thunderstorms	17 days	~1 day (+4%)	~3 days (+17%)
Other storms	79 days	~13 days (+17%)	~21 days (+27%)
Cooling Degree Days	~1,330 CDDs	~147 CDDs (+11%)	~368 CDDs (+28%)
Days above 86°F	38 days	~12 days (+31%)	~26 days (+70%)

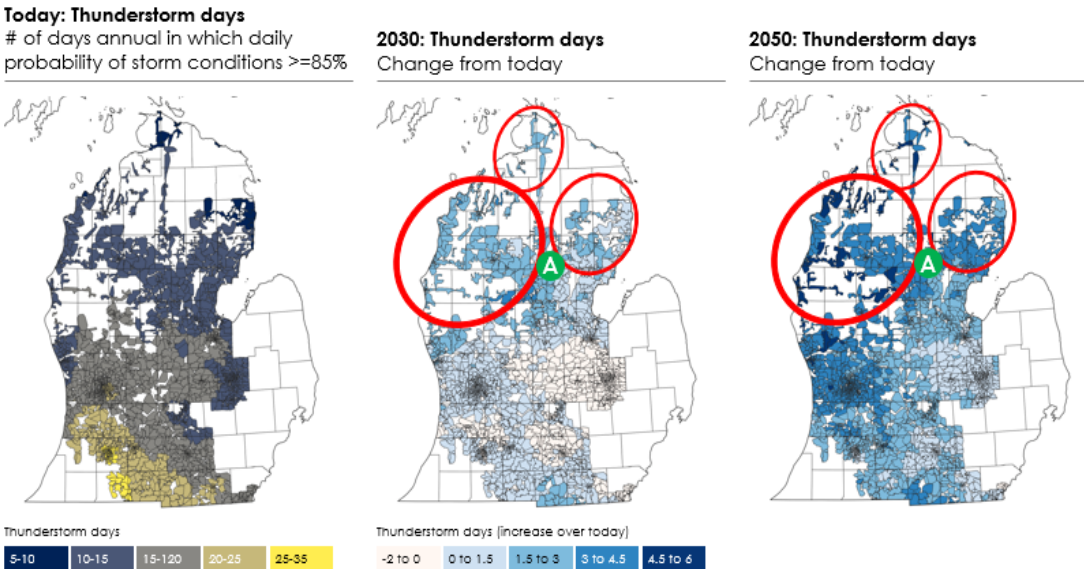
Figure 18 below depicts shifts in thunderstorm risk and the evolution from today's annual number of days with a daily probability of storm conditions greater than 85%.

Thunderstorms, defined as *events with maximum wind speeds greater than 30 mph and temperatures greater than 70°F,* are more prevalent today in southern and lower central Michigan. These thunderstorms are most associated with the high wind speeds that can disrupt the grid.

Central, northern, and eastern Michigan may experience a 30-60% increase in thunderstorm risk by 2050 (indicated by the letter A in the chart below). By 2050, 660 circuits may see a >20% increase in likely thunderstorm days.

Figure 18

2030 AND 2050 THUNDERSTORMS INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



Other storm annual frequency has been studied using the number of days annually, in which daily probability of storm conditions are greater than 50%. Storms and connected occurrence of wind, have some of the highest damage potential for the Company's grid.

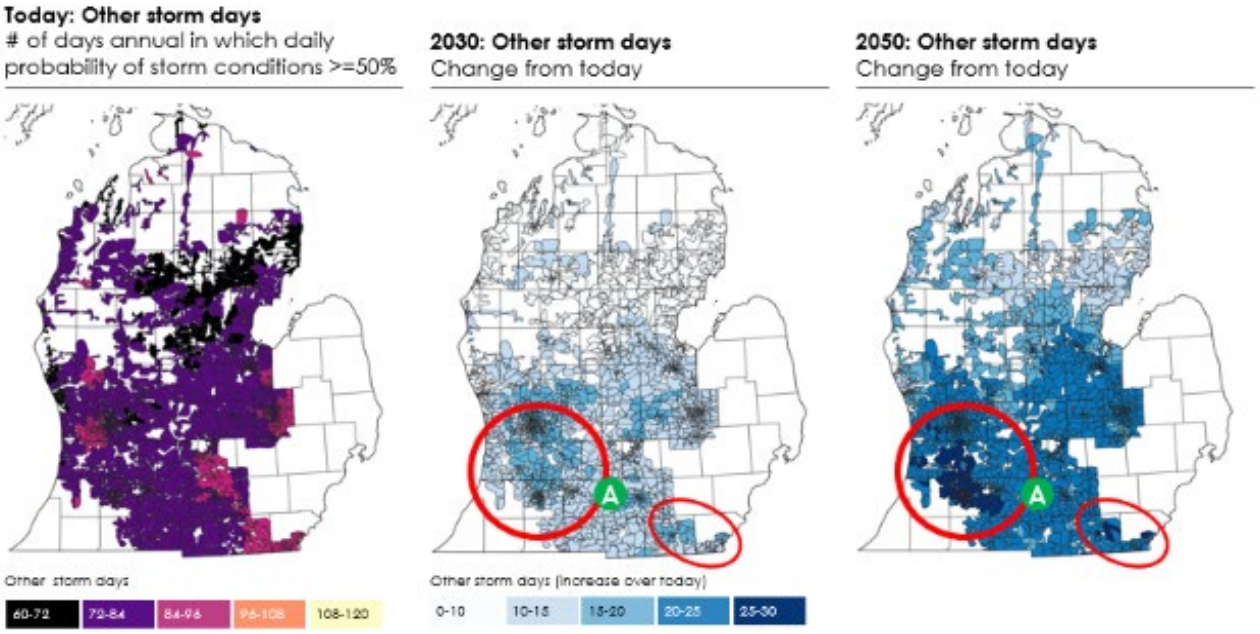
Almost all circuits (97%) are likely to experience at least a 20% increase in storm days by 2050 under a CM scenario, and nearly 20% of circuits are likely to see a 30% increase in storm days.

- As highlighted in red circles with a green letter A in Figure 19 below, **the Grand Rapids and Kalamazoo regions may see particularly large increases** with 25-30 additional potential storm days throughout the year by 2050.

As warming continues, these storms are increasingly likely to be accompanied by damaging freezing rain conditions like the catastrophic storm that swept through Michigan in February 2023, knocking out power to over 700,000 homes and businesses.

Figure 19

2030 AND 2050 STORM INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



Multiple measures of high heat conditions indicate a likely increase.

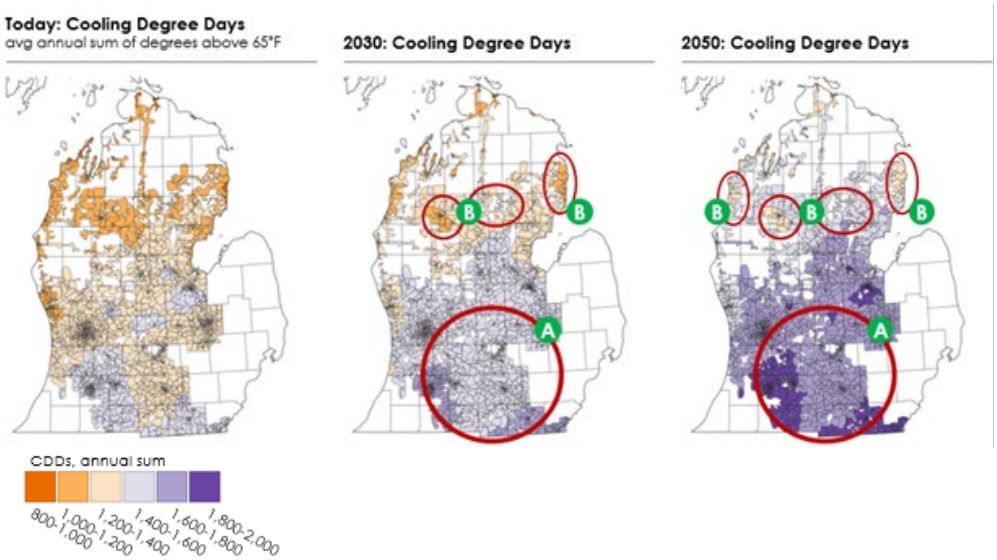
Increases in high heat conditions can result in lower line efficiency and higher customer loads, potentially bringing circuits closer to their rated capacity limits.

The largest absolute increases in cooling degree days, a benchmark used to measure broader heating, are in the southern Michigan circuits, which could see as much as 1,900 annual CDDs by 2050 (denoted by A in the Figure 20 below), an increase of 25% above today's conditions.

North central Michigan (denoted by B in the Figure 20 below) may see an even larger relative increase of as much as 33% in annual CDDs, up to 1,400 CDDs.

Figure 20

2030 AND 2050 COOLING DEGREE DAY INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



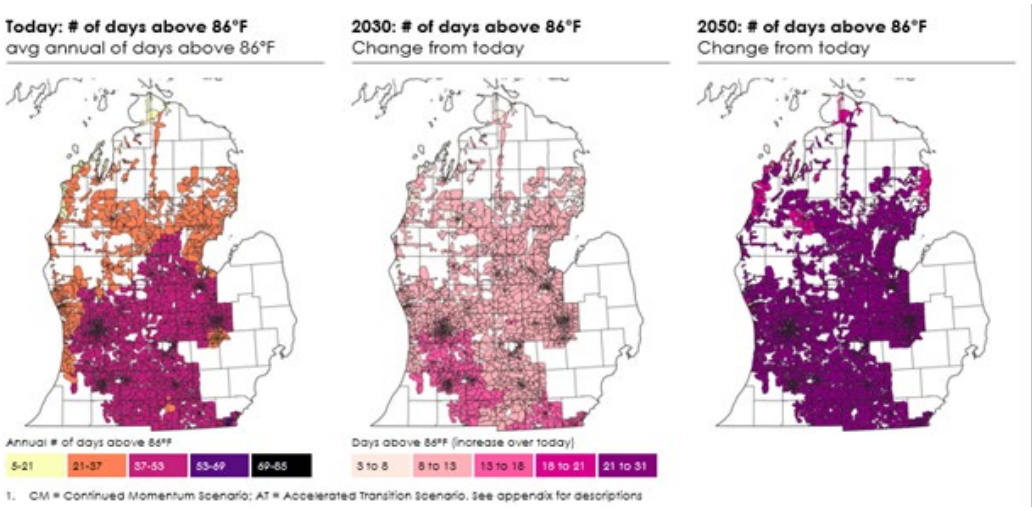
Days above 86°F, another measure of high heat conditions, can lead to reduced line efficiency of 7% and higher customer loads due to increased air conditioning usage, potentially bringing circuits closer to their rated capacity limits.

By 2050, almost all of Michigan is likely to experience more than 20 days of additional high heat. With some regions already experiencing ~50 days of high-likely air conditioning usage and line loss, this is a 40% increase from current levels.

The graph below in Figure 21 examines the average annual number of days with temperatures above 86°F in Consumers Energy's service territory.

Figure 21

2030 AND 2050 DAYS ABOVE 86 DEGREES INCREASE IN CONSUMERS ENERGY SERVICE TERRITORY



Taken together, these insights can help focus grid-hardening investments today to reduce the risk of future outages.

Challenges from Customer Technology Adoption

The magnitude of modeled customer technology adoption represents a significant step-up from levels seen today.

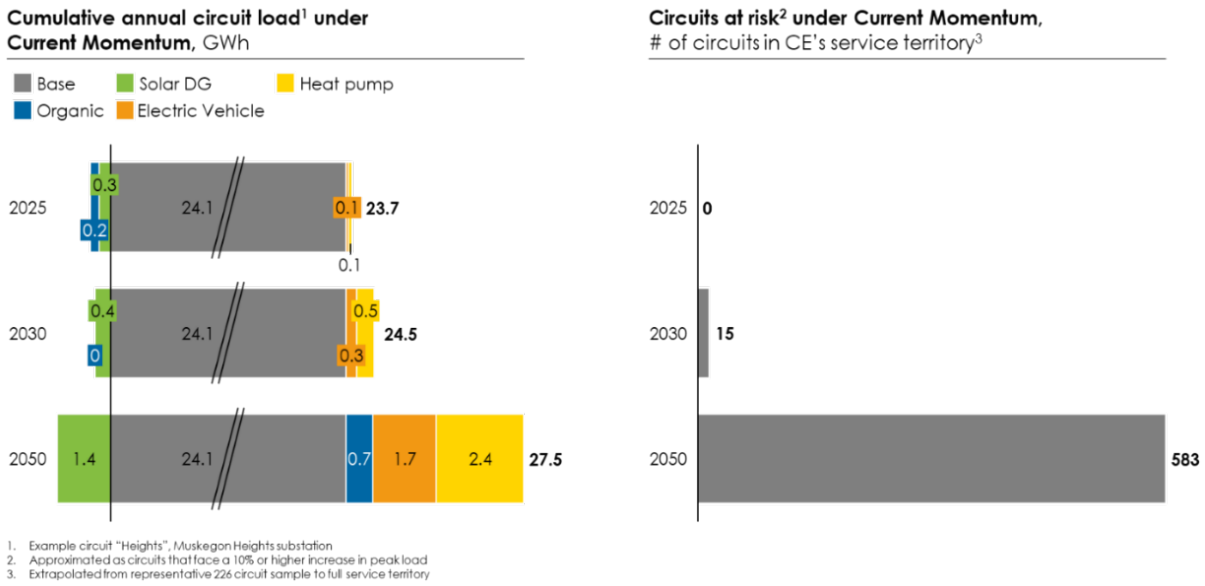
Even by 2030, and under a CM scenario, load-impacting technology adoption could greatly exceed current levels with statewide rooftop solar projected to increase to 1.3 GW, EVs projected to increase to 15% of vehicles, and heat pumps projected to increase to 15% of total households.

Load in the Company's service territory has been largely flat across the years due in part to the relatively limited adoption of electricity intensive heating and mobility technologies, coupled with the success of the Company's Energy Waste Reduction, Demand Response Programs, and summer time-of-use rates.

- Currently, EV adoption in Michigan is 1% of total vehicles and heat pump adoption is 2% of total households while solar DG encompasses 0.4 GW of installed capacity.
- Customer adoption of electrification is projected to lead to ~1-10% of circuits expected to see peak demand increase to at-risk levels by 2030 as shown in Figure 22 below.

This reinforces the Company's plan to first address the reliability impact from climate change, while continuing to develop the capacity of the grid to accommodate future low-carbon technologies.

FIGURE 22
CIRCUITS AT RISK UNDER CONTINUED MOMENTUM

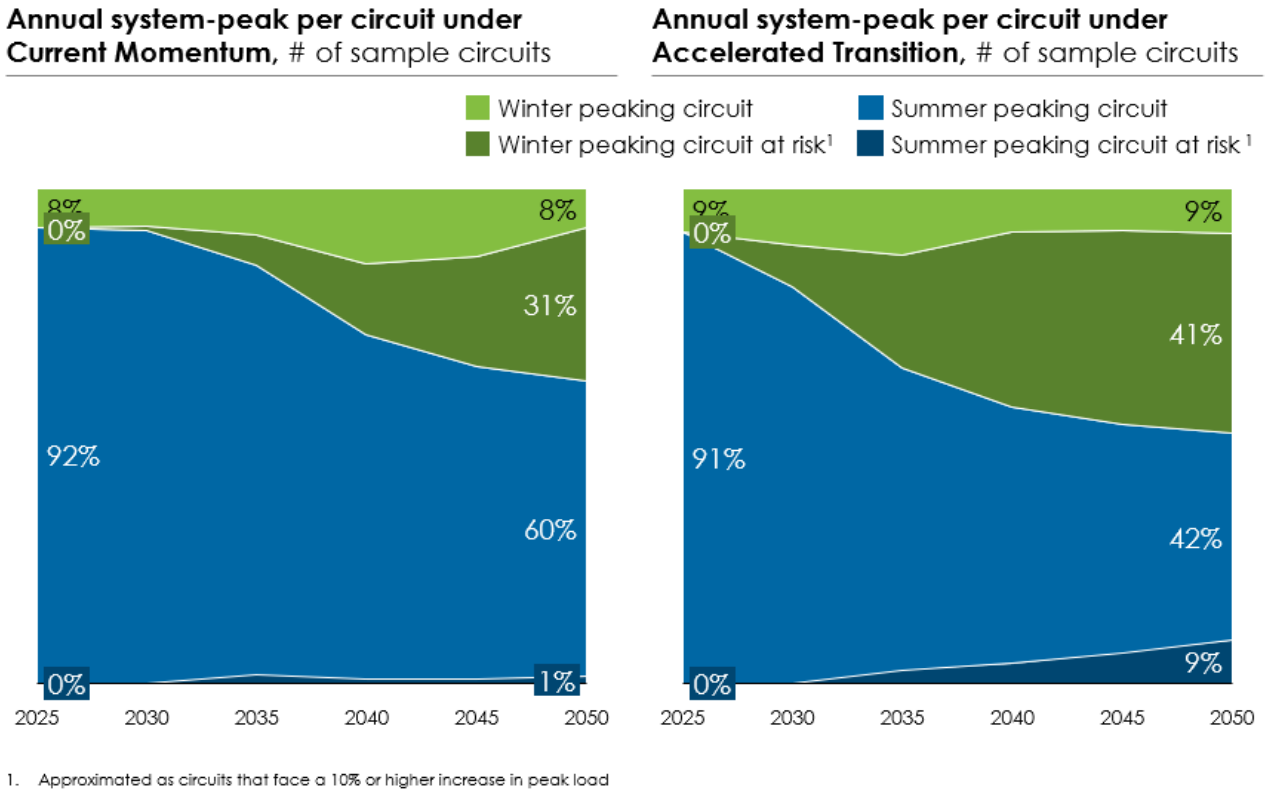


By 2050, peak load is projected to increase to at-risk levels, or greater than 10% increase in peak load, on ~25% of circuits in the CM scenario, driven by customer adoption of EVs and heat pumps.

Depending on the rate of heat pump adoption and the type of heat pumps adopted, hybrid versus fully electric, there is a potential shift from a summer-peaking system to winter peaking system with a ~50/50 summer/winter split by 2050 in the Accelerated Transition scenario as shown below in Figure 23.

FIGURE 23

ANNUAL SYSTEM-PEAK PER CIRCUIT UNDER CONTINUED MOMENTUM



1. Approximated as circuits that face a 10% or higher increase in peak load

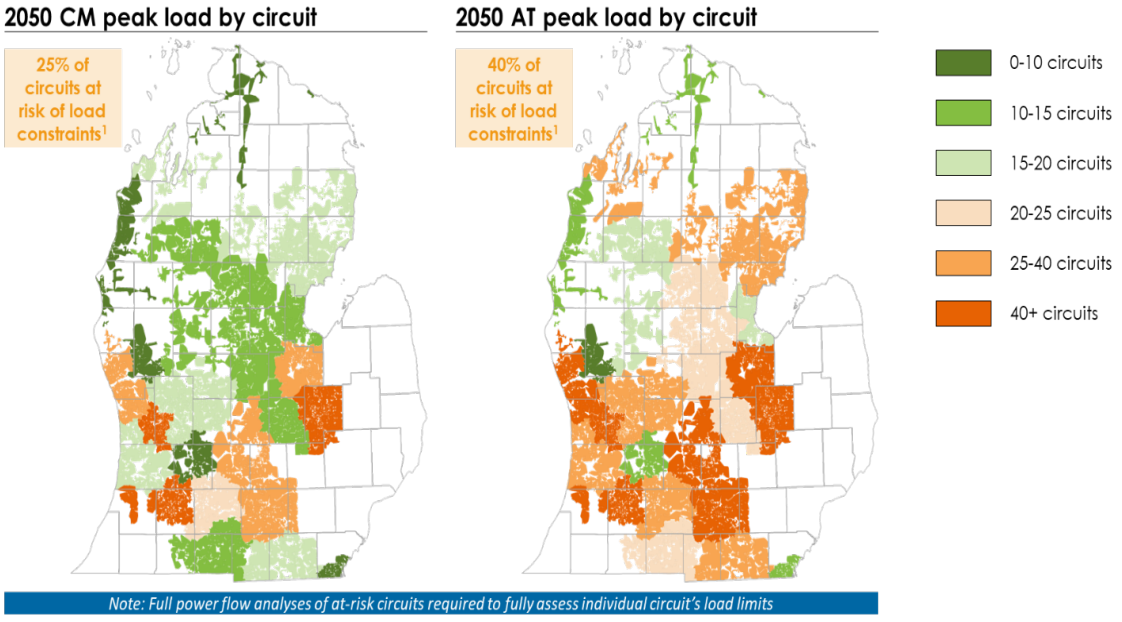
The highest levels of customer technology adoption are likely to materialize in specific circuits. Those at greatest risk of reaching load capacity limits are largely comprised of residential single-family housing customers with high household income, often in suburban areas, given a relatively higher propensity to adopt.

Circuits start reaching at-risk load threshold in 2030, and by 2050 there are 583 circuits out of 2,352 that see >10% peak load increase in a CM scenario.

In an AT scenario, 181 circuits are at-risk in 2030, with up to 40% of examined circuits at risk by 2050 (923 circuits) as shown in Figure 24 below.

FIGURE 24

PEAK LOAD BY CIRCUIT UNDER CONTINUED MOMENTUM AND ACCELERATED TRANSITION



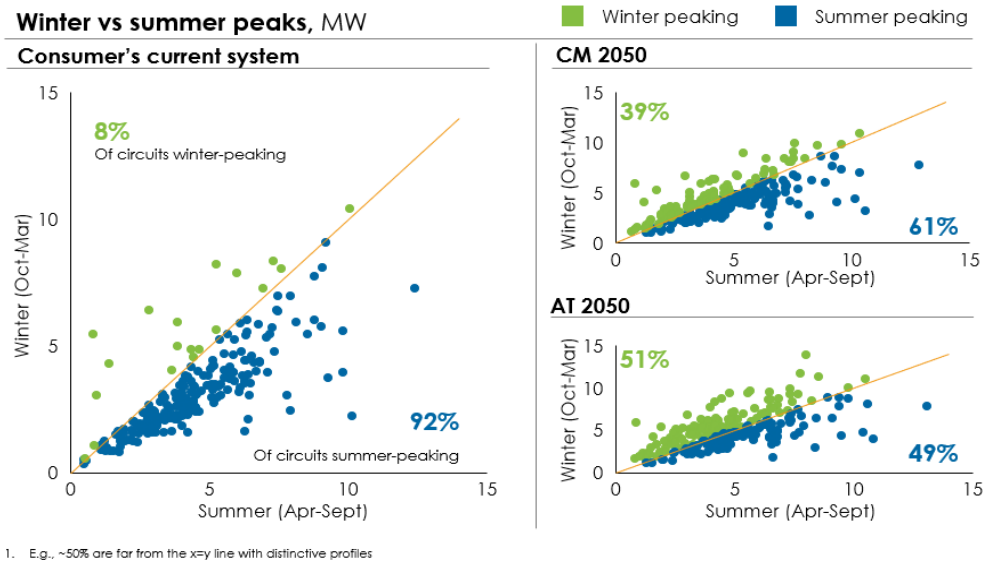
Regarding peak seasonality, summer peak increases remain relatively small—with solar DG offsetting EV load and no heat pump driven load increases.

For now, the Company primarily manages a summer-peaking system. However, the modeling for this scenario suggests this would shift in the future to winter peaking.

As Figure 25 below indicates, summer peaking could shift to winter peaking for 51% of circuits by 2050 in the AT scenario, and for 39% by 2050 in the CM scenario.

FIGURE 25

CIRCUIT PEAK LOADS BY 2050



This shift, driven by projected adoption of heat pumps and their wintertime use, results in a growing number of new winter-peaking circuits, with a substantial fraction reaching the at-risk threshold.

As adoption of electrification technologies continues, the expected circuit-level risk will be heavily impacted by both the timing and character of adoption.

Assumptions around the scale of penetration and time of use for when EVs and heat pumps use the grid have a significant effect on the volume and timeline of forecasted load constraints.

Non-Load Challenges from Customer Technology Adoption

Besides the direct load impacts of customer technology adoption of EVs, solar distributed generation and heat pumps, there is indirect impact on the Company's grid that stems from second-order effects of the uptake of these technologies. They include:

- Bi-directional power flows, especially in circuits that show a propensity to higher-than average adoption of solar DG.
- Power quality issues, stemming from increased decentralized load and generation, could unbalance power factors and degrade voltage quality.
- Interconnections with third parties to facilitate control of distributed customer technology, and to influence load and consumption profiles for the benefit of the grid.

As part of the work going forward, CE must consider such indirect challenges and plan to take action to mitigate them, while simultaneously allowing and supporting the uptake of new load technologies in the service territory.

Such action can often be taken in tandem with actions that help increase resiliency to climate risks or to load increases (e.g., encouraging uptake storage on the LVD system can help mitigate peak load concerns, while at the same time reducing the occurrence of bidirectional power flows).

Federal Energy Regulatory Commission (FERC) Order 2222 mandates that utilities must facilitate the participation of Distributed Energy Resources (DERs) such as rooftop solar in the wholesale electricity market by allowing them to be aggregated and participate alongside traditional, larger scale power sources. Under this FERC Order, utilities must work with DER aggregators to enable them to bid into the wholesale market as a single unit.

The Midwest Independent System Operator (MISO) has proposed a two-phase implementation plan, which FERC has approved. This phased approach creates a DER market in MISO, gradually integrating DERs by 2026 with full implementation of DER Aggregators by 2030.

The Company plans to begin facilitating the participation of DERs beyond demand response (DR) in accordance with MISO's timeline. The Company currently allows for the aggregation and participation of DR, as allowed for by FERC Order 888. Given the lessons already learned from overseeing third-party participation in the wholesale market for DR, the Company expects to need a robust solution for managing, overseeing, and optimizing even more DERs.

A centralized DER Management System ("DERMS") will be critical to supporting system-wide optimization of DERs, especially as the volume of resources increases and the complexity of the relationship with the resources increases with the implementation of FERC 2222.

The Company defines DERMS as *an enterprise scale software platform that is located at the utility's operational center*.

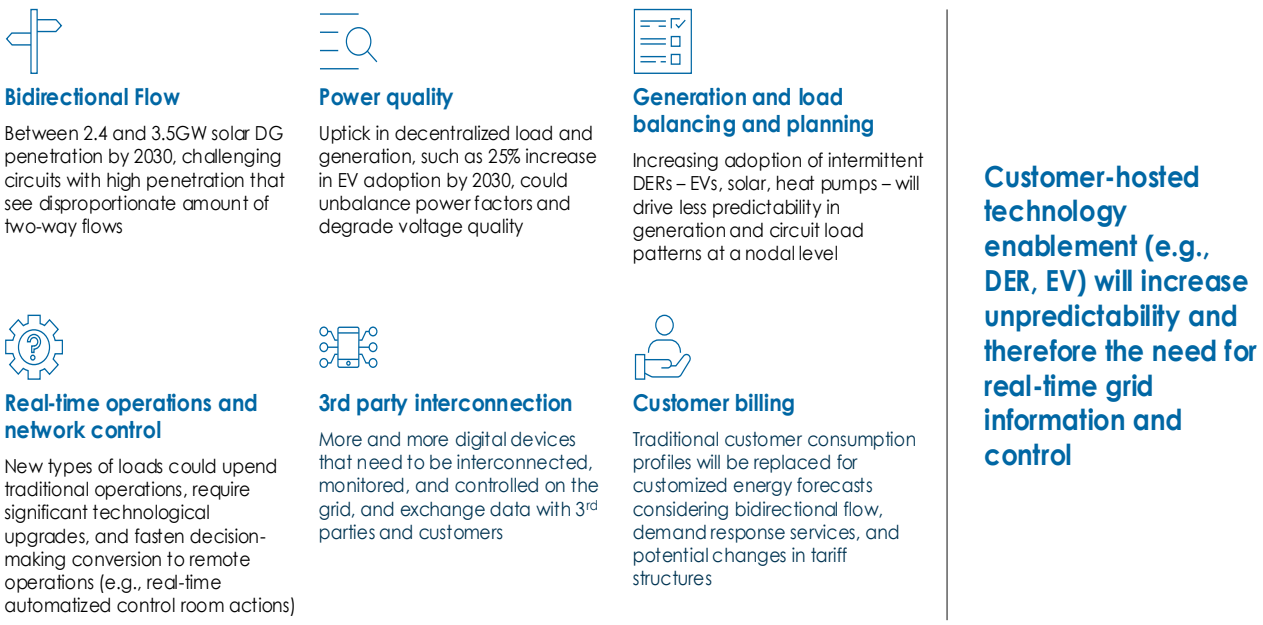
- A DERMS monitors, controls, and optimizes DERs in a manner that maintains or improves the reliability, efficiency, and overall performance of the electric distribution system.
- This structure allows DER performance to be optimized for reliability and efficiency while simultaneously accounting for local, regional, and system-wide constraints and requirements.

Optimization at a system-wide level will be driven by bulk power constraints and requirements (e.g., frequency, capacity requirements, SAIDI, etc.).

A DERMS provides the functionality required to manage these wide-ranging factors to realize system-wide optimization. This includes coordination with other enterprise systems such as an Advanced Distribution Management System ("ADMS") detailed later in this report, and the Demand Response Management System ("DRMS").

FIGURE 26

NON-LOAD CHALLENGES FROM CUSTOMER TECHNOLOGY ADOPTION



Defining The Reliability Roadmap

In the face of the challenges outlined above, the Company developed the *Reliability Roadmap* to ramp up its investment in developing a modern grid capable of mitigating the immediate threats from extreme weather.

- The *Reliability Roadmap* represents an increase in the scale of infrastructure investment, spending on Forestry Line Clearing, and increased equipment inspection relative to levels set in rate cases prior to Case No. U-21585.
- It also adds additional resiliency investment, such as overhead to underground conversions, and the fractionalization of circuits and substations.

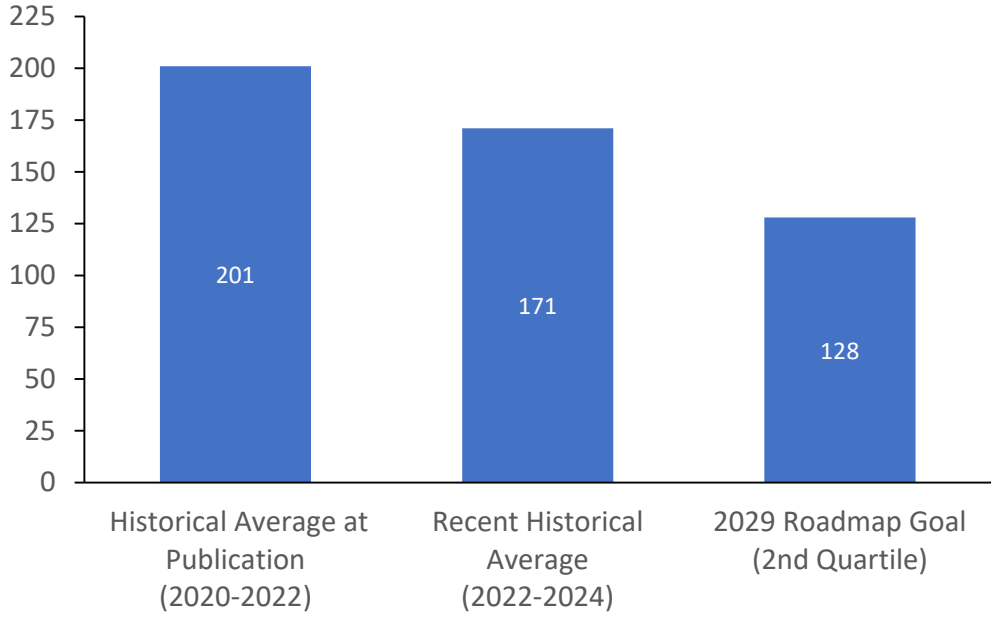
Investment at this scale will also set the Company on a path to build a grid that will ultimately deliver on the following three objectives mentioned earlier in this document:

1. **Delivering reliability performance into the 2nd quartile of nationwide utilities.**
2. **Delivering a grid where no single outage event will affect more than 100,000 customers.**
3. **Delivering a grid where no customer will be without power for more than 24 hours following an outage event.**

Additionally, investment at the scale outlined in the *Reliability Roadmap*, if approved by the Commission, will deliver significantly improved SAIDI performance by the end of the decade, as shown in Figure 27 below. These investments will provide a substantial improvement over the Company's average 2020 to 2022 performance of 201 minutes, delivering 2nd quartile performance by 2029.

FIGURE 27

SAIDI EXCLUDING MEDS PROJECTIONS –RELIABILITY ROADMAP GOAL



The *Reliability Roadmap* differs in scope and scale from the 2021 EDIIP, which was developed prior to the Company's advanced climate and technology adoption modeling explained earlier in the Scenarios and Future Impacts to the Distribution System section of this report.

The Company anticipates the pace of reliability investment will level off after investments made to address rapidly changing climate and customer technology adoptions have been implemented.

Looking beyond 2030, the mix of investments will likely shift to ensure the system has capacity to service load from increased extreme heat days, and electrification of transit and home appliances.

The Company's SAIDI goal is achieved through numerous investments and work activities that all contribute to the overall reliability goal. These approaches can be considered in four categories: *Hardening*, *Inspections*, *Forestry Line Clearing*, and *Digital Automation*.

Hardening consists of capital investments to repair and replace HVD and LVD assets such as lines and substations.

- These investments address infrastructure on the system at risk from severe weather and allow for proactive resiliency plans, such as undergrounding or fractionalization.
- Further details on the investment categories including the 5-year investment plan and approaches to reliable operations are included in the *Asset Management* sections of this report under LVD Lines, HVD Lines, and Substations.

Inspections include ground and aerial inspections on both the LVD and HVD systems, and work related to addressing any identified failures.

- Company inspections of distribution lines and substations are used to locate and repair failed equipment, to identify specific areas to target investments based on probability of future issues, and to prioritize projects that will deliver the greatest reliability improvements for customers.
- Further detail on the investment categories including the 5-year investment plan and Company inspection cadence is included in the Overview of Asset Management section of this report under *LVD Lines*, *HVD Lines*, and *Substations*.

Forestry Line Clearing includes the work responsible for maintaining clearance between vegetation and energized Company equipment, and to eliminate the vegetation hindering accessibility to the Company's electric lines.

- This vital work is the most impactful towards improving system reliability and encompasses both HVD and LVD specific programs.
- Further detail on the Company's approach to Forestry Line Clearing including the 5-year clearing plan, best practices, and risks it responds to are discussed in the Forestry Line Clearing Program section of this document.

Digital Automation includes technology-driven solutions to increase efficiency of the Company's distribution planning work, service restoration, and line clearing operations.

- An example of this work is the Company's use of drones and Imagery Analytics to re-imagine the Company's inspection processes by providing a 360-degree view of its distribution assets in the field. This application shows **the potential to enhance employee and customer safety, reduce the cost of work, and to improve reliability and resiliency** through more targeted work.
- These investments are a key component of the Company's glidepath to achieving breakthrough SAIDI and reliability performance.
- Further detail on the Company's digital and automation can be found in the section of this plan under Grid Automation and Next Digital Investments.

FIGURE 28

IMAGERY FROM DRONE INSPECTION COMPARED TO VISUAL GROUND INSPECTION





Planning Process

Annual Planning

Distribution planning is an iterative process in which planning engineers and operators identify projects and maintenance work needed to address system performance issues and meet the Company's goals and objectives for the electric distribution grid.

All work is planned in consideration of expected customer demand and emergent replacements, planned maintenance, and improvements to the grid.

As engineers and operators identify work, this informs planned infrastructure investments, inspections and maintenance of existing assets, projected customer-requested and emergent work, and supporting staff.

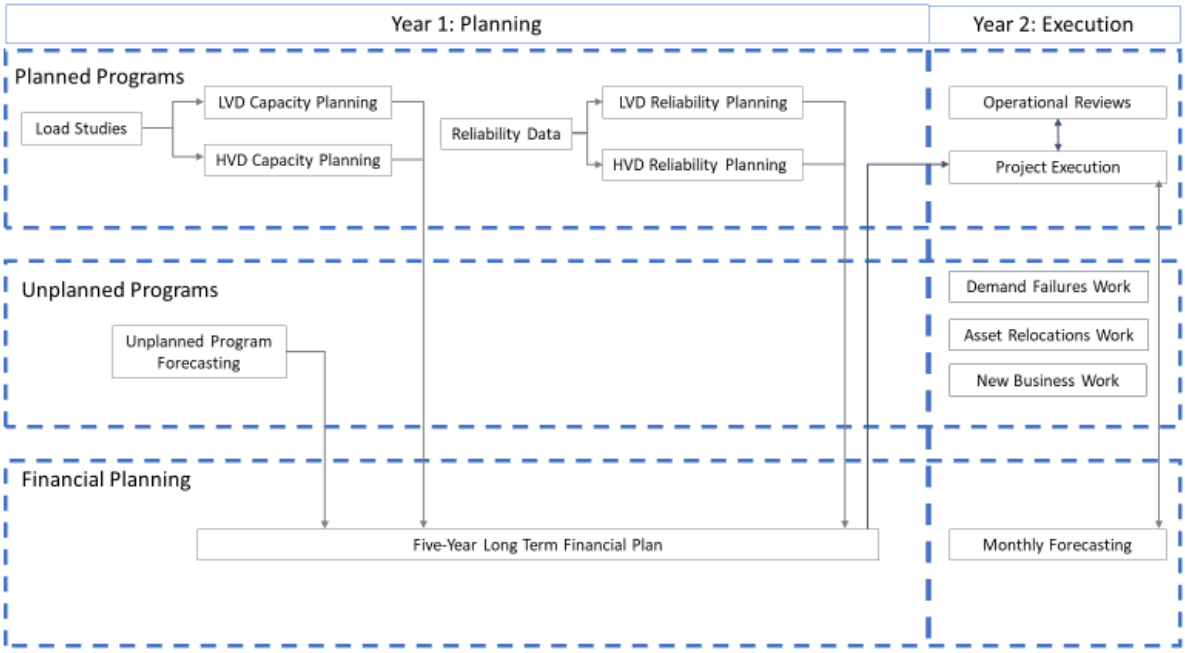
Repeating this process every year results in a rolling 5-year planning process in which one incremental year is added every cycle.

Depending on the nature of a given program, these identified investment needs are based on a combination of pre-planned or known projects, and anticipated volumes of emergent work, generally based on historical volumes of work accounting for observed trends.

Figure 29 shows how these planning activities connect with each other.

FIGURE 29

ELECTRIC DISTRIBUTION FINANCIAL AND ENGINEERING PLANNING PROCESS



To align with industry best practices, the Company has consulted the Electric Power Research Institute's ("EPRI") *Distribution Grid Resiliency: Prioritization of Options* report (EPRI, Palo Alto, CA: 2015. 3002006668) published in 2015 and made publicly available at the EPRI website.

EPRI published this report on the prioritization of options for grid resiliency incorporating research that EPRI conducted on overhead structures, vegetation management, undergrounding, grid technology, and storm response practices.

The report provides a benchmarking analysis of the costs and benefits of various options for improving reliability and resiliency, such as Undergrounding and Fractionalization, that the Company will apply to its distribution planning, as well as discussion on how to rank the reliability of circuits so that projects can be prioritized.

Engineering Planning Process Overview

The Company's electric distribution engineering planning process runs throughout the year.

The Company conducts engineering work in all programs to address specific objectives and issues on the distribution system, depending on the type of work, the affected customer profile, and the attributes of the assets in question (e.g., HVD, LVD, substations).

The Company makes capital investments under two broad classifications, known as *unplanned* and *planned*.

***Unplanned* capital investments** correspond to customer requests or emergent system needs, such as for new business connections, restoration of service after storms, or requests for asset relocations. In the Company's electric rate cases, these capital investments fall in the New Business, Demand Failures, and Asset Relocations investment programs.

These investments are not strictly 'unplanned' as the Company does anticipate having to make these investments but is usually unable to plan specific projects until an interruption or defect occurs, the Company receives a request from a customer or another project-triggering event occurs, such as a broken crossarm.

The defects identified from inspection and maintenance programs, described further in the Overview of Asset Management section, are unknown prior to identification but are prioritized for mitigation based on safety and reliability risk.

Instead, using a variety of external economic and industry indicators the Company can (to some extent) forecast related volumes of work, funding required, and detailed analyses of the state of the system in advance. For example, the Company uses data from the *Home Builders Association of Michigan* to estimate new housing starts to help forecast future spending on new service connections.

***Planned* capital investments** proactively improve reliability, address capacity constraints, and invest in new tools and technology. In the Company's electric rate cases, these capital investments fall in the Reliability, Capacity, and "Electric Other" investment programs.

For these investments, the Company prioritizes investments to maximize customer benefit in the most cost-effective manner. Specific investment prioritization varies based on the type of asset, but broadly speaking the Company uses several critical inputs and analyses to aggregate multiple data sources to best target and prioritize customer reliability, identifying specific investments based on the probability of future issues.

Different components of distribution planning—for example, planning for LVD lines or HVD substations—are overseen by respective program managers, who are responsible for developing plans in those areas.

Under these program managers, engineering planning leads and individual engineering planners have responsibilities for developing specific projects. Investment planning for the *planned* investments broadly follows three stages:

1. **Reviewing system needs** – Engineering planners review system needs to identify critical target areas at an LVD circuit, LVD zone, LVD or HVD substation or HVD line level, using a variety of asset-specific technical inputs and analytical tools, including real-time data and inspection results.
2. **Determining required actions and developing projects** – Once a customer or system need is identified, engineering planners determine required actions and develop concepts that compare alternatives and identify a recommended project based on the most economical and effective solution, such as to repair the damaged asset or replace it.
3. **Prioritizing and sequencing work** – Program managers and engineering planners prioritize, and sequence projects based on project timelines, customer benefits, system-wide workload balancing, and customer base balancing.

In certain investment areas, particularly for the LVD system, the Company uses an additional initial step in its process for grouping circuits and identifying projects, known as *Grid Archetypes*. Many larger individual projects are evaluated using a *Concept Approval* process. Both topics are discussed later in this Planning Process section.

In 2024, the Company also began using Copperleaf to further improve its planning process and its project optimization. Full implementation of Copperleaf will take time, but the Company expects to more fully integrate it into its planning processes throughout 2025. Copperleaf is described in more detail below.

Concept Approval Process

To ensure its electric distribution investments are reasonable and prudent, the Company considers many of its planned electric distribution investments against alternatives and develops concept approval documentation to demonstrate why the selected project is the optimal investment to make.

Through this internal concept approval process, the Company ensures the problem is clearly defined, alternatives are evaluated based on cost and solution to the problem, and there is a strong business case for the recommended project.

The general structure of a concept approval includes the following:

- Background and identification of problem
- Evaluation of alternatives
- Determination of costs and benefits of alternatives
- Selection of best alternative
- Approvals and revisions, where necessary

Based on the Company's identified goals, program managers provide direction to the Company's engineering planners regarding the types of work to be targeted.

Engineering planners gather data and perform problem solving to identify alternatives and eventual selection of a project. Once the engineering planners have identified alternatives, selected a project, and drafted a concept approval, they are reviewed by successively higher levels of management based on the projected cost for the selected project.

For small projects, no approval may be needed beyond that of the engineering planning director. In most cases, projects approved by the engineering planning lead go on to the program manager for review and approval, and may go higher for further review, depending on the projected cost of the project.

At each level of review, the reviewing party may request further revisions.

Once a concept has received all necessary approvals, it is considered an approved part of the Company's investment plan. It is released to the Company's electric design engineers for detailed design work, which consists of the following:

- During the design phase, costs may vary slightly from the original concept approval cost projections.
- If costs vary significantly based on design work, the variance may be reviewed by the program manager and engineering planner and, if necessary, resubmitted for approval with revised costs.

- If there are no significant financial variances between concept approval and the finished design, then the project proceeds to construction.

At this point, the Company's Planning and Scheduling group identifies and assigns either Company or contractor workforce resources to the project (depending on project specifics) and the project is scheduled for execution.

During construction, the program manager regularly reviews actual costs incurred against the budget. Unexpected cost variances during construction are managed through the Company's ongoing monthly budgeting process, with adjustments to the overall workplan made as necessary to manage to budget.

Asset Investment Planning Optimization

Copperleaf is an Asset Investment Planning ("AIP") decision analytics software solution, designed to support critical infrastructure investment planning for industries including electric utilities. Copperleaf combines financial and non-financial metrics to provide a comprehensive framework for evaluating, prioritizing, and optimizing investments, enabling organizations to make more strategic and data-driven decisions about their asset portfolios.

Copperleaf operates using a "Value Framework," a customizable set of models that quantify the benefits associated with various types of investments.

Copperleaf evaluates projects against specific "value measures" within these frameworks, encompassing multiple categories of benefits, such as risk mitigation, reliability improvements, cost savings, regulatory compliance, and customer satisfaction. By assigning a measurable value to each of these factors, Copperleaf enables organizations to compare projects objectively, weighing both their immediate financial returns and broader, long-term benefits.

- Copperleaf is particularly valuable because it can assess projects through both financial and risk-based valuations. Copperleaf employs risk-adjusted project prioritization, using a structured approach to identify high-risk assets and projects that, if left unaddressed, could lead to significant future costs or reliability issues.
- This risk-based approach includes metrics like Probability of Failure and Consequence of Failure, which provide a quantified understanding of the impact of each asset or project on the system's overall stability and resilience.
- Copperleaf's optimization capabilities will allow the Company to build a project portfolio that better supports its distribution objectives. By integrating projects into a unified system, the software can run different investment scenarios to determine the optimal plan that balances financial constraints with maximum system-wide benefits.

For Consumers Energy, implementing Copperleaf means distribution projects can be systematically analyzed and optimized. Systematic project optimization will enable the organization to proactively address aging infrastructure, improve system reliability, and meet regulatory requirements, all while enhancing customer satisfaction through reduced outages and optimized grid performance.

Grid Archetypes

Since 2018, the Company has developed and used an approach referred to as *Grid Archetypes* to consider additional LVD circuit characteristics beyond traditional reliability metrics of SAIDI, SAIFI, and CAIDI, when assessing grid performance.

This approach ensures no section of the grid is inadvertently left behind—that **both rural and urban customers, and residential, commercial, and industrial customers all benefit equitably** from the Company's investments, by making sure that investments are optimally made across the Company's distribution system.

In the Archetypes approach, the Company groups each of its LVD circuits into one of seven archetype categories based on various circuit characteristics. Circuit characteristics include geographic characteristics (i.e., circuit line-miles, distance to Company service centers), customer mix, circuit load and voltages, and reliability metrics. Full details on all circuit characteristics and their use can be found in Appendix A.

Figure 30 below defines each Archetype and illustrates where each of the Archetypes are located throughout the Lower Peninsula.

FIGURE 30

GRID ARCHETYPES



Once the LVD circuits are grouped, Company leadership establishes multi-year goals and broad budget guidance. This guidance provides multi-year guidance on guardrails for how much investment should be allocated to each archetype.

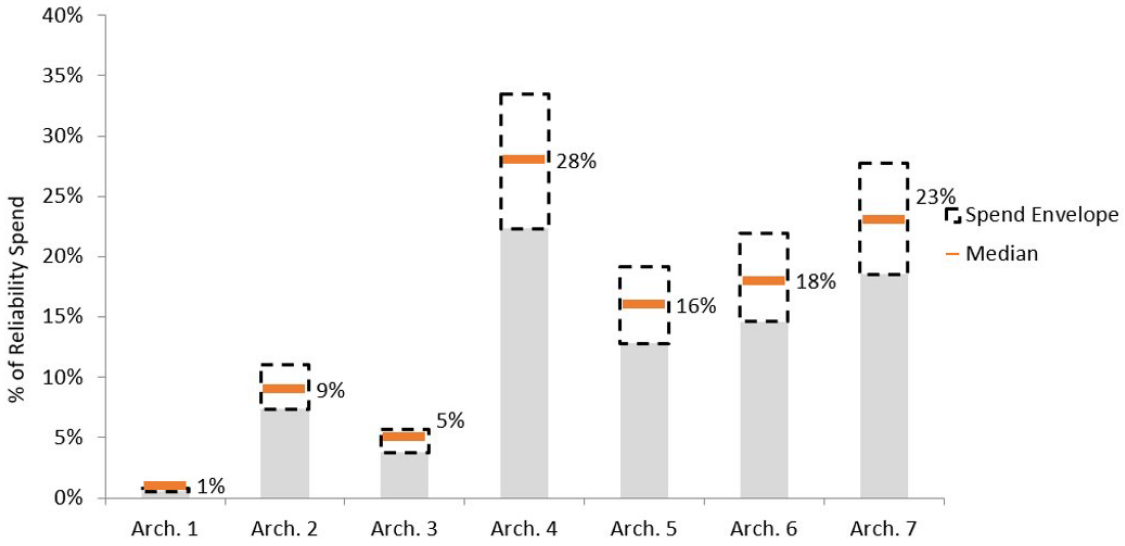
During this process, the Company takes its planned, systemwide LVD capital spending for a given year and allocates the spending to each archetype based on different archetype characteristics or archetype performance measures.

The Company then takes the median allocation of all allocations and calculates spending guardrails for each archetype based on a certain amount of allowable variance. An illustrative example of these calculations is shown in Appendix A.

The result of this process is an illustration of targeted spending ranges for each archetype, as shown in Figure 31 below.

FIGURE 31

ARCHETYPE TARGETED SPENDING RANGES – ILLUSTRATIVE EXAMPLE



	Arch. 1	Arch. 2	Arch. 3	Arch. 4	Arch. 5	Arch. 6	Arch. 7
% of Line Miles	1%	6%	4%	18%	25%	17%	29%
% of Customers	1%	8%	9%	41%	14%	9%	18%

If the Company's planned spending in each archetype falls outside the "spend envelope" guardrails, then spending can either be reallocated to better ensure optimal prioritization of investment across the LVD system or the Company can develop a justification for why spending outside of the guardrails is necessary.

Equity and Environmental Justice in the Planning Process

Analyzing Equity of Distribution Performance

Since the Company filed its second five-year EDIIP in June 2021, the MPSC and other parties have indicated increasing levels of interest in EJ, energy equity, and other similar topics.

For purposes of distribution planning, these issues primarily concern how different communities experience reliability and resiliency, as well as future implications for grid access when it comes to customer adoption of EVs and other electric technologies and customer adoption of distributed energy resources.

Reliability and resiliency concerns are pronounced because people living in disadvantaged communities may have more difficulty replacing spoiled food and medicine following power interruptions, and may have fewer resources to secure back-up power or find alternative accommodations during extended power outages.

In its September 8, 2022, Order in Case No. U-20147 ("September 8 Order"), the Commission provided expectations around EJ and energy equity data to be shared in this EDIIP, directing utilities to provide information on the distribution system, particularly maps providing system information overlaid with socioeconomic context.

Additionally, in the settlement agreement for the Company's Electric Rate Case, approved by the Commission in Case No. U-21224 ("Settlement Agreement"), the Company agreed to further provisions around data that would be shared, as well as ways the Company would work to incorporate EJ considerations into distribution planning.

These concerns were substantially addressed in the 2023 version of this Reliability Roadmap, as well as in the Company's 2023 and 2024 electric rate cases (Case Nos. U-21389 and U-21585). Those analyses built on one another, and indicated that:

- On a systemwide basis, the Company's EJ communities have comparatively good reliability; but
- There are particular EJ communities that do face reliability challenges

The Michigan Department of Environment, Great Lakes, and Energy ("EGLE") has developed the MiEJScreen tool to assess the vulnerability of census tracts based on various inputs, creating a score from 0-100, with 100 indicating the most vulnerable communities. The Company has defined any census tract with a MiEJScreen score of greater than 80 as an "EJ census tract."

Electrical geography does not always match political geography, and the Company uses the term "EJ circuit" to refer to any LVD circuit that serves an EJ census tract in whole or in part. Because of this, some EJ circuits include individual customers who do not reside in EJ census tracts. When the context is more general, the Company sometimes uses the term "EJ communities" to describe the general concept of vulnerable customers in a certain defined area.

The Company has 249 total circuits overlapping in whole or in part with EJ census tracts, as defined in the Settlement Agreement; of these, 24 are customer-owned or single-customer-dedicated circuits, leaving 225 general distribution circuits serving EJ customers according to this definition.

The Company's data has consistently shown that EJ census tracts, when considered together, consistently have better reliability performance than other census tracts in the Company's service territory.

In the summer of 2024, the Company performed two different analyses to probe further into reliability concerns for EJ communities. These two analyses both address the same general concern, but they are independent of each other and there is no meaningful way to cross-reference them against each other; each one stands alone in its analysis.

First, the Company analyzed how many individual EJ circuits have poor reliability that is being obscured by good reliability on other EJ circuits that averages out in a systemwide analysis. To do this, the Company compiled all 190 EJ circuits on its system and reviewed their individual SAIDI, both including and excluding MEDs, over the past five years.

The Company then compared each EJ circuit's SAIDI scores against the Institute of Electrical and Electronics Engineers ("IEEE") quartiles. The Company found that, over the period from 2019 through 2023, 118 of the 190 EJ circuits had average SAIDI excluding MEDs that were in the first or second IEEE quartile, indicating better than average SAIDI. A full 80 EJ circuits had first-quartile SAIDI excluding MEDs. These first and second-quartile circuits serve about 97,000 customers.

On the other hand, 72 EJ circuits had average SAIDI excluding MEDs in the third or fourth IEEE quartile; these circuits serve approximately 78,000 customers.

The Company found somewhat similar results for SAIDI including MEDs, but with proportionally fewer circuits and customers in the first quartile and more circuits and customers in the fourth quartile.

FIGURE 32

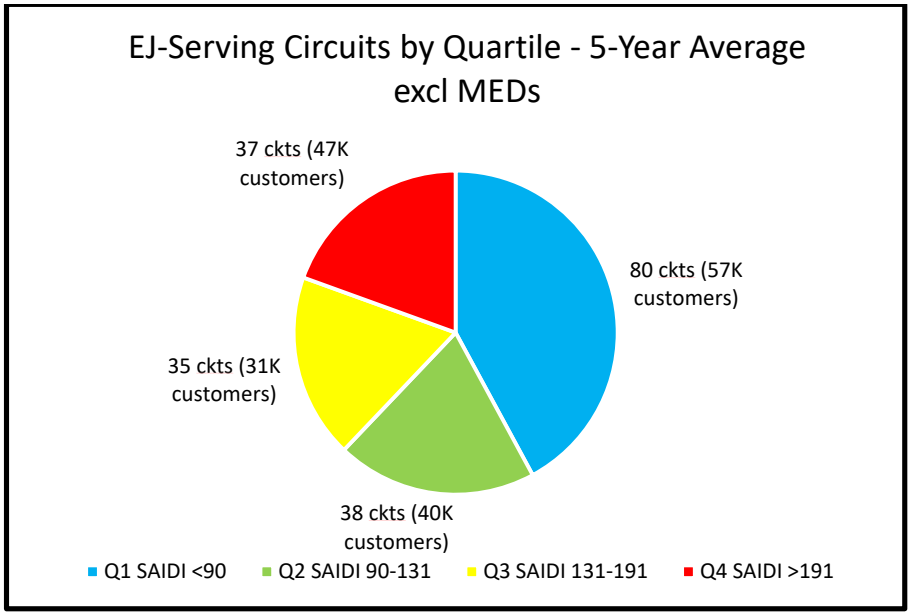
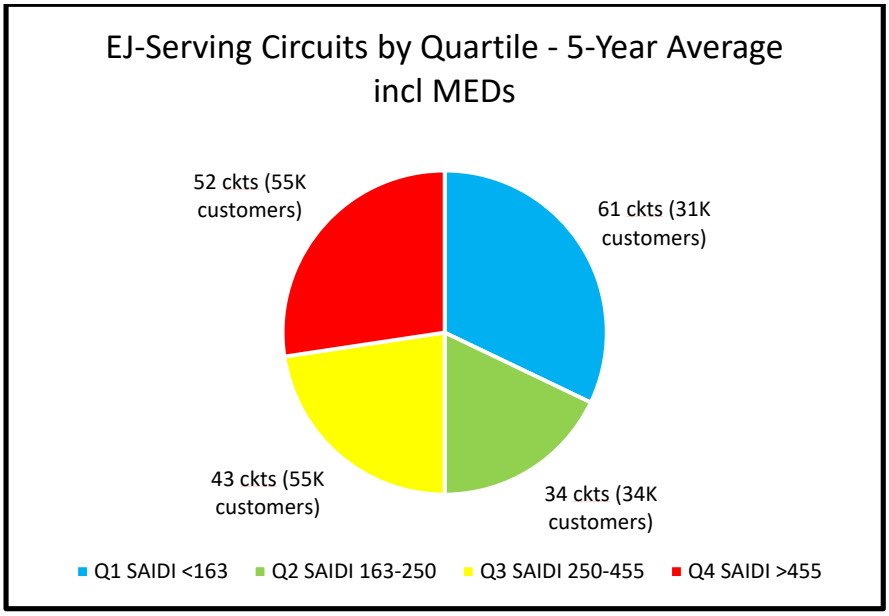


FIGURE 33



This analysis clearly indicates that some EJ communities face challenging reliability issues, which are only magnified by the vulnerabilities that these communities face when dealing with interruptions.

Second, the Company conducted another analysis over the summer of 2024 to more closely study how EJ census tracts perform relative to similar non-EJ urban census tracts. The Company has 56 EJ census tracts in its service territory, and all of them are defined as urban by the U.S. Census Bureau.

For this analysis, the Company compared the 56 EJ census tracts to similarly situated urban non-EJ census tracts. For *each* of the 56 EJ census tracts, the Company identified the five non-EJ urban census tracts that were most like the respective EJ census tract in terms of population size and housing density. Therefore, each of the 56 EJ census tracts was matched up with five corresponding non-EJ urban census tracts, meaning the Company could make 280 total comparisons of EJ census tract vs. non-EJ urban census tract performance (56 x 5).

The Company then made these 280 census tract performance comparisons for 12 different reliability metrics:

- SAIDI including MEDs
- SAIDI excluding MEDs
- SAIFI including MEDs
- SAIDI excluding MEDs
- Customer Average Interruption Duration Index (“CAIDI”) including MEDs
- CAIDI excluding MEDs
- Customers Experiencing Multiple Interruptions (“CEMI”)-4
- Customers Experiencing Lengthy Interruption Duration (“CELID”)-5
- All-weather 36-hour restoration percentage
- Catastrophic 48-hour restoration percentage
- Normal condition 8-hour restoration percentage
- Gray-sky 24-hour restoration percentage

The Company performed the 280 census tract performance comparisons for these 12 metrics for each of the five years from 2019 through 2023, yielding a total of 16,800 individual data points (280 x 12 x 5).

For each individual data point of comparison, the Company determined whether the EJ census tract or the non-EJ urban census tract with which it was being compared performed worse. To illustrate this, consider an EJ census tract *Y*.

- Census tract *Y* would have been paired with five non-EJ urban census tracts: *A, B, C, D,* and *E*. For SAIDI including MEDs in 2023, the Company would compare *Y*’s results with those of *A, B, C, D,* and *E* separately.
- The Company would count each time *Y* had the higher SAIDI, and each time one of the other census tracts had a higher SAIDI. For *Y*, this would then be done for each metric and each year.

The Company did this for all 56 EJ circuits, and totaled up how often the EJ census tract performed worse, and how often the non-EJ census tract performed worse.

FIGURE 34

Reliability Metric		Which Performs Worse on Average?	How Often is EJ Worse?
SAIDI	excl MEDs	EJ	51.29%
	incl MEDs	EJ	54.75%
SAIFI	excl MEDs	EJ	57.84%
	incl MEDs	EJ	58.27%
CAIDI	excl MEDs	Non-EJ	42.88%
	incl MEDs	Non-EJ	45.47%
CEMI-4		EJ	64.82%
CELID-5		EJ	50.22%
Restoration Time	All-Weather 36-hr	EJ	69.92%
	Catastrophic 48-hr	Non-EJ	41.58%
	Normal 8-hr	EJ	57.27%
	Gray-sky 24-hr	EJ	59.06%

These results indicate that if you take the Company's EJ census tracts and compare them, on a granular basis, with the most comparable non-EJ urban census tracts, the EJ census tracts often perform worse on key reliability metrics. The percentages indicate that the EJ census tracts perform worse on a moderately more often basis.

Vulnerable Communities Resiliency Plan

The Company does not believe it is "good enough" to point to systemwide averages, as good as they may be, and let it go at that, leaving some vulnerable customers behind.

To address the issue of customers in EJ communities facing poor reliability, the Company has developed its *Vulnerable Communities Resiliency Plan*. The purpose of this Plan is to make targeted strategic investments on EJ circuits so that every EJ circuit has SAIDI including MEDs that is in the second IEEE quartile or better.

In other words, the *Vulnerable Communities Resiliency Plan* will eliminate EJ circuits experiencing worse than the industry average, and it will do so including MEDs to account for the actual experiences of those customers.

The total proposed investments are as follows, to take place over 10 years:

- Fractionalization: $200 million of total investment
  - Six new substations – one for each EJ circuit with over 3,000 customers
  - 133 new circuit exits – one for each EJ circuit with over 1,000 customers
- LVD line rebuilds: $350 million of total investment
  - Rebuild 665 miles of primary LVD circuit to create a high-reliability mainline three-phase (i.e., aerial spacer cable or underground, based on local conditions)
- Other work: $50 million of total investment
  - 400 new reclosers to ensure no protective zones exceed 2 miles in length
  - 335 new switches (i.e. one every mile)
  - Approximately 3,000 additional fuses

While the new substations were already included in the Reliability Roadmap in 2023, the remainder of the investments are incremental. It is crucial to emphasize that t**he Company is not proposing to take reliability investments that are already in the Reliability Roadmap and redirect those to focus on the *Vulnerable Communities Resiliency Plan***, which would disadvantage customers in other parts of the Company's service territory.

The Company will maintain its planned reliability investments and then perform these targeted EJ investments in addition to those.

Note that in the Settlement Agreement as part of Case No. U-21224, the Company committed to "propose a plan to incorporate environmental justice and equity into the Grid…Archetypes analysis which the Company uses to prioritize its distribution investments in rate cases." The Company did so in the summer of 2023, and added a new reliability 'flag' to the Grid Archetypes process.

By adding EJ status to the list of reliability flags, an EJ circuit that previously only triggered one reliability flag (and therefore was not prioritized) would instead be prioritized.

However, the Company believes the new *Vulnerable Communities Resiliency Plan* effectively supersedes this EJ flag methodology. The purpose of the EJ flag was to modestly weight investment decisions in favor of EJ communities. The *Vulnerable Communities Resiliency Plan* will instead **directly steer critical investments to those communities** in a dedicated program.

Other Efforts in EJ Communities

In addition to the *Vulnerable Communities Resiliency Plan*, the Company is also proposing targeted replacement of open-wire secondary, which heavily impacts EJ communities in the Company's service territory. Furthermore, the Company is proposing to convert non-standard voltages to standard voltages.

These conversions of non-standard voltages will:

a. Eliminate ungrounded conductors, which can pose safety hazards.

b. More easily facilitate load transfers to reduce outage times.

c. Improve the capacity of the circuit to accommodate increased load in some cases.

The Company's plans for open-wire secondary and non-standard voltages are discussed in more detail later in the LVD Safety-Focused Issues and Investments section of this report.

Further Analysis

The Commission's final Order in Case No. U-21389 directed the Company to develop a regression analysis to statistically study the interaction between EJ issues and distribution reliability, in addition to the analyses discussed above.

The Company has developed that analysis, and it is being filed as an exhibit in Case No. U-21870, concurrent with this update to the Reliability Roadmap. Based on the Commission's final Order in Case No. U-21585, the Company anticipates it will update this regression analysis periodically going forward as well.

As the Company executes these plans for EJ communities, it recognizes the need to hear direct input from representatives of impacted customers in those communities, and the Company will explore avenues to get that input through appropriate channels.

- The Company has been an active collaborator in the MPSC Staff's Energy Affordability and Accessibility Collaborative; this ongoing workgroup provides a cross-functional way for utilities and other organizations to discuss challenges in energy equity, and the MPSC's process includes representation for low-income customers and other opportunities for those customers to be heard.
- The Company's Community Affairs team regularly reaches out through a variety of communication channels to local governments, community organizations, and individual customers regarding plans for major projects, including those designed to improve reliability in an area.
- The Company is willing to explore an annual meeting during which affected customers and their representatives can get information and provide input on the Company's efforts in EJ communities.

The 2023 version of the Reliability Roadmap included maps overlaying reliability data for EJ circuits and EJ census tracts. The Commission's Order in Case No. U-21389 directed the Company to work with Staff to develop a means for interested parties to access Geographic Information System ("GIS") data from the Company, and the Company undertook this effort during late 2024 and early 2025.

As one outcome of this, the Company has now posted interactive GIS maps to its public website that overlay EJ circuits and EJ census tracts with the ability to view SAIDI and SAIFI data both with and without MEDs. This is available at:
https://experience.arcgis.com/experience/1d84e089ff5e4a2382df340d15689488

Hosting Capacity in EJ Communities

The Settlement Agreement in Case No. U-21224 also included a commitment by the Company to include data on hosting capacity in EJ communities in future filings. To date, the Company's hosting capacity analysis has largely been limited to an initial "go/no-go" analysis that was discussed in the 2021 EDIIP and published in detail on the Company's website in the fall of 2021.

Information based on that analysis relating to EJ communities was provided in the Company's 2023 electric rate case in Case No. U-21389. As discussed later in this updated version of the Reliability Roadmap, the Company is working in 2025 on further developing its hosting capacity analysis capabilities, which will deliver the ability to better study hosting capacity for EJ communities as well.

Overview of Asset Management

The *Reliability Roadmap* reflects the Company's strategy to meet the safety, equity, reliability, and resiliency needs of customers through the grid both now and into the future. This plan focuses on assets to modernize the Company's electric distribution system to safely provide power with fewer, shorter, and less frequent power outages for customers.

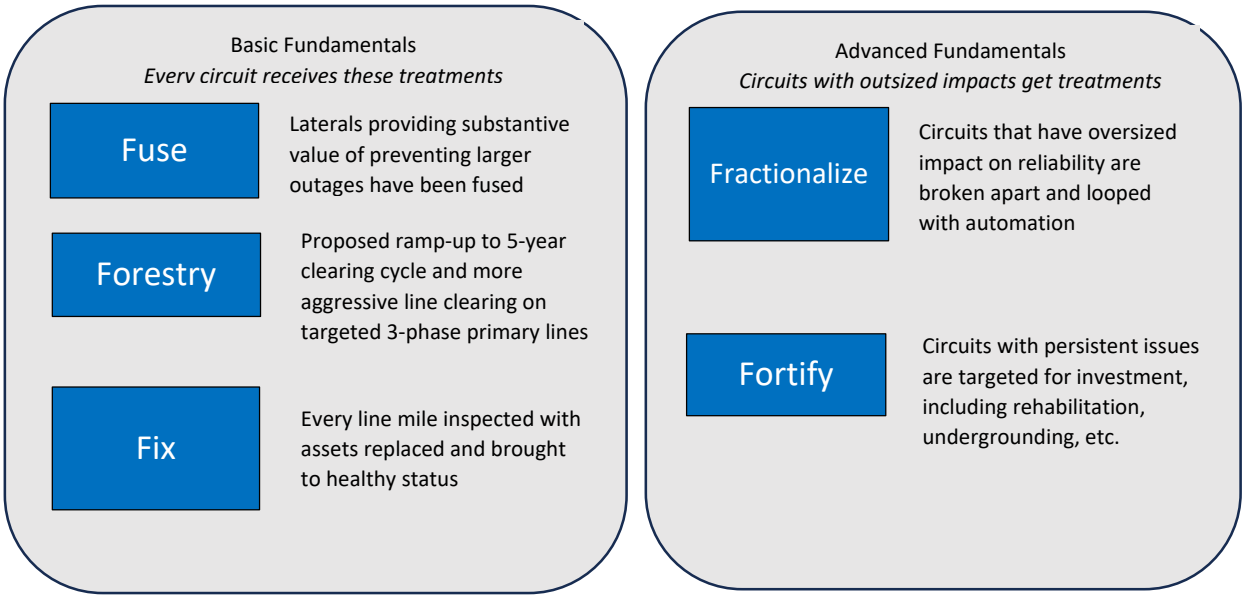
The Company's distribution system consists of several classes of assets. LVD lines, HVD lines, the Metro System, and substations were introduced earlier in the Distribution System Overview section of this report. In addition to these major classes, the distribution system also includes the protective system; distribution meters; distribution transformers; and streetlights.

The Company developed a strategic approach for each asset class to identify risks that affect reliability performance; developed countermeasures to mitigate those risks; created a workplan that implements those countermeasures in a prioritized manner; and defined an investment plan needed to support that work.

Each investment plan includes the planned Capital expenses to construct the distribution assets, and the Operations and Maintenance ("O&M") expenses for assets' annual inspections and upkeep, where applicable.

Each workplan is characterized by the Five Fundamentals Approach (Five Fs) shown in Figure 35 below, which succinctly covers the various approaches the Company uses to ensure reliable operations. By following this approach, the Company's investments are designed to improve system performance while ensuring circuits perform as expected.

FIGURE 35
FIVE FUNDAMENTALS APPROACH



The next several sections of this document will discuss the Company's specific asset management approaches for each asset class: LVD lines, LVD transformers and meters, Metro, HVD lines, substations, and system protection, plus additional topics like streetlights. In each case, the plan will outline the risks each subclass faces, a workplan tailored to address the most urgent risks, and the 5-year investment needs to execute this plan.

LVD Asset Management

LVD Lines Overview

This section focuses specifically on LVD Lines, which consist of several sub-classes of assets, each with a specialized asset management approach.

The entire distribution system contains approximately 107,000 miles of LVD lines, including 61,000 of Primary and 46,000 miles of Secondary as shown below in Figure 36.

FIGURE 36
LVD PRIMARY LINES MILES BY TYPE

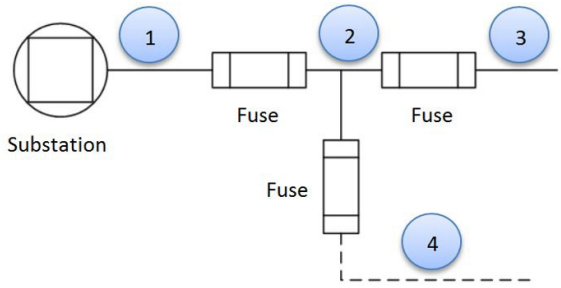
	Overhead	Underground	Total
LVD Primary Line Miles	51,736	9,885	61,621
LVD Secondary Line Miles	31,209	18,474	49,683
Total	82,945	28,359	111,304

In 2024, the LVD system comprised approximately 2,400 circuits, although some of these circuits are dedicated to a single customer or are part of the Metro system.

LVD circuits are subdivided into protective zones, as shown in Figure 37 below. As November 2024, the LVD system was apportioned into approximately 156,000 protective zones, with the number continuing to grow as the Company makes investments into the system to increase sectionalization and decrease the size of outages impacting its customers.

- Beginning in 2022, the Company set out to fuse overhead laterals to mitigate the size of outages by reducing the average number of customers out for an outage incident or event, lessening the impact of a fault to a smaller number.
- By the time this program is complete in 2025, the Company will have added approximately 28,000 fuses, reducing 41,000 customer outages annually and saving an estimated 9 minutes of SAIDI.

FIGURE 37
ILLUSTRATION OF CIRCUIT SUBDIVIDED INTO ZONES



Additionally, the LVD system includes approximately 1.5 million poles—1.1 million on the primary system, and 400,000 on the secondary system.

Based on the Company's historical data, the overall average lifecycle of an LVD primary circuit is expected to be 57 years. The average age of an LVD pole is 40 years.

The **largest reliability risks to the LVD lines system are those that lead to outages and interruptions to customers.** The two largest contributors to frequency of outages (measured by SAIFI) on the overhead LVD system are **trees and asset failures**.

Besides frequency of outages, **duration of outages (measured by CAIDI) contributes to LVD lines risk**. Much of this outage duration risk is addressed through the Company's Service Restoration efforts, but there are also outage duration implications of system configuration.

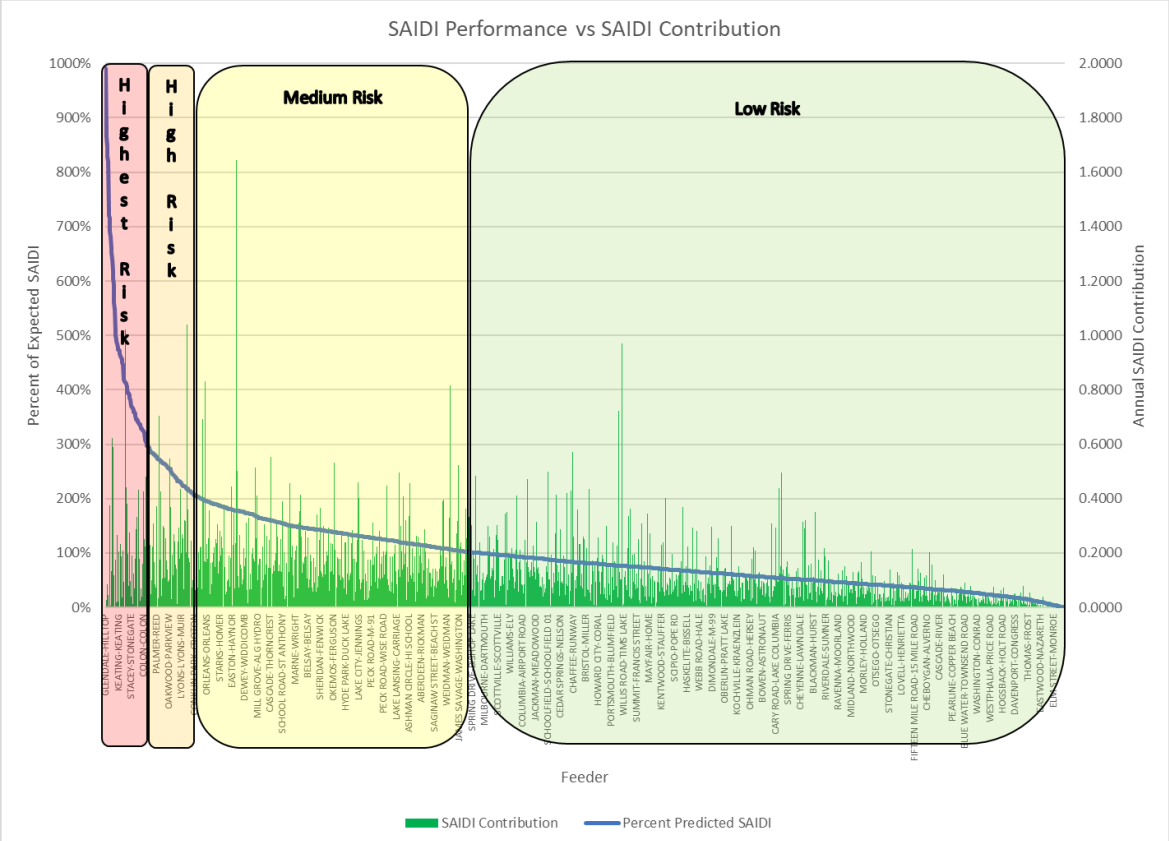
- The chart below in Figure 38 shows all LVD circuits within the Company's service territory on the horizontal axis with two measures of reliability performance on the vertical axis (the right side of the vertical axis shows actual SAIDI contribution, while the left side shows the percentage of expected SAIDI).
- The **100%** line on the vertical axis represents a circuit performing as it is engineered, while any green lines extending above this line represent circuits performing worse than expected.

Circuits on the left side of this figure, which present the highest risk to system performance if there is an outage, will need to be **Fortified** and in some cases **Fractionalized** to harden circuits against future risks and reduced in circuit line miles to minimize the impact of outages, respectively.

These approaches are detailed further in the Resiliency Investments section of this plan.

Circuits in the middle and right side of this figure that do not have an outsized impact when there is an outage may also be Fractionalized, but will primarily be addressed through **Fusing**, **Forestry**, and **Fixing** to improve the expected performance of most circuits, and are detailed further in the Reliability Issues and Investments for LVD Lines and Forestry Line Clearing sections of this plan.

FIGURE 38
LVD CIRCUIT SAIDI



LVD Safety-Focused Issues and Investments

The **greatest public safety risk from the LVD system comes from downed wires**, usually following weather events. Energized downed wires are dangerous and, if contacted, cause injury or fatality.

To mitigate this risk, the Company works to repair downed wires as soon as possible and has procedures to guard downed wires until they can be fixed (emergency responders will also do this, and the MPSC rules provide that the Company must relieve emergency responders in a timely manner).

The investments planned as part of the following LVD asset subclasses reduce this risk by preventing outages, downed wires, and other contact with energized equipment:

- Standardizing the Company's system voltages **through Voltage Conversions** to mitigate the safety risk from ungrounded wires and allow for quicker recoveries from outages.
- Removing **Subsurface transformers** to improve employee safety, avoid potential public contact and environmental contamination.
- Modernizing legacy **secondary distribution assets**, to provide a safer and more resilient final service to many customers after the final transformer.

Legacy open wire secondary presents a particular safety issue in the event of a downed wire because they are not well-insulated, are not always easily accessible to crews, and usually located in higher population areas.

Voltage Conversions

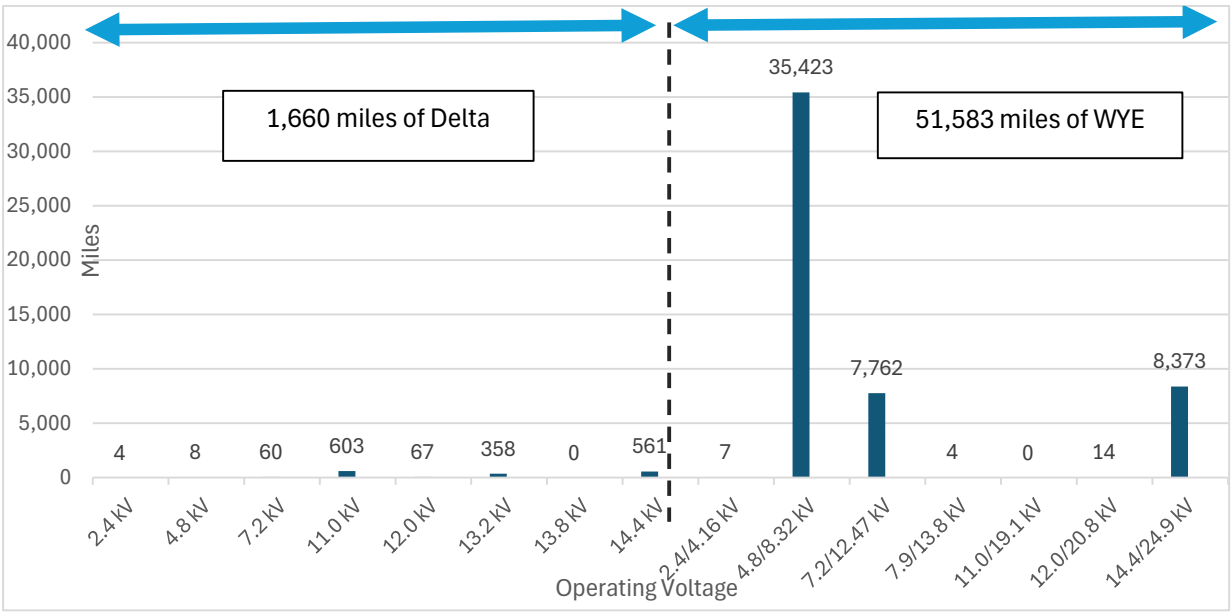
The Company's LVD system consists of 13 different voltages, a holdover from when the Company acquired smaller systems throughout its history.

Non-standard voltages restrict the Company's ability to install transfers between circuits and modernize the grid in a streamlined fashion because circuits of different voltages cannot be connected.

Figure 39 below, shows the Company's three standard voltages, which are 4.8/8.32 kV, 7.2/12.47 kV, and 14.4/24.9 kV, along with the 10 remaining non-standard voltages and associated overhead line miles.

Figure 39

OVERHEAD PRIMARY LINE MILES BY VOLTAGE AND CONFIGURATION



While only a fraction of the overall system, the 1,660 miles of Delta are less safe to operate compared to a grounded wye system.

- Delta systems require two phase ground faults to be present before the phase protective device trips, which means a downed Delta wire will not trip a primary protective device until a second phase fault develops.

By converting non-standard components to one of the three standard voltages, **the Company will mitigate the safety risk from ungrounded wires and increase operational flexibility** by expanding the ability to transfer loads to reduce outage times.

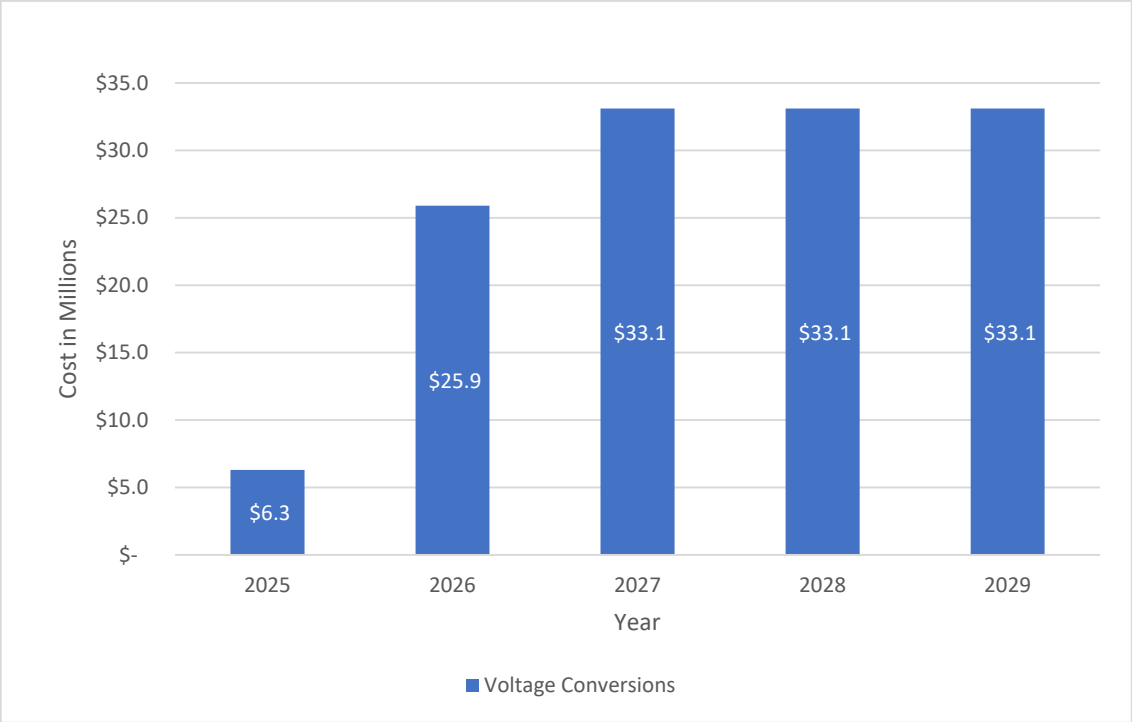
Additionally, voltage conversion will increase efficiency and reduce the operating costs through requiring lower levels of inventory to serve the variety of voltages.

The Company plans to invest $33 million per year over the next 10 years to convert at least 165 miles per year of non-standard voltage overhead lines, with an end goal of converting all non-standard voltages.

The next 5 years of spending for this plan is detailed in Figure 40 below.

Figure 40

VOLTAGE CONVERSIONS 5-YEAR INVESTMENT PLAN



Year	Miles of Nonstandard Voltage Converted
2025	33
2026	210
2027	268
2028	268
2029	268

Subsurface Transformers

Figure 41

FIELD VIEW OF SUBSURFACE TRANSFORMER



In 2023, the underground system had 159 of its original subsurface transformers, representing 0.15% of the transformers serving the underground system. At the end of 2024, there are 139 remaining.

While few in number and while not having a major impact on reliability, **subsurface transformers present a safety risk for Company employees, the public, the local environment, and grid reliability**.

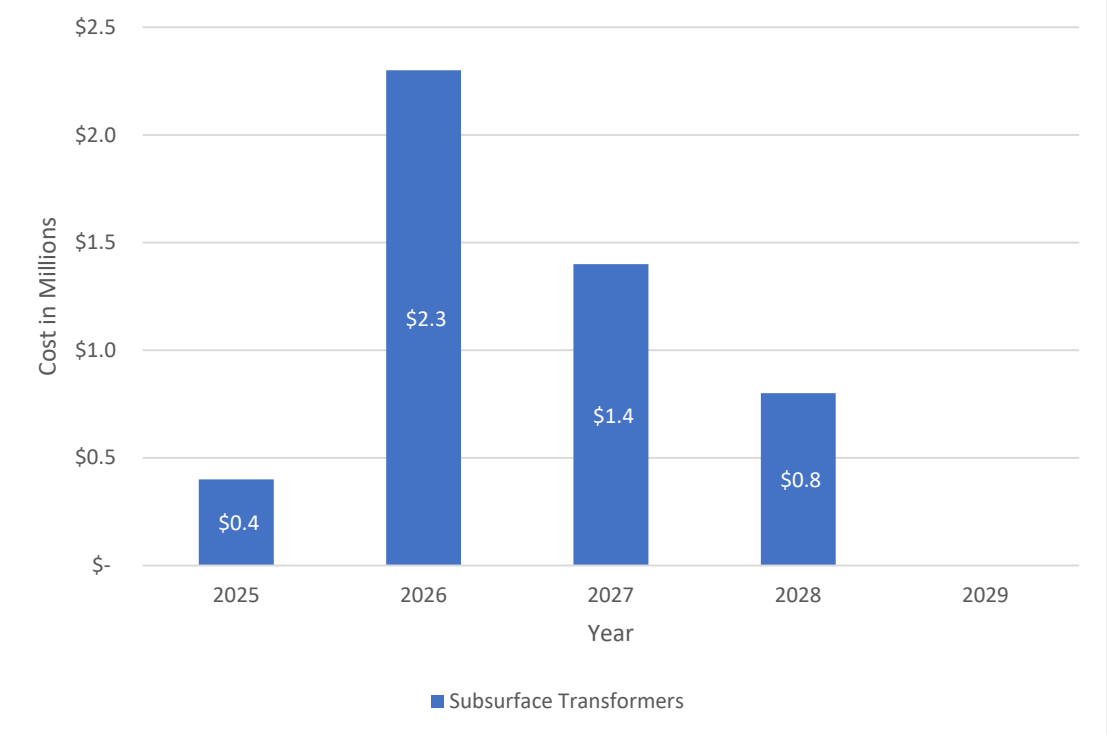
- Since these assets are located underground, Company employees have difficulty accessing and repairing them when they fail, leading to an outage lasting roughly four times longer compared to padmount transformers.
- The location makes it difficult for the public to recognize these transformers in the field, making it easier for them to come into contact with these transformers.
- Lastly, these transformers are more difficult to inspect when they do fail, making a subterrain oil leak more likely, contaminating nearby land and ecosystems.

To address this issue, the Company has begun proactively replacing all 159 subsurface transformers with padmount transformers, which are easier to inspect and repair. As of the end of 2024, there are 139 remaining on the system.

The 5-year investment plan is shown below.

Figure 42

SUBSURFACE TRANSFORMERS 5-YEAR INVESTMENT PLAN



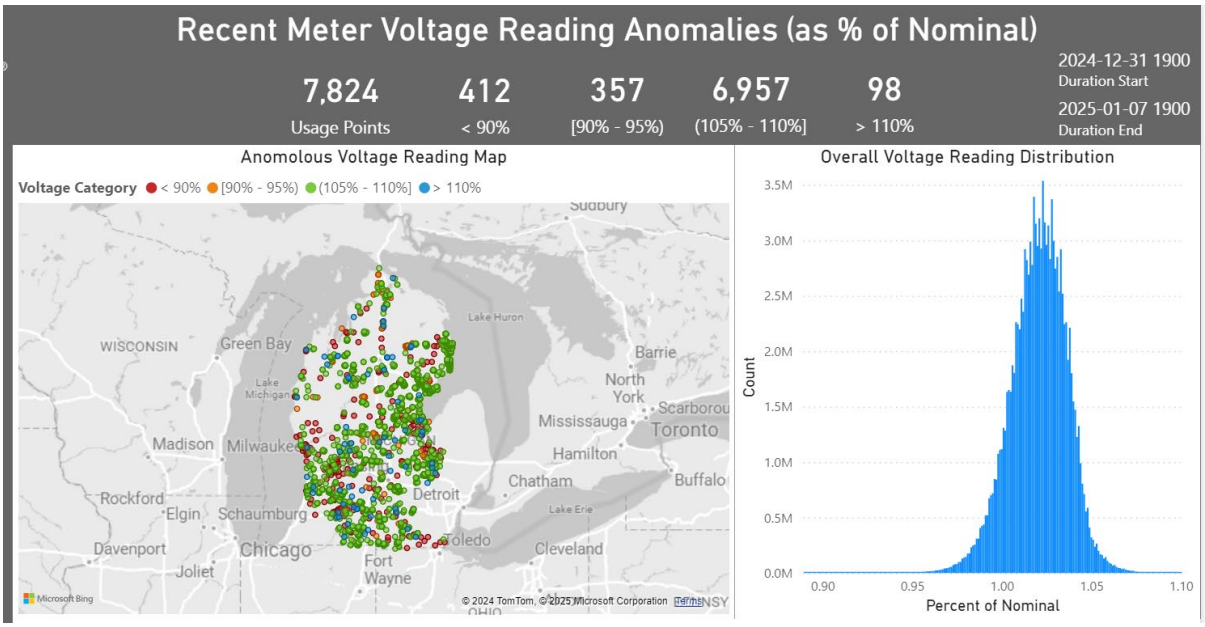
Year	Subsurface Transformers Replaced
2025	11
2026	40
2027	53
2028	35
2029	0

Meter Voltage Anomalies

The Company's AMI meters allow for continuous monitoring of customer service delivery point voltage levels. The criterion for acceptable voltage is outlined in Rule 702 of the MPSC Standards of Quality of Services, and in most cases is ±5% of nominal voltage. The vast majority (>99%) of service delivery points maintain this voltage level, as shown in Figure 43 below.

Figure 43

METER VOLTAGE ANOMALIES



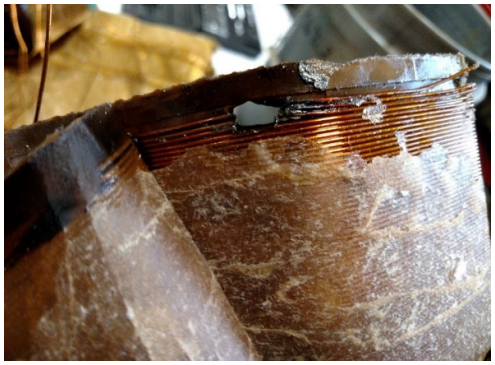
As shown in the histogram in Figure 43, the majority of voltage anomalies are 5% to 10% above nominal voltage.

After several years of investigating and reactively correcting these anomalies as they arise and are reported by customers, there are three main causes of voltage anomalies:

- Low voltage (<95% nominal) is typically due to heavily loaded secondary and line transformers
- Moderately high voltage (between 105% and 110% nominal) is typically due to voltage regulation device issues
- More extreme (>110% nominal) high voltage typically is due to internally faulted but still energized line transformers. These internal faults result in the transformer turns ratio being altered, creating sustained high voltage on the load side of the transformer. Figure 44 below shows an example of this type of failure that requires replacement of the line transformer.

Figure 44

INTERNALLY FAULTED LINE TRANSFORMER



While the Company has been addressing meter voltage anomalies on a reactive basis as they are identified by customers, the Company is now planning to proactively address them, using AMI data to identify noncompliant locations.

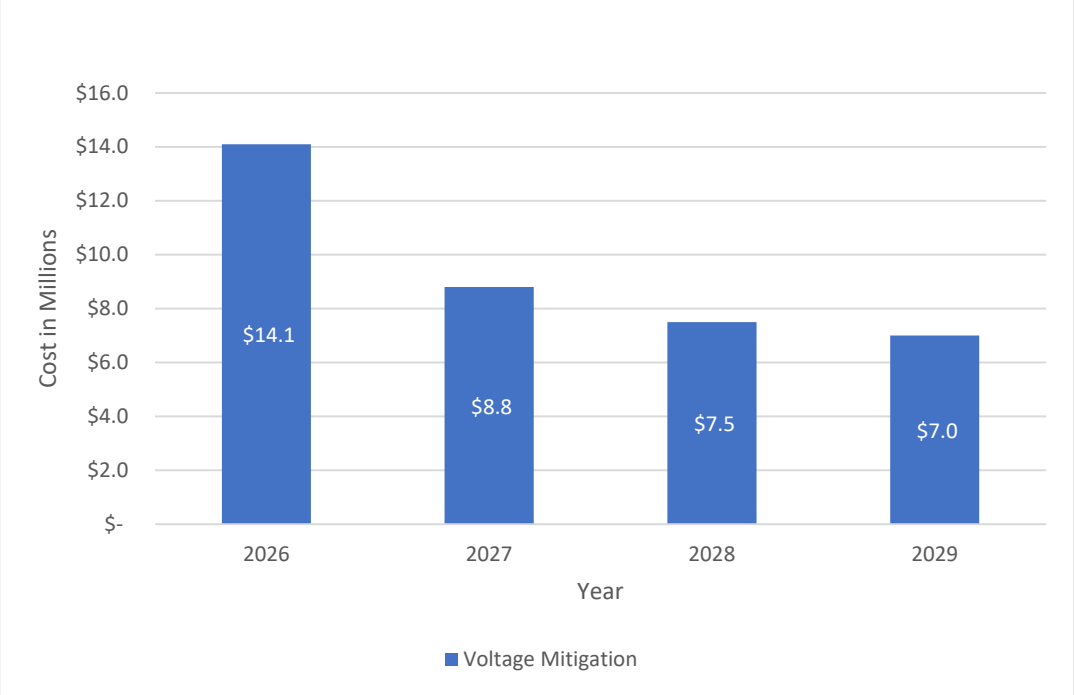
In many cases, particularly where voltage is low, AMI data should let the Company identify locations even before customers recognize that their voltage is out of compliance.

The Company projects that, over the next five years beginning in 2026, it will need to complete the work shown in Figure 45 to address meter voltage anomalies on the system.

FIGURE 45

METER VOLTAGE ANOMALIES 5-YEAR INVESTMENT PLAN

Year	Line Transformers Replaced	Regulator Mitigations	Low Voltage Mitigations (Secondary Miles)
2026	650	125	25
2027	300	100	15
2028	300	75	15
2029	300	50	15



Secondary Circuit Assets

Secondary circuit assets are located between the distribution transformer and customer meter. Repairs are more challenging than primary repairs for crews for various reasons.

- In urban areas—in many cases in EJ communities—the secondary is typically located behind homes in backyards instead of roadside. When secondary is behind the home instead of roadside, it is more difficult to access with a bucket truck (e.g., along property lines with fences without an ally way) and may require Forestry assistance to access.

- Of the 31,000 miles of secondary on the Company's system, 27,000 miles are multiplex, and 4,000 miles are open wire. Examples of multiplex and open wire secondary are shown below in Figure 46.

Open wire secondary is more challenging to repair than multiplex secondary because breaks often occur mid-span, and if bucket truck access is not possible, repairs require splicing on the ground and then routing the conductor through trees.

- Much of the open wire secondary is nearing or at the end of its life, which causes the conductor to be brittle and not easily repaired.
- Open wire secondary is also more vulnerable to tree damage than multiplex. In general, the solution to issues with open wire secondary is to convert it to multiplex.
- Secondary outages occur at an average of 10 outages per day across the state and affect, on average, 3 customers per outage.

FIGURE 46
MULTIPLEX VS. OPEN WIRE SECONDARY



The factors that make secondary repairs more challenging contribute to higher average outage durations with an average duration of more than 10 hours. **These long response times present a risk to public safety, since wires are down for longer periods of time.**

These long duration, high frequency outages also cause the Company's line crews to spend more time, at a higher cost, to address emergent outages at the expense of planned work to proactively improve system reliability.

Outages overnight cause crews to have delayed start times, which further reduces the amount of planned work the Company can complete. They also drive costs higher as the repair work is done on overtime. Approximately 13% of secondary repairs are made during overnight hours.

The reliability and safety risks associated with secondary are particularly important for EJ communities.

- Approximately 18% of the Company's secondary in EJ communities is open wire. The long duration nature of secondary outages has a heightened impact on EJ communities, where customers are less likely to have back-up power generation, and experience financial and health impacts from long outages more acutely.
- Secondary in EJ communities tends to be in high population areas. This further increases the risks associated with downed wires.

A key benefit to secondary replacement is that it includes installing larger secondary conductors with more capacity, in anticipation of future electric vehicle loads and rooftop solar installations.

Installing larger secondary conductors will reduce the number of future upgrades required for our customers when they adopt new technologies.

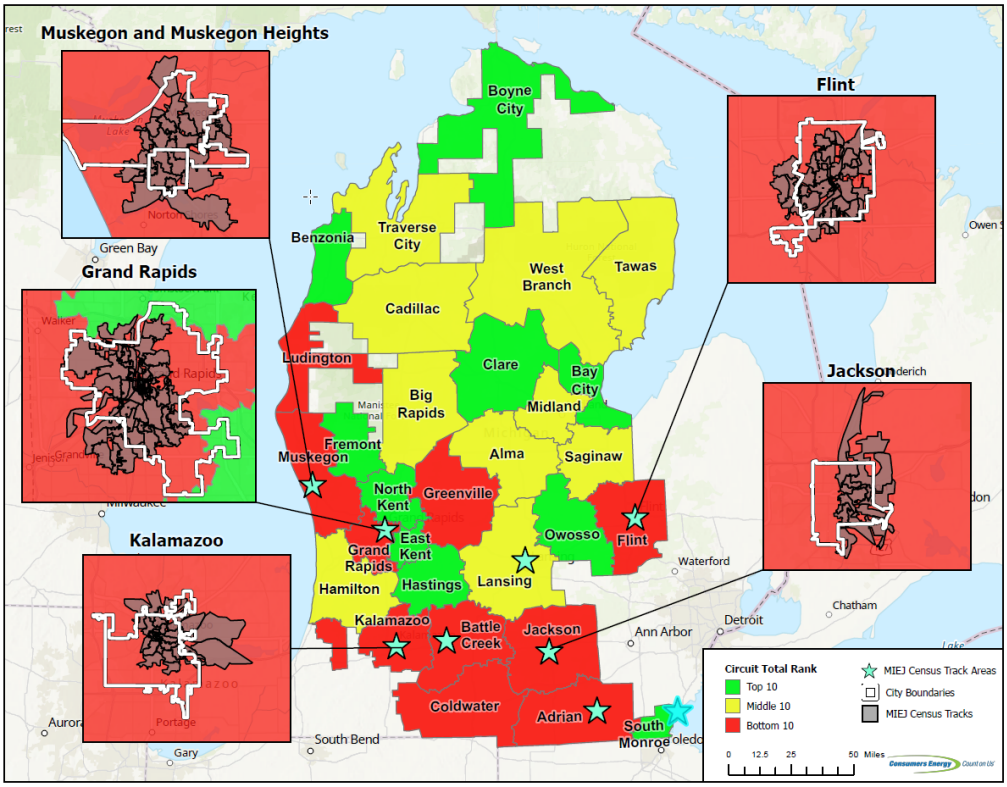
The Company measures secondary asset health through a combination of impacts to customers and number of interruptions.

In Figure 47 below, the Service Center regions with the worst performing secondary across the Company's service territory are highlighted in red.

As the map shows, many of the regions with the worst performing secondary contain high concentrations of urban areas and EJ communities. Focusing our investments in these areas will result in the greatest cost benefit for improving reliability while investing in EJ communities.

Figure 47

WORK HEADQUARTERS WITH MIEJ CENSUS TRACK



When open wire secondary is replaced with multiplex secondary, reliability increases.

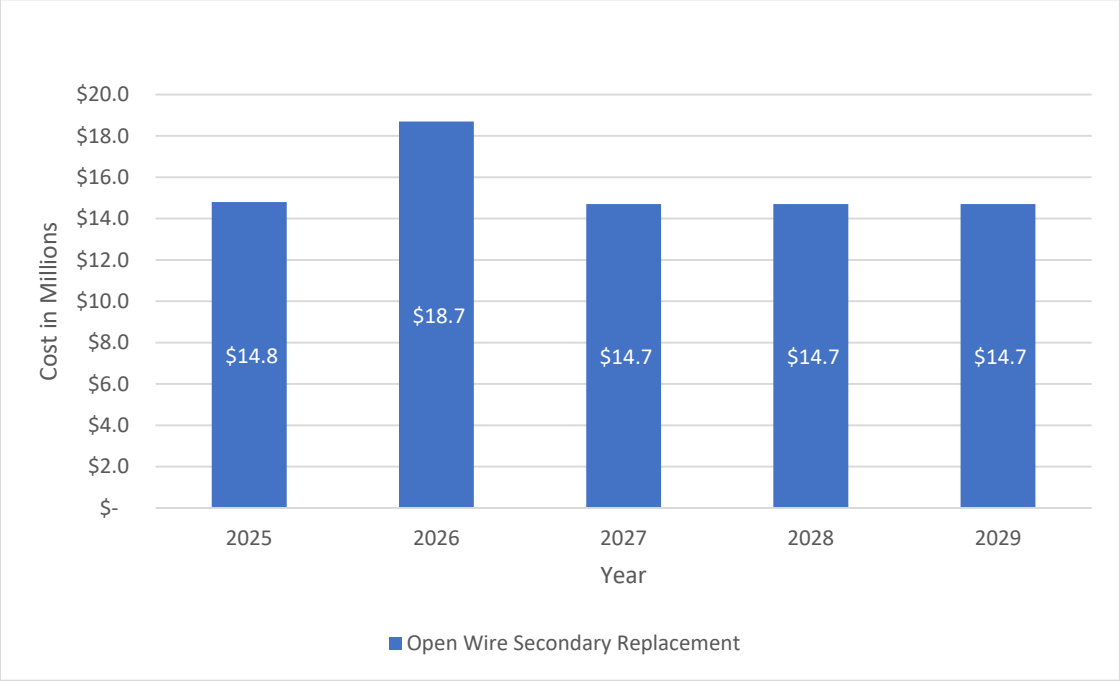
- Although the SAIDI impact of open wire secondary is not large, replacing open wire secondary is still beneficial. It reduces local outages, improves local CEMI and CELID metrics, facilitates employee training, and most importantly, reduces the risk of downed wires.

To address issues relating to open wire secondary, the Company is accelerating replacement of open wire secondary with a program of targeted replacements for the worst-performing circuits.

The Company plans to invest approximately $14.7 million per year over the next 10 years on the worst-performing secondary circuits in its territory, as detailed in Figure 48 below.

Figure 48

OPEN WIRE SECONDARY REPLACEMENT 5-YEAR INVESTMENT PLAN



Year	Miles of Open Wire Secondary Replacement
2025	50
2026	63
2027	50
2028	50
2029	50

Wildfire Risk Mitigation

As part of delivering safe and reliable electricity to customers, the Company must address the growing wildfire risk brought on by changing climate in Michigan[7].

Over the last decade, wildfires have grown in number and severity throughout the United States, and become a significant public health and safety concern. In the last 13 years, there have been more than 100 wildfires in the Lower Peninsula each year, burning more than 2,000 acres in seven of those 13 years and more than 2,000 acres in three of the last four years.[8]

Given these trends, the Company developed a wildfire risk mitigation plan for its electric territory. This plan is a separate document that is provided concurrently with this updated Reliability Roadmap in Case No. U-21870.

This plan describes the Company's approach to mitigate the risk of wildfires caused by or impacting electrical infrastructure and surrounding communities throughout Consumers Energy's service territory, with safety as the top priority.

It outlines the steps the Company is taking or plans to take to develop competencies, invest in system hardening, and expand existing programs such as line clearing to alleviate the pressure from increased wildfire risk, all to improve the safety of customers, communities, and employees.

This plan will continue to evolve as the Company learns more about wildfire risk in Michigan, new wildfire risk reduction strategies and technologies, and how changing weather patterns impact the region.

As part of its wildfire risk mitigation plan, the Company intends to:

- Understand the current and probable wildfire risk areas in our service territory through development and maturity of assessment tools.
- Implement mitigation solutions that balance the risk of wildfires with safe and reliable energy delivery.
- Leverage existing programs, such as line clearing, to deliver benefits beyond reliability and resiliency.
- Implement procedures to inform customers and communities of wildfire preparedness measures and communication protocols in the event of a wildfire risk event, i.e., *Red Flag Warnings*.
- Engage customers and communities in the ongoing development of the wildfire risk mitigation plan, particularly as it relates to ensuring customer safety and electric reliability.
- Continuously improve this plan by leveraging industry experts and peers and learning about and deploying best practices.

[7] Wildfire Weather: Analyzing the 50-year shift across America, May 2023 - www.climatecentral.com
[8] Michigan Department of Natural Resources - Fire Report Dashboard

Reliability Issues and Investments for LVD Lines

The Company makes planned investments in its LVD lines to improve reliability through the reduction of outage risks by:

- Identifying and mitigating problems with primary conductor, poles, and other supporting components through **Targeted Circuit Health Improvements** and addressing the worst-performing areas of the system.
- Replacing and upgrading deteriorated **LVD poles that** perform better in under extreme weather.
- Upgrading **overloaded components** to prevent overload-caused outages.
- Rejuvenating and replacing deteriorated **LVD Vintage underground cable**.
- Promoting safety, efficient operations, and aesthetics in the downtown areas of Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw through the **Metro system.**

The Company also works through its **Forestry Line Clearing Program** to mitigate tree-related outages, which are the biggest external risk factor for LVD Lines. (Forestry Line Clearing also addresses tree-related risk on HVD Lines.) Forestry work, which is largely O&M, is discussed in the **Forestry Line Clearing Program** section of this document.

Inspection and System Maintenance

The Company is reducing reliability and safety risks through inspection and maintenance programs recommended by the *IEEE*.

The Company is proposing the following schedule, shown below in Figure 49, based on good engineering practice to help identify and correct problems before they result in outages.

FIGURE 49
LVD O&M INSPECTION CADENCE

Inspection Task	Cadence	Components Checklist	Annual O&M Cost
LVD Line Inspections	2 Years	• Visual Inspection of pole and pole top components. • If a pole is suspected of failure perform test for strength.	$125K
Padmount Inspections	Significant Sample Annually	• Visual external safety inspection to identify if secure, holes or leaking.	$500K
Electronic Circuit Recloser	Remote Monitoring	• Monitor for any abnormality in performance and investigate for correction.	$400K
	4 years	• Replace battery and inspect reclosers without modems for any abnormality in performance and correct as abnormalities are identified.	$425K
Switched Capacitor Bank	Remote Monitoring	• Monitor for any abnormality in performance and investigate for correction.	$300K
Gang Operated Switches	3 Years	• Inspect and cycle the switch to ensure proper performance and correct as abnormalities are identified.	$450K
Disconnect Switches	4 Years	• Inspect, cycle and clean contacts to ensure proper performance and correct as abnormalities are identified.	$3.5M
Total			**$5.7M**

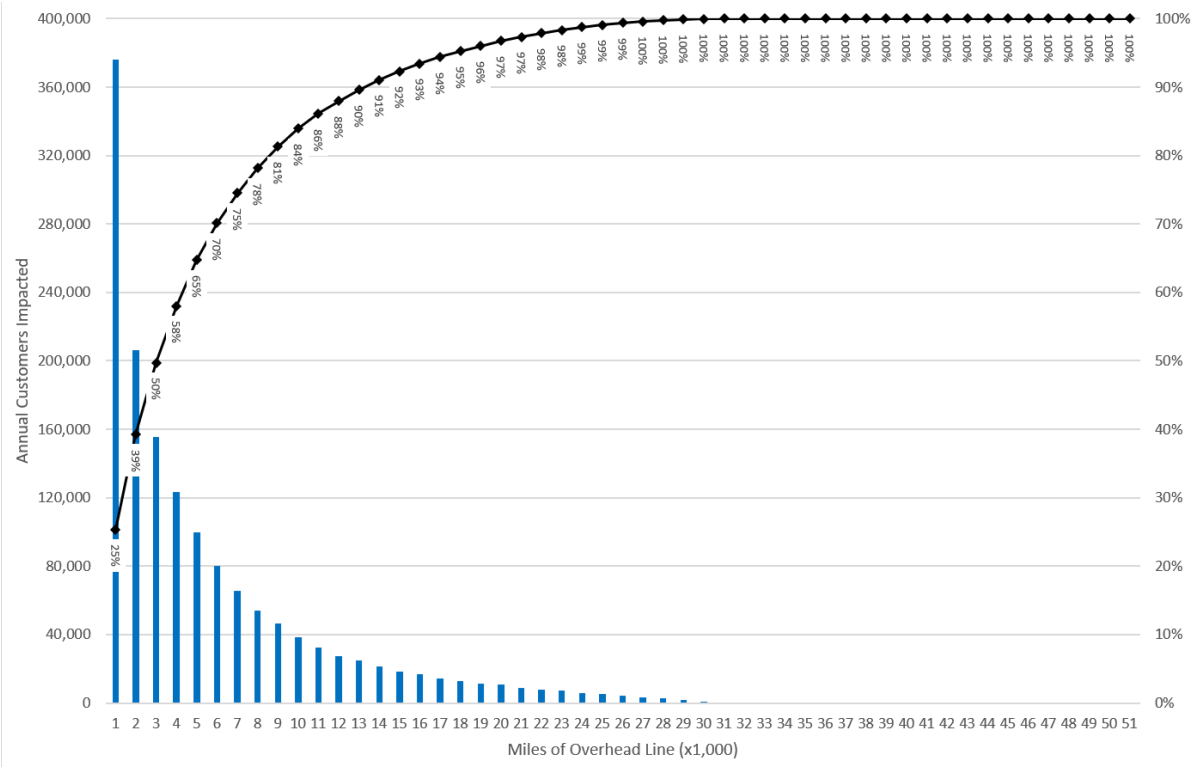
Zonal Health Assessments

In assessing LVD lines asset health, the Company has found that 91% of customer interruptions happen on just 25% of system miles, as shown in Figure 50.

Because of this, **the Company focuses on protective zones when assessing asset health and mitigating risk,** rather than on whole circuits. This enables the Company to focus on those parts of the system causing the most interruptions.

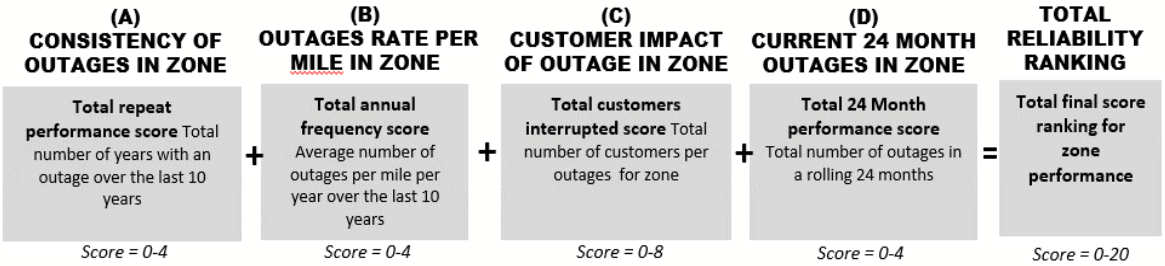
Furthermore, by focusing on the zones with the worst health, the Company can improve the reliability of customers downstream from the zone, not just the customers directly in the zone.

FIGURE 50
SYSTEM OVERHEAD MILES RANKED BY CUSTOMERS IMPACTED
(2015-2024)



When the Company assesses zonal health, it uses a 20-point scale based on inputs from the Reliability Analytics Engine, with four data points driving the score. These are shown in Figure 51 below.

FIGURE 51
ZONAL HEALTH ASSESSMENT SCORING RUBRIC



- Of the Company's approximately 156,000 total zones, approximately 22,000 of those zones currently have a score; the remainder do not have a score, which means they have had no outage activity at all for at least two years.
- In other words, more than four-fifths of zones on the system are working as intended and do not need to be prioritized for any investment at all at this time.
- The Company has found that customer interruptions in a zone begin to increase exponentially once the total zonal health score exceeds 10 and gets particularly severe once the score exceeds 15.
- Of the approximately 22,000 zones that currently have a zonal health score, just over 7,800 of them have a score of 10 or higher, representing approximately 4.5% of the Company's total LVD system.

When the Company identifies poor-performing zones on LVD circuits, it designs a zonal health investment project to address one or more zones to resolve the problem.

- Zonal health investments can include replacing equipment at end of life, hardening existing assets, installing new system protection devices like fuses and reclosers, and improving the capability to isolate and transfer load. Taken together, all these actions reduce the probability of an outage.
- Zonal health investments have consistently delivered reliability benefits for the LVD system because these under-performing zones have been strategically selected for rehabilitation.

As shown in Figure 52 below, SAIDI improves substantially following the completion of zonal health investment projects.

FIGURE 52
SAIDI IMPROVEMENT FOLLOWING ZONAL HEALTH INVESTMENTS

Project Year	Zonal Projects	% Improvement Prior 3 years Post improvement
2017	147	51%
2018	138	57%
2019	151	66%
2020	146	71%
2021	249	62%
2022	1,394	40%
2023	2,884	28%
Weighted Average Improvement		**64%**

It is important to note that the "zonal projects" column includes fusing work in 2022 and 2023 in addition to more traditional zonal health improvement work, which is why the number of projects increases by so much.

Fusing projects do not necessarily reduce the number of outages on a circuit, but they do reduce the number of customers impacted by any particular outage. This impacts the before and after outage numbers in the figure, and therefore the calculated percentage improvement.

Please note that traditional zonal health improvement work delivers substantial outage reduction benefits, as shown in the data from 2021 and earlier.

In addition to zonal health investments, the Company also installs ATR loops on the LVD system to automatically restore power to customers when an outage occurs. This is described later in this report in the section on Resiliency Investments.

LVD Zonal Health Investment Plan

The Company plans to address all zones with scores of 10 or greater, since interruptions to customers begin increasing exponentially once the zonal health assessment score exceeds 10 out of 20. This will require targeted zonal health investment projects for each of these zones.

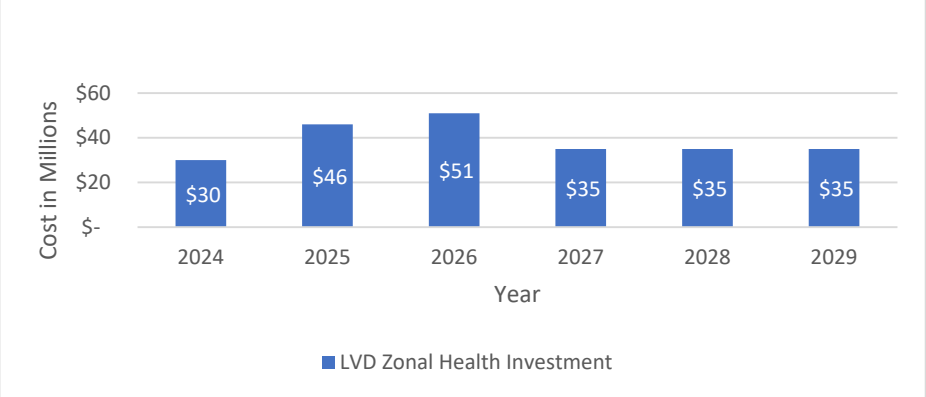
At present, the Company plans to address an average of 85 zones per year.

The Company will rank zones from worst to best by zonal score, and address zones in that order, periodically reprioritizing to ensure that the Company's workplan is continually targeting the worst-performing zones.

The 5-year investment plan for LVD zones is shown below in Figure 53.

Figure 53

LVD Zonal Health 5-Year Investment Plan



Year	LVD Zones Addressed
2025	110
2026	340
2027	85
2028	85
2029	85

LVD Pole Health Assessment

As noted earlier, the average age of an LVD pole is 40 years. Pole failures take roughly twice as long to replace compared to replacing damaged pole top equipment, such as pins or wood crossarms.

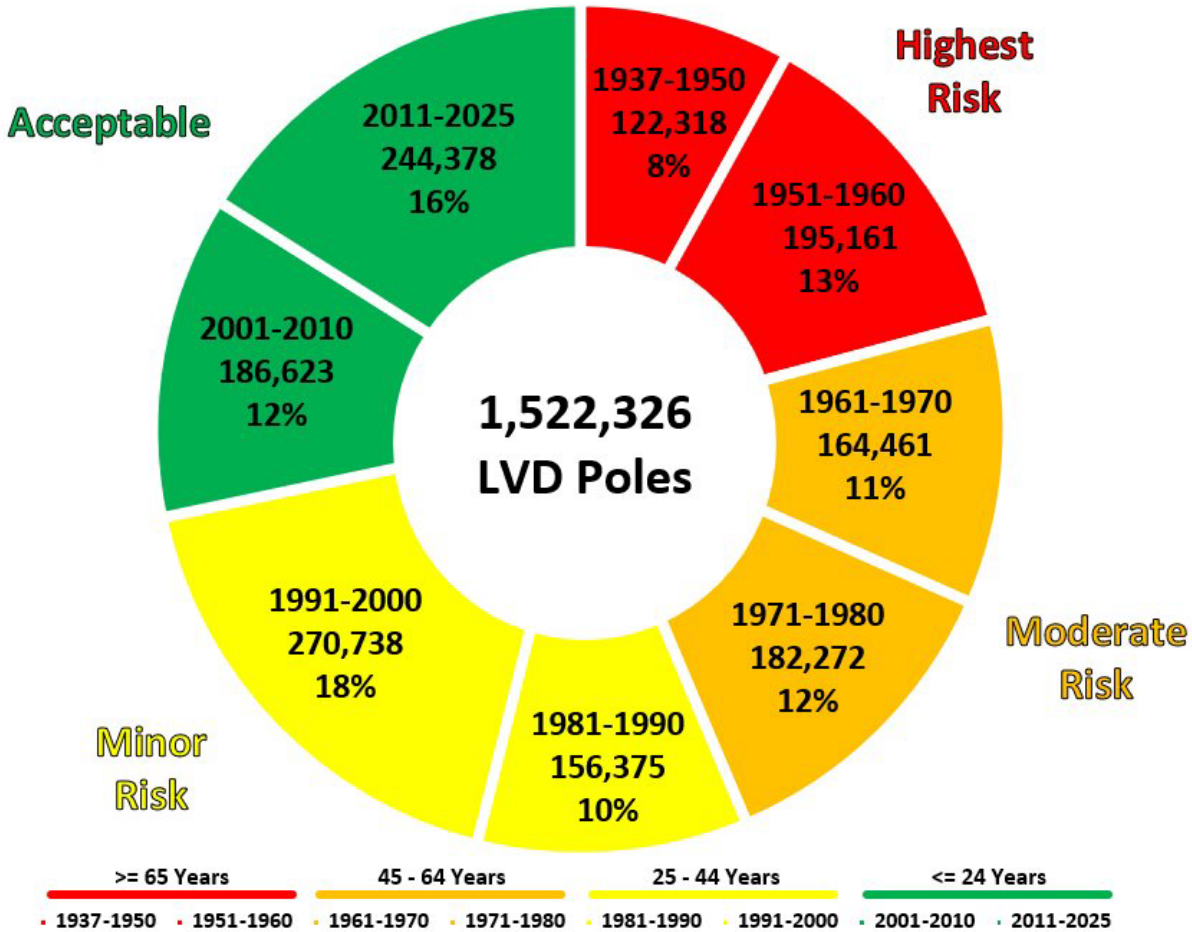
Additionally, underground facilities need to be located by an outside agency prior to digging for safety reasons. These locate requests can take up to three hours in an emergency.

According to *National Electric Safety Code* ("NESC") standards, if a pole deteriorates to below two-thirds of its original install state, it is classified as "rejected" meaning the pole is more vulnerable to failure in car-pole accidents or by high winds, ice, trees, or other external factors.

Figure 54 below shows the number of poles on the LVD system by the decade in which they were installed, with the corresponding risk level for each vintage. The Company expects that the highest risk poles have a >15% rejection rate, the moderate risk poles have a 10%-15% rejection rate, and the minor risk and acceptable poles have a <10% rejection rate.

Based on this information, the Company estimates that 10% of the system, or approximately 150,000 poles, would be classified as rejected.

FIGURE 54
NUMBER OF LVD POLES BY VINTAGE



The Company is working to reduce risk from poles by performing visual security inspections, and replacing the most urgent poles identified from the pole inspection program. The Company is also beginning a groundline inspection program to inspect all poles on a 12-year cycle.

To build a more resilient system while aligning with industry standards, the Company has changed the minimum standard pole classes to provide greater capacity for LVD overhead lines and a more reliable outcome for the future.

- The Company went from Class 6 to a Class 3 for our primary applications starting in 2021, which will increase capacity by nearly 200% as shown in Figure 55 below.

Figure 55

2023 NESC CODE[9]

No Significant Pole Deterioration as Noted in NESC Table 261-1			
NESC Grade C Construction - LVD - NESC 250C&D Load Factors			
Pole Size Minimum	No ICE, Max Wind Speed Prior to Failure (mph)	½ Inch Ice, Wind Speed Prior to Failure (mph)	1 Inch Ice, Wind Speed Prior to Failure (mph)
Class 6	109 mph	54 mph	39 mph
Class 5	116 mph	57 mph	43 mph
Class 4	129 mph	64 mph	49 mph
Class 3	141 mph	71 mph	54 mph
Class 2	157 mph	79 mph	60 mph
Class 1	170 mph	86 mph	67 mph

The largest impact of this change is when the Company replaces existing poles in the field that failed during storm restoration and were originally sized using smaller pole class minimums, or for new overhead line construction.

Based on the larger number of LVD distribution lines, it is estimated that 2-3% of our overhead LVD distribution system is replaced or newly installed with this new standard each year.

Additionally, poles are regularly replaced as a component of targeted zone improvement projects, plus other programs like Asset Relocations and New Business.

LVD Pole Investment Plan

Starting in 2025, the Company will initiate a groundline inspection program to identify and replace all rejected poles on a 12-year pole inspection cycle and inspect 125,000 primary and secondary poles each year.

- The Company will inspect a minimum of 50,000 poles in 2025, though if time and capabilities permit, up to 125,000 poles may be inspected. The Company plans to ramp up to where it consistently performs 125,000 pole inspections per year.
- Using the historical 10% rejection rate, the Company expects approximately 12,500 poles will need replacement each year, at least once the Company hits its full stride of performing 125,000 annual inspections. The inspections will cost $3 million annually in O&M spending.
- During the Company's regular 2-year circuit inspection cycle, the Company will continue to visually inspect poles and replace them as needed.

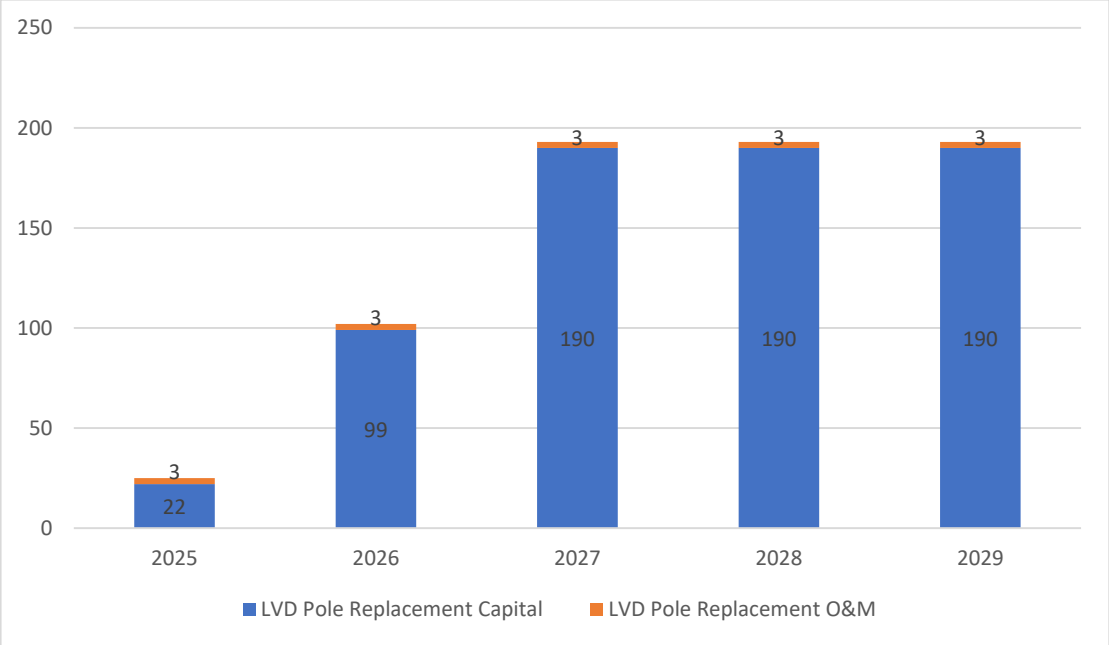
[9] 2023 NESC, linear analysis, 1/0 ASCR 3 phase conductor with #4 ACSR Neutral, 350-foot spans, 45-foot pole lengths.

Altogether, this replacement plan based on groundline inspections will identify and replace approximately 12,500 poles annually and will cost approximately $190 million in capital spending per year.

The investment plan for LVD poles is shown below in Figure 56.

Figure 56

LVD POLES INVESTMENT PLAN ($000S)



Year	LVD Poles Replaced
2025	2,300
2026	9,700
2027	12,500
2028	12,500
2029	12,500

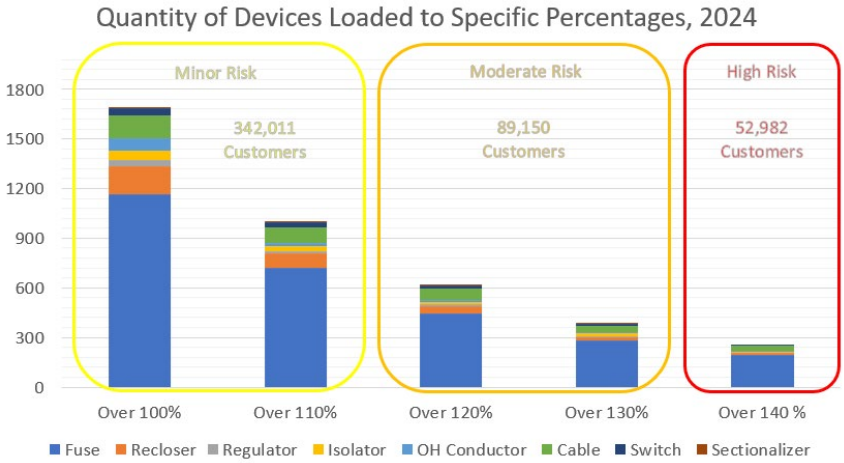
LVD Overload Risk Reduction

The LVD system also faces risks related to components overloading driven by local load growth.

When a component fails due to being overloaded, it results in an unplanned outage. These unplanned outages generally take longer to restore than planned outages, increasing SAIDI. The risks to customers due to component overloads are shown in Figure 57 below.

FIGURE 57

QUANTITY OF COMPONENTS LOADED TO SPECIFIC PERCENTAGES, SUMMER 2024



In general, individual components can withstand loading to greater than 100% of their rating for relatively short periods, such as a few hours on a hot summer day, but if overloaded too long or too frequently, they begin to deteriorate, introducing the risk of overload-caused customer outages.

Any component has a loading at which it will absolutely fail; these vary by component type, but the Company classifies components at the highest risk if they are projected to exceed 140% loading.

Components in the medium and high-risk categories may be able to continue operating normally if they are not regularly loaded past the 100%-130% range, as the components are designed to operate with that loading for short periods. However, those components still face risk because a modest increase in load, such as from an increase in EV penetration nearby, could quickly load those assets to 140%.

Ideally, the Company's investment plan will address any components that are loaded higher than 100% in order to fully mitigate the risks of overloads and eliminate overload-caused outages on the system

Of the overload-related risks on the LVD system, **isolators present the highest risk** because they are complex to replace, stock is limited, and outages tend to be for extended durations.

- Isolators are a specific type of transformer used to convert one primary voltage to another primary voltage.
- If an isolator fails due to an overload, it can create an extended duration outage.
- For comparison, a failed fuse can be replaced very quickly by crews throughout the state, which all maintain a sufficient inventory of fuses.

The number of isolators at risk is shown in Figure 58 below. Summer 2024 load data show there were 9,469 customers at Medium Risk level or greater of experiencing an outage due to overloaded isolators.

The Company intends to address overloaded isolators on the grid over the next 10 years to mitigate this risk to customers.

FIGURE 58

QUANTITY OF ISOLATORS LOADED TO SPECIFIC PERCENTAGES, SUMMER 2024



In addition to replacing overloaded isolators, the Company is replacing other overloaded components through its *LVD Lines Capacity Investment* subprogram, prioritizing projects based on the projected overload for the specific component and on a dollar-per-customer impacted basis.

The Company develops project proposals once components get loaded above the levels identified in Figure 59 below.

FIGURE 59

LOADING CRITERIA FOR OVERLOAD RISK REDUCTION

Device	Loading Criteria
Conductor	100%
Fuse	130%
Hydraulic Recloser	100%
Electronic Recloser	100%
Regulator/Booster	100%
Isolator	100%

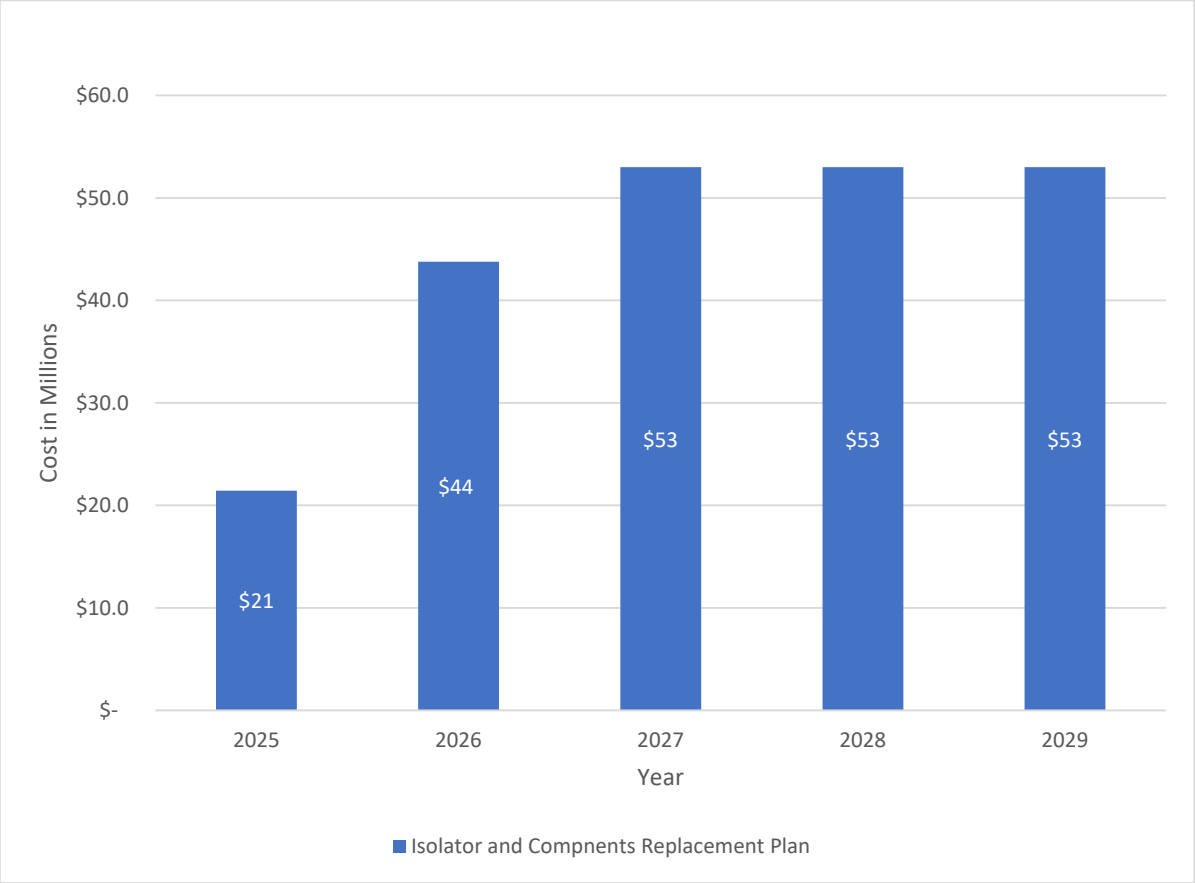
LVD Overload Risk Reduction Investment Plan

The Company will address all the isolators and other components currently loaded at or above the component-specific planning criteria.

The 5-year investment plan for LVD Overload Risk Reduction is in Figure 60 below.

FIGURE 60

LVD OVERLOAD RISK REDUCTION INVESTMENT PLAN



Year	Isolators Replaced	Components Replaced
2025	6	40
2026	8	52
2027	11	68
2028	10	67
2029	9	66

As discussed in the Challenges from Customer Technology Adoption section, load-impacting technology adoption could greatly exceed present levels, depending on consumer behavior, leading the Company to anticipate where customer adoption is most likely.

Specific to EVs, the Company has completed studies to determine where residential EV charging is likely to occur by examining the likelihood of a customer having an EV based on several factors including income level, and customer proximity to another EV. Based on this user profile, the Company predicts the circuits with the highest density of EV adoption over the next 4 years and will continue to re-evaluate further in the coming years.

While historically EV adoption has been in higher income areas, the Company expects to see increasing adoption across all segments, given developments such as the used EV tax credit, the increasing range of EVs and low battery degradation over time, and more EV models coming to market in general.

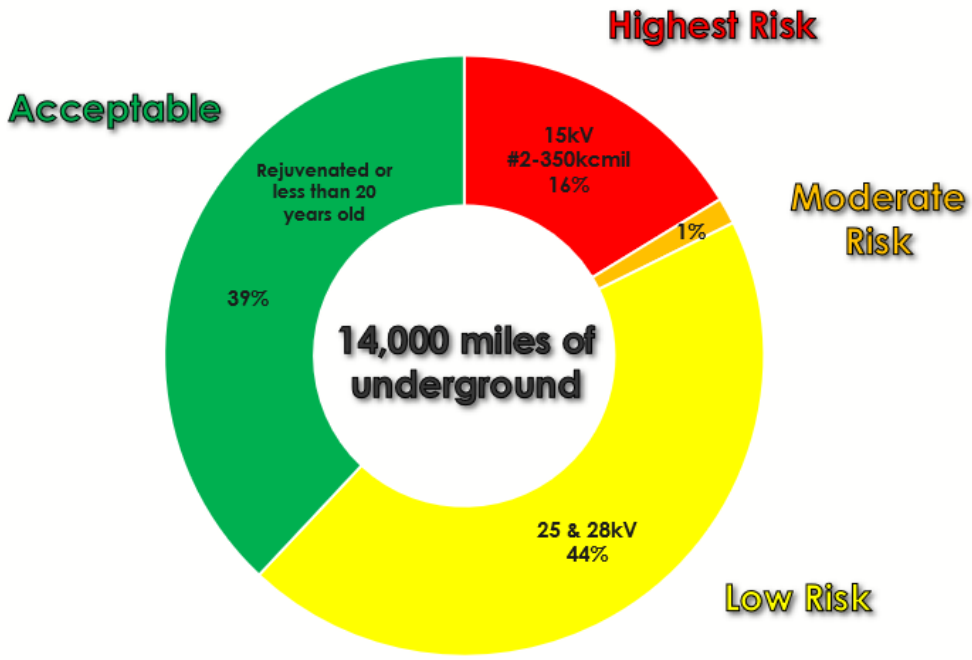
LVD Vintage Underground Cable

There are unique risks applicable to the underground primary system. While underground cable has historically lasted beyond its expected lifespan, vintage underground cable does present a heightened risk of failure.

- Out of a total of approximately 14,000 miles of underground primary cable (that equates to 9,500 system line miles), the Company has an estimated 2,500 miles of 15 kV underground cable dating to before the 1980s.

Figure 61

LVD Vintage Underground Cable Risk



- As this underground cable ages, the insulating material begins to degrade, reducing the remaining service life of the cable. This at-risk cable is also unjacketed, leaving the neutral conductors exposed to accelerated deterioration from direct exposure to external elements, such as soil and moisture.

The Company has recently begun using cable injection to rejuvenate cable, initially rolling this approach out in the Grand Rapids and Flint communities.

Cable Rejuvenation is *the process of taking a cable out of service, performing neutral and air flow testing, injecting a fluid like insulation that solidifies over time, and then putting the cable back into service,* all **at a lower cost than replacing the cable with new**.

- Any cable that fails the testing portion of the process gets replaced with new, jacketed cable.
- Approximately 2,300 miles of the 2,500 miles is smaller cable serving residential subdivisions and small commercial businesses and is eligible for cable rejuvenation.

A third-party contractor performs cable rejuvenation work, and it is most cost-effective to have this contractor complete all work in one area before moving on to other parts of the system. Therefore, the Company has targeted the work in only two communities at this point—Grand Rapids and Flint, with projects planned additionally in the Traverse City area in 2025.

The Company plans to continue targeted 15 kV underground cable rejuvenation; prioritization is based on which underground zones have the worst zonal health scores as explained earlier in the LVD Zonal Health Investment Plan section. Additionally, project selection considers feedback from the Company's electric crews who provide insight into repetitive repairs or field conditions.

Cable that is not eligible for cable rejuvenation, whether because of size or insulation properties, requires additional funding for replacement as it also begins to approach end-of-life expectancy. Thus, as insulation properties of underground cables have improved due to advances in technology and manufacturing capabilities, the ineligible cable must be replaced instead of rejuvenated.

In addition to vintage underground cable rejuvenation, **the Company is planning an aggressive program to convert overhead lines to underground** to mitigate the risks from severe weather, and dramatically improve the resiliency of its electric grid. This program and its associated costs and benefits are detailed in the Resiliency Investments section of this report.

LVD Vintage Underground Primary Investment Plan

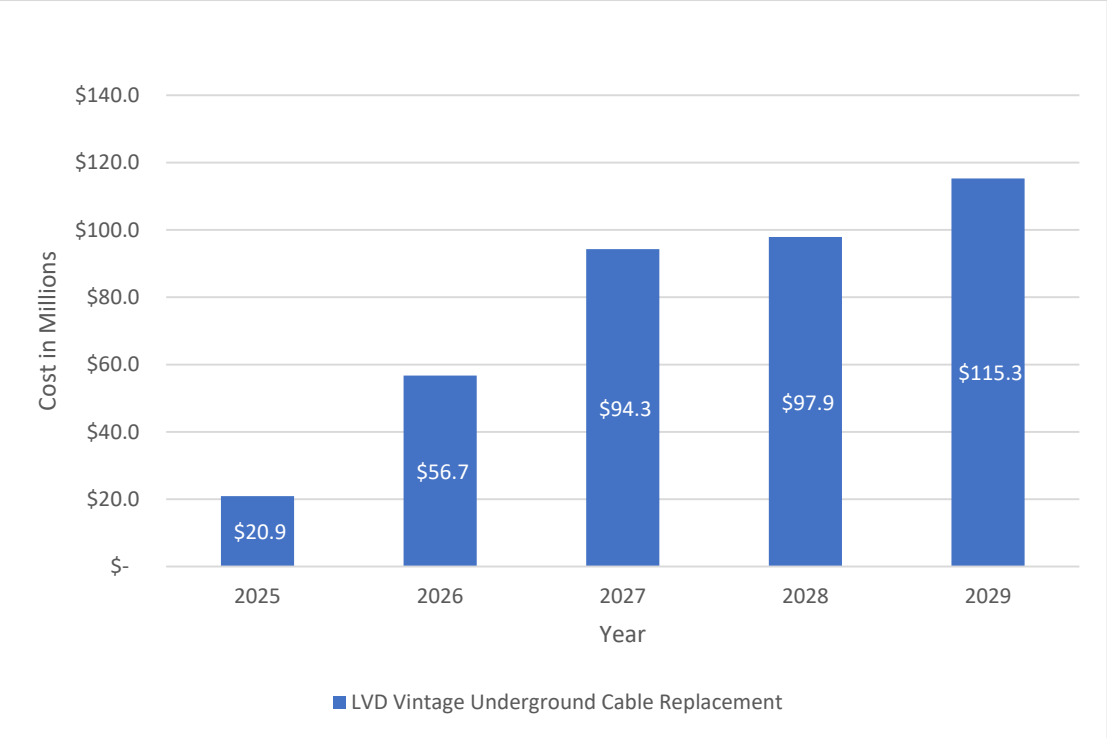
The Company will address all the 15 kV cable installed between the 1960s and 1980s, at a cost of $885 million over 9 years, beginning in 2025.

The program will ramp up each year until reaching a peak in 2031, then ramp back down through 2033 as the final cable replacements are completed. Near the completion of the program, the Company will evaluate the state of the rest of the underground system to determine the appropriate solution for the next highest risk cables.

The 5-year investment plan for LVD Vintage Underground Primary is shown below in Figure 62.

Figure 62

LVD VINTAGE UNDERGROUND PRIMARY 5-YEAR INVESTMENT PLAN



Year	Miles of Vintage Underground Cable Rejuvenated or Replaced
2025	51
2026	136
2027	226
2028	234
2029	276

Resiliency Investments

The increasing frequency of major and extreme interruption events due to severe weather has increased the Company's focus on ways to mitigate major weather events through resiliency investment.

Resiliency is defined as the *ability of the system to withstand a major event—particularly, a large or extreme storm—and the ability of the system to recover from a major event where damage occurs, minimizing the needed restoration and repair time.*

Reliability is defined as the *ability of the system to withstand normal variation and continue serving customers predictably*.

Resiliency and reliability are related.

- While *reliability* focuses on the typical days of the year, when conditions are normal, *resiliency* actions are focused on the much less frequent large or extreme storms. A resilient electric system yields reliable customer service by withstanding these extreme storms.

The following investment categories represent the Company's forward-looking investment in the grid to enable it to better withstand these extreme events, and to facilitate improved restoration times after these types of events occur.

LVD Undergrounding

The radial configuration of the LVD system and the proximity of large parts of the system to trees and other weather impacts necessitates additional investments to harden the LVD system to improve resiliency.

For one component of this, the Company has started to expand its underground system, strategically converting parts of existing overhead circuits to underground.

- Research conducted by peer utilities, most notably WEC Energy Group, has found that **undergrounding improves circuit performance by 90% or more,** as lines are no longer exposed to trees and other weather impacts.
- The Company estimates that **the cost to customers of undergrounding is comparable** to other means of hardening against trees and other weather impacts, such as by installing aerial spacer cable or tree wire.

The Company completed converting approximately 10 miles of overhead lines to underground in 2024 and early 2025, as approved in Electric Rate Case No. U-21389. This work was based on specific selection criteria. Following pilot completion, the Company retained most of its pilot selection criteria, but made adjustments to others, and is now using the following criteria going forward:

- Are single-phase sections of the system
- Have at least one outage in the last 24 months
- Serve between 10 and 200 customers
- Are operated at one of the three standard voltages
- Do not have other project work planned to enhance reliability
- Recent history of significant tree and weather-related outages
- Would have capacity available to account for future load growth

The Company plans to continue using these selection criteria to select undergrounding projects going forward.

Single-phase sections will have a lower conversion cost. Lines with at least one outage in the last 24 months were selected to provide more immediate benefit.

Limiting the customers served by the zone to between 10 and 200 ensures the project provides benefits to more than a few customers, while limiting the impact of any future outage on the underground facilities.

Underground conversion of only the three standard voltages ensures that additional costs are neither initially incurred on the additional equipment to accommodate delta configurations nor the conversion cost to a standard voltage later.

Similarly, selecting zones that are not considered for another reliability project avoids duplication of efforts. Underground conversion is considered an alternative when reliability projects are developed for targeted circuit improvement work.

Lines with recent history of significant tree and weather-related outages were selected to improve customer experience.

Actual costs and lessons learned from the undergrounding pilot has informed how the Company scales up its undergrounding work to ensure scaling the program will be successful.

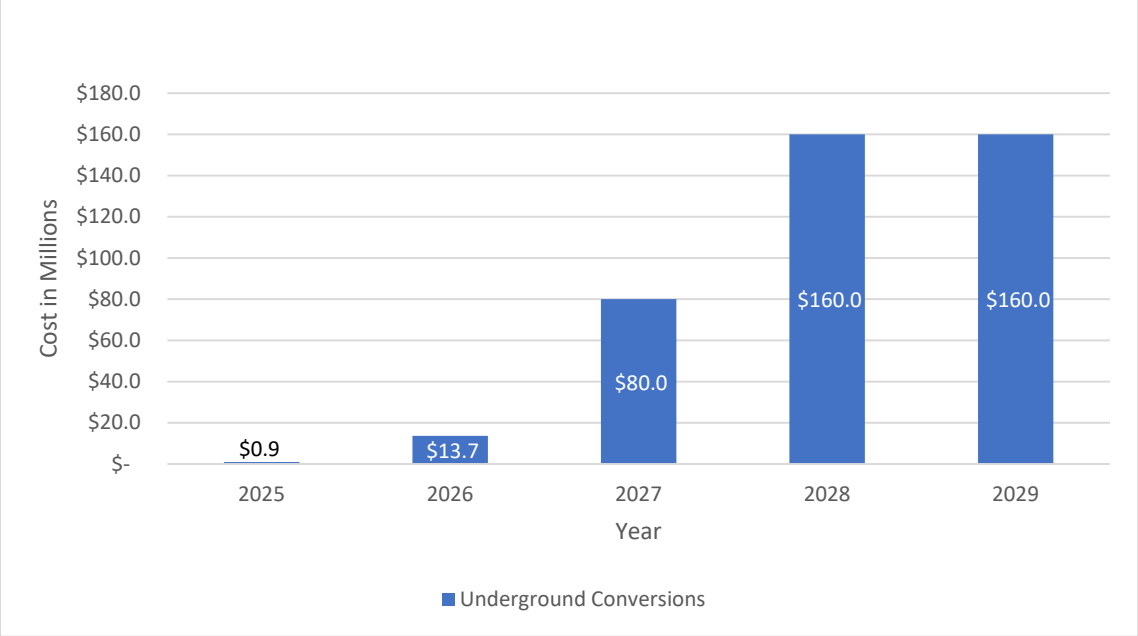
- The Company is planning to ramp up undergrounding work to 400 miles of line annually. Future analyses will take place as the program progresses to determine if the scale of the program should be reduced or increased. Ultimately, approximately 3,200 miles of the LVD system may be evaluated for undergrounding based on the criteria listed above.
- In identifying circuits for undergrounding, the Company is considering whether circuits serve EJ communities, given that these communities are more vulnerable in the event they experience a long outage following a catastrophic storm.

The projected cost for this work is identified below in Figure 63, with the in the projects to begin again in 2026, and full annual capacity of the undergrounding work beginning in 2028. With only 16% of primary lines currently undergrounded, the Company has a much larger exposure to the elements than its regional and Michigan peers, who average 25% of their systems undergrounded.

Expanded, strategic underground conversion of more of the Company's system is imperative to bring the Company's system in line with its peers and thereby improve reliability and resiliency for customers.

Figure 63

UNDERGROUND CONVERSIONS 5-YEAR INVESTMENT PLAN



Year	Underground Conversion Miles
2025	1
2026	34
2027	200
2028	400
2029	400

Fractionalization

On average the Company's LVD circuits are 30 miles with an average of 1,045 customers. Circuits with mileage exceeding the average exposes our customers to a much higher risk of weather-related outages.

Fractionalization, described earlier in the Five Fundamentals Approach, is another approach used by the Company to improve resiliency on the LVD system and involves **segmenting existing LVD circuits into smaller sections with fewer customers.**

- At present, this work takes place in substations, adding new transformer banks and circuit exits so that more circuits with fewer customers can be served from that substation. **This reduces the number of customers affected when there is an outage on a given circuit.**
- Fractionalization also provides more opportunities for load switching if an outage occurs, allowing for improved fault isolation and faster restoration of customers.
- Additionally, fractionalization results in fewer line miles for line workers to patrol and repair, further reducing outage times.

In the near term, the Company is primarily focusing fractionalization on circuits in the top 3% of customer count, and overhead line exposure; circuits in this top 3% serve more than 2,400 customers or have more than 90 miles of overhead lines as shown below in Figure 64, with the 5-year investment plans shown in Figure 65.

Figure 64

CIRCUITS RANKED BY CUSTOMER COUNT

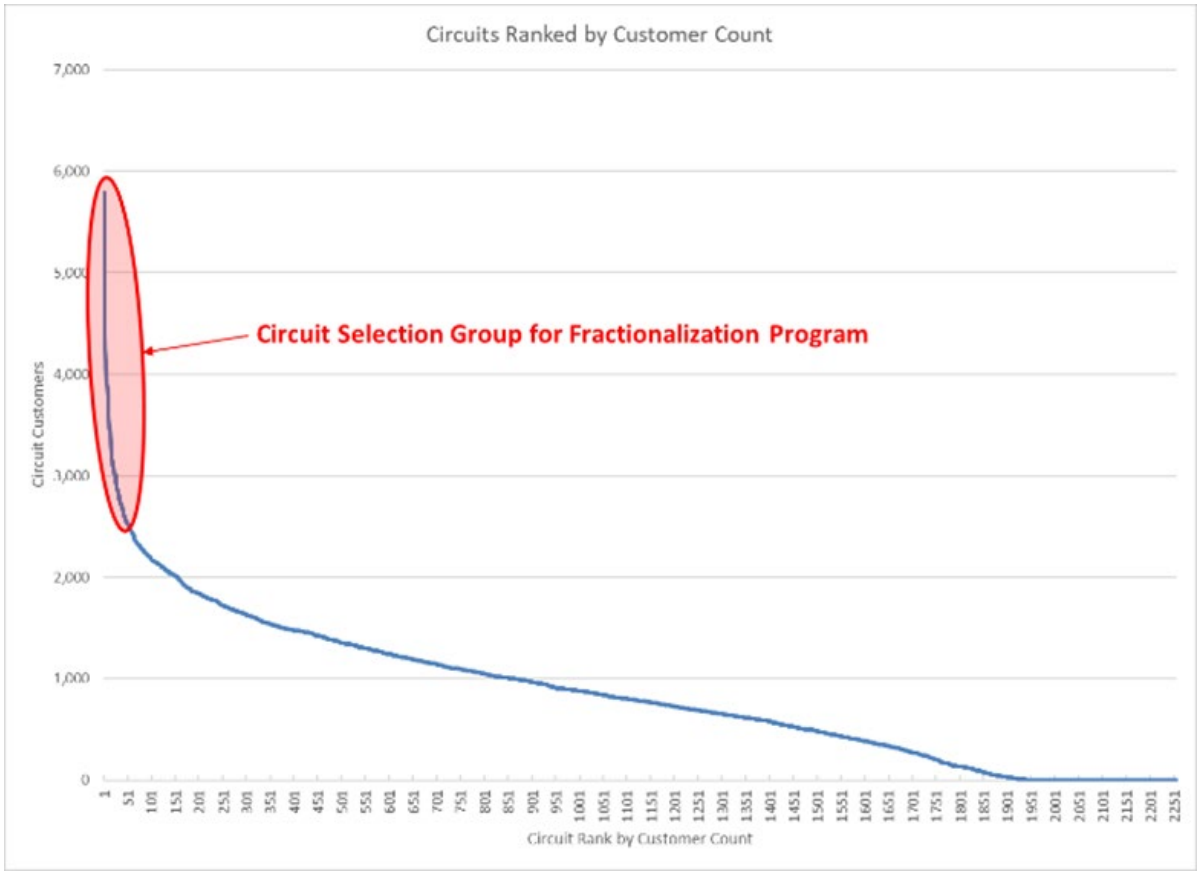
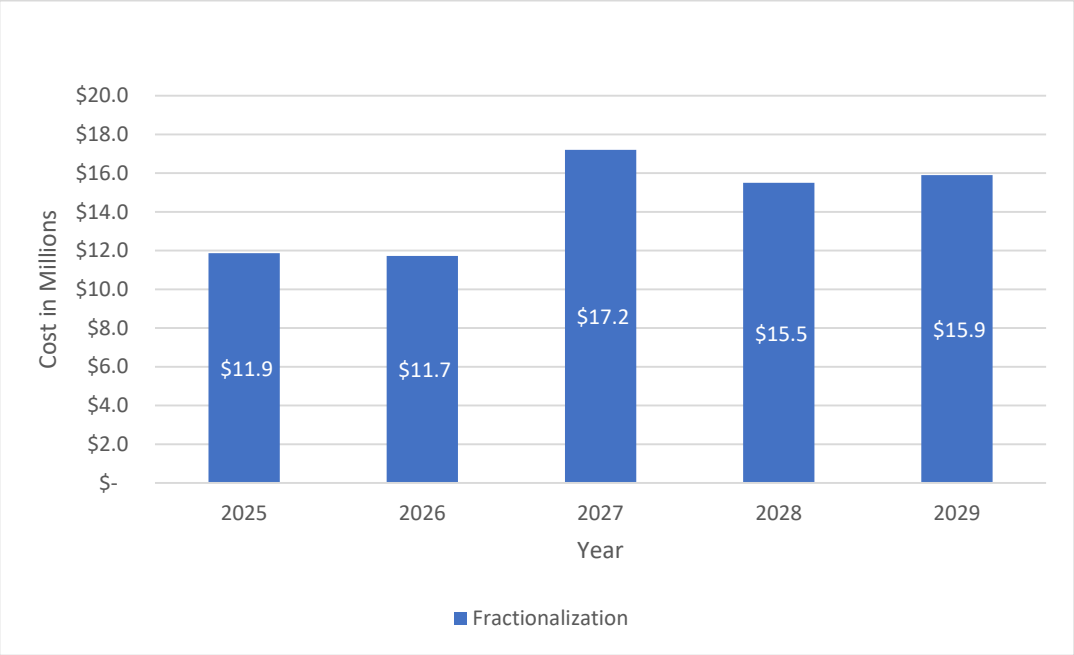


Figure 65

FRACTIONALIZATION 5-YEAR INVESTMENT PLAN



Year	Circuits Fractionalized
2025	6
2026	4
2027	5
2028	5
2029	5

Automatic Transfer Recloser (ATR) Loops

ATR loops have been an integral part of the Company's resiliency plan over the last decade.

Deploying ATR devices on adjacent LVD circuits enables **automatic transfer of customers if an outage occurs. This reduces customer outages and improves system reliability** by isolating a faulted section of a circuit.

- As of March 2025, there are 174 loops in service throughout the state.
- In 2024 alone, there were 138 instances in which an ATR loop operated, avoiding 21.9 million customer outage minutes, and preventing over 77,000 customers from experiencing an outage.
- Over the next five years, the Company plans to deploy between 25-35 additional loops annually to enhance automation on the grid and increase reliability savings.

As the ATR loop deployment matures, the Company is employing new, complex planning techniques to maximize benefits.

Currently, the Company is using "load limited" and "mutually exclusive" loops to enable ATRs, and to get the most out of the distribution system's capacity to avoid costly equipment upgrades, while still achieving significant automation benefit.

Previously, the Company may have ruled out an ATR solution for circuits where peak load conditions would exceed the equipment's thermal or loading ratings.

- Using ADMS, the Company can create real-time alerts that inform system operators when a circuit is approaching its peak load. Loops on these types of circuits are called "load limited."

Similarly, the Company has expanded the ATR loop selection criteria to include circuits fed from the same substation as an existing loop.

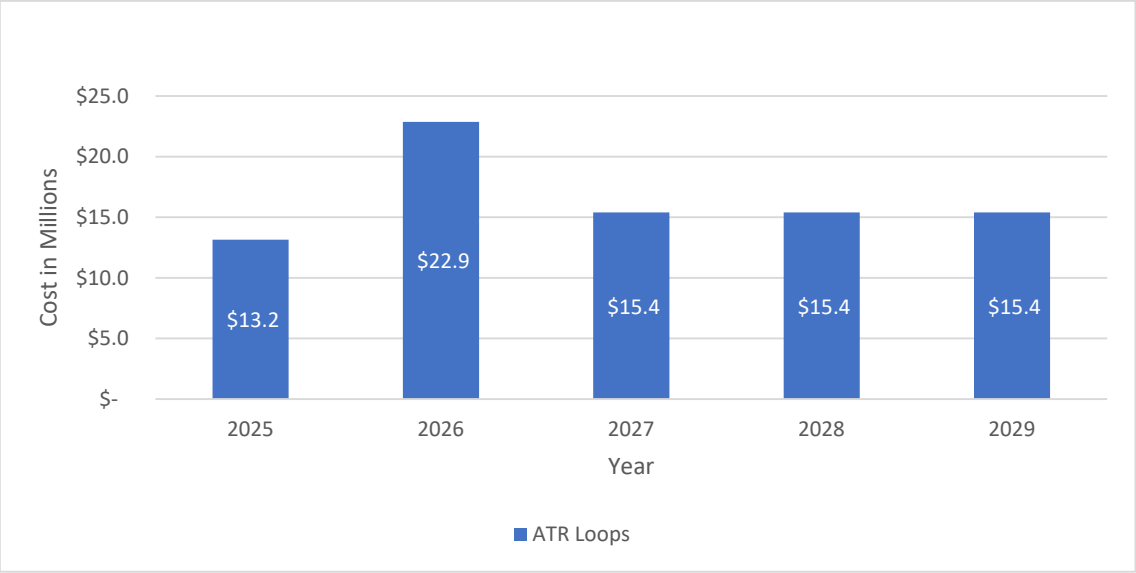
- To avoid overloading a substation transformer, alerts have been set up to notify operators when one of these mutual-substation loops has operated. These alerts trigger established processes for the operator to remotely disable loop scheme capability. Loops on these circuits are called "mutually exclusive."

These "load limited" and "mutually exclusive" loops allow for more circuits to be considered in the selection process, and as a result the Company can increase the achievable benefits from this investment category.

The ATR loops 5-year investment plan is shown below in Figure 66.

Figure 66

ATR LOOPS 5-YEAR INVESTMENT PLAN



Year	ATR Loops Installed Plan
2025	30
2026	44
2027	30
2028	30
2029	30

Other LVD Investment Areas

LVD Transformers

What Transformers Do

Distribution transformers convert voltage levels to enable customers to use standard equipment in their household or business.

- Within the overall category of LVD transformers, *isolators* are a specific type of transformer used to convert one primary voltage to another primary voltage.
- *Regulators* are a special transformer that ensure primary voltage remains in the desired range for reliable end-of line-voltage for customers.

In all, distribution transformers provide safe and reliable service to new and existing customers at an acceptable, reliable voltage. The correct transformer, sized to meet the customer's usage, is key to providing a reliable service experience.

Number of Transformers in Service Territory

There are roughly 600,000 padmount and pole mount transformers units active.

Lifecycle Analysis

The overall average lifespan of a distribution transformer as quoted by transformer manufacturers is approximately 25 years.

However, a typical transformer can exceed the manufacturer's lifespan, depending on different factors. The load and environment have the largest contribution on the health of a transformer and it's common to see transformers exceed 30 or 40 years of life.

The average transformer in the Company's service territory is 47 years old.

Supply Chain Risk

Across the industry, utilities including the Company face risk related to transformer availability.

The strain on raw materials, which began in 2020 because of the COVID pandemic, put a major constraint on transformer production in the United States. Resource scarcity also drove up the cost of transformers. However, the Company has been able to manage this supply chain risk through three strategies:

1. Using longer-term purchase contracts with vendors instead of spot purchases
2. Using a broader pool of vendors (see more below)
3. Planning further ahead for anticipated and forecast demand

High Load Risk

Transformers will be directly impacted by increased electrification of consumer appliances and transit.

The Company is anticipating the need to upgrade transformers more frequently due to the increasing loads with EV chargers, heat pumps, and other home electrification efforts.

In short, as customers begin using more electricity, the Company will have to replace more transformers more frequently to provide service for the new customer load.

Load Growth Risk

Transformers also face risk when customers drastically increase their load without notifying the Company.

Residential transformers are sized to meet traditional residential demand load. However, when customers add load after a transformer is installed without notifying the Company, this can put a major strain on the transformer and other customers whom that transformer serves.

New activities, like indoor growing operations installed in a residential home, create voltage problems for customers as well as overloads on transformers, which can lead to an earlier than expected end of life for the transformer up to and including failure.

The Company is working to diversify its supply chain and enhanced the standards of new transformers to meet the increased customer load of the future. This will help ensure we have enough transformers on hand to support our existing customers as well as meeting any new requests for electric service.

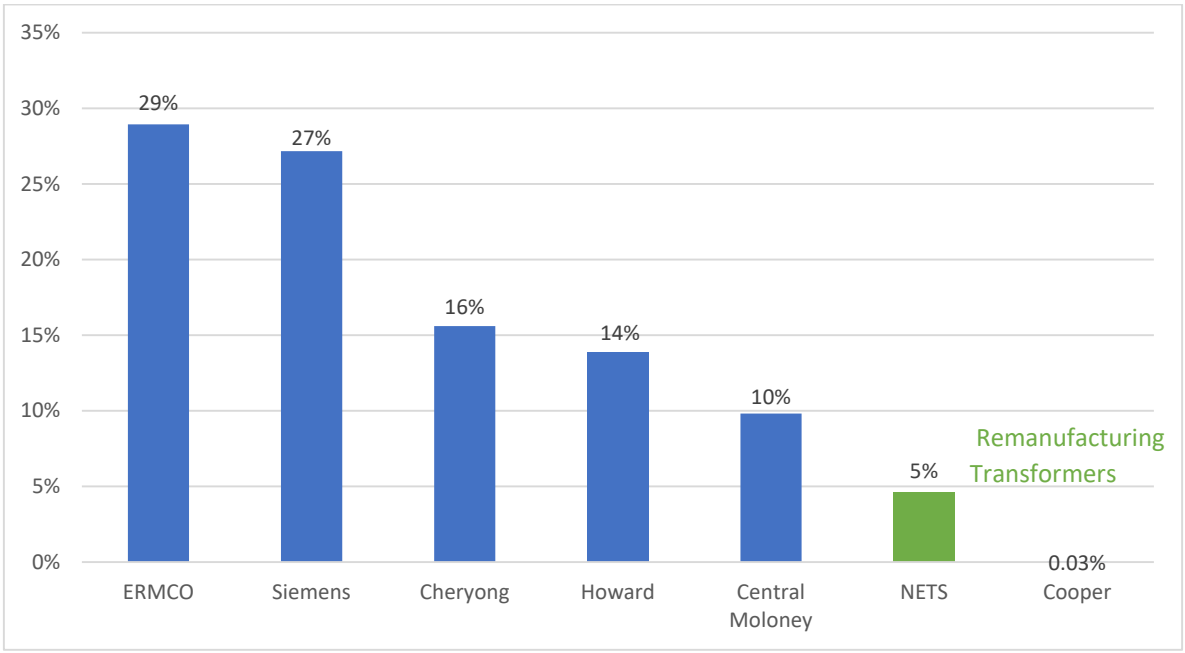
- In addition to exploring new contracts with additional suppliers, shown in Figure 67 below, the Company is also reviewing different styles of transformers that are compatible with its grid, such as *amorphous core* style units and dry type transformers.

  NOTE: Amorphous core transformers differ from traditional silicon steel transformer cores in that amorphous cores are made up of ribbons of metal that are *not* grain-oriented versus a rolled sheet of grain-oriented steel that is used in a traditional silicon steel core. **This difference in construction results in lower voltage losses in the voltage transformation process.**

The Company is also updating its standards to account for the anticipated addition of EV chargers on new builds and remodels. Taken together, these strategies will ensure the Company is able to prepare for the future while continuing to provide reliable service.

Figure 67

PERCENTAGE OF TRANSFORMERS ORDERED FOR 2025 BY SUPPLIER



The Company will procure enough transformers to serve new load requests and restore power in the event of unplanned outages on the system.

These estimates account for the drastic increase in transformer costs we have realized in 2023 as well as additional need for transformers to be available for EV adoption over the next 5 years.

The 5-year Investment Plan for LVD Transformers

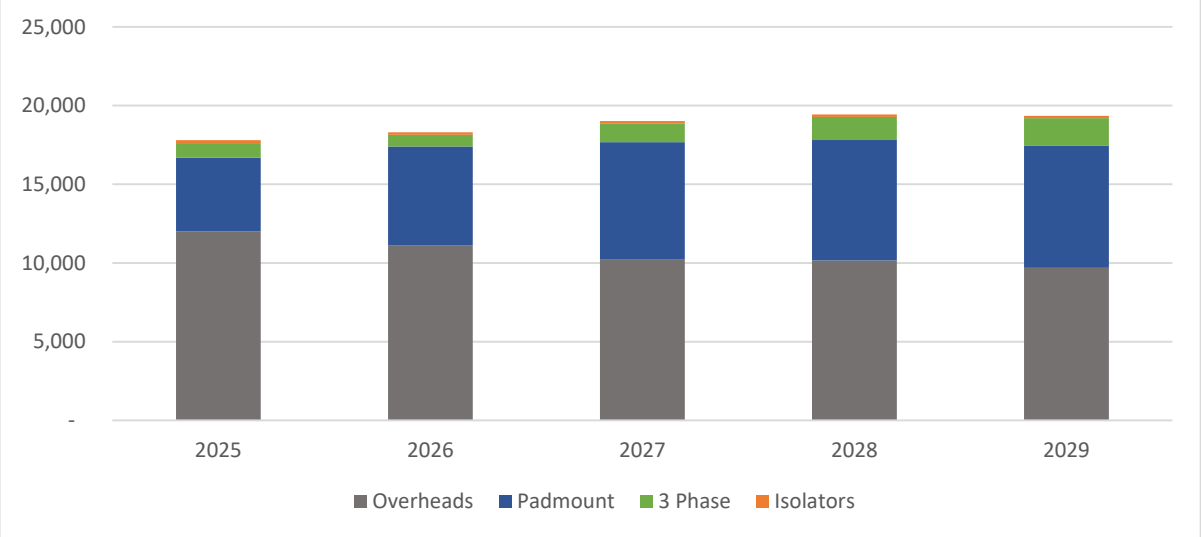
As a result of delays stemming from the COVID-19 pandemic, the Company received increased deliveries of overhead transformers in 2023 and 2024 to restock inventories of those units.

In 2025, we expect purchase volumes to return to pre-pandemic levels with some additional demand factored in. From then on, we expect that purchases of overhead transformers will remain generally level.

The Company expects a significant increase in purchases of padmount transformers tied to increased undergrounding work and the need to support customers adopting electric vehicles. This is reflected in the 5-year investment plan and unit forecast in Figure 68 below.

Figure 68

PLANNED TRANSFORMERS TO BE PURCHASED



TYPE	*2025*	*2026*	*2027*	*2028*	*2029*
3-PHASE	*927*	*741*	*1,189*	*1,464*	*1,758*
PADMOUNT	*4,690*	*6,267*	*7,469*	*7,658*	*7,746*
OVERHEADS	*12,000*	*11,135*	*10,207*	*10,157*	*9,696*
ISOLATORS	*183*	*163*	*154*	*154*	*147*

Meters

What Meters Do

Electric meters, meter sockets, and metering transformers are needed to **provide safe and reliable measurement of electricity usage** for customers.

LVD Metering investments support the Company's obligation to serve, and provide the means to measure customer electricity usage, provide the data required to generate customer bills, and provide usage data to customers safely and accurately.

Furthermore, smart meters provide customers with data to enable them to take greater control of their energy consumption.

Metering is an essential part of connecting new customers through its overall New Business Program, as well as replacing failed equipment. Additionally, *advanced metering* is an essential component in many of the Company's current and future demand response and renewable programs.

- *Advanced Metering* is defined as *an integrated system of smart meters, data management systems, and communication networks that enable two-way communication between the utilities and the customers.*

Number of Meters in Service Territory

There are roughly 1.92 million electric meters currently installed, of which 1.90 million are smart meters. The remainder are a combination of legacy (non-communicating) meters, and commercial or industrial meters.

Lifecycle Analysis

The overall average lifespan of an electric meter is 20 years. However, with the deployment of cellular smart meters, meter lifespan can be affected by the availability of the communications network, as meters contain communications modules that are network-specific, such as 3G LTE, 4G LTE and 4G CATM1.

3G Meters

From 2021-2023 the Company worked to exchange and upgrade 620,000 3G meters to 4G CatM1 technology, which is 5G forward compatible.

The goal of this project was to have all 3G meters off the system when Verizon retired its 3G LTE network. Beginning in 2023, Verizon retired the 3G LTE network making the remaining 188,000 3G meters obsolete. The Company has since completed the remaining exchanges. As of November 2, 2024, there are only 15 3G meters remaining, only 1 of which has a customer attached.

4G Long-Term Evolution ("LTE") and 4G CatM1 Meters

As of June 2023, there are 1.18 million 4G LTE meters installed on the Company system, and 700,000 4G CatM1 meters.

The Company's 4G LTE communications network provider, Verizon, has not provided a definitive date for the retirement of the 4G LTE network, but they expect to maintain the network into the mid- to late-2030s.

With that in mind, the Company is evaluating its existing metering technology, vendors, and software, including technology to support future electric and gas system integrations (e.g., Distributed Energy Management Systems ("DERMS") and edge-DERMS, among other systems).

By year-end 2025, the Company expects to have defined a strategy for eventually replacing 4G meters that accounts for Verizon's timeline.

The Company's strategy will be heavily informed by the overall investment required. Once a strategy is set, the Company will maintain the existing technology and the existing population of 4G LTE and 4G CatM1 meters for the next three to four years before transitioning to 5G meters.

The Company is also considering advanced metering infrastructure ("AMI") software that can be integrated with other grid operations software, including DERMS and edge-DERMS.

The choice between AMI technologies will not impact AMI purchasing decisions in 2025, but the choices the Company is evaluating may impact the Company's future meter purchases. Until a software decision is made, the Company cannot say what type of meter it may decide to purchase in the future.

In the meantime, the Company is currently purchasing 4G CatM1 meters, which are 5G forward compatible and therefore would not need to be replaced to use the 5G network.

With the current AMI technology in use, gas meter reads for combination gas-electric customers are transmitted to the collection system via the electric meter. Due to this interdependency, the Company must look at any future updates or changes to the AMI system holistically.

The Company identified scenarios in 2023, and in 2024 it began analyzing each scenario. The scenarios include maintaining existing technology (status quo), using a single meter vendor, and using multiple meter vendors. To test the scenarios, the Company is performing a SWOT (Strength, Weakness, Opportunity, Threat) analysis, evaluating each scenario's advantages and disadvantages.

The Company is also looking at similar functionality in use today, including automated reading, remote turn-on and turn-off, and other new functionalities being offered such as grid-edge computing.

The Company's business case for future AMI technology, when developed, will prioritize replacing technology that is obsolete.

Metro System

What the Metro System Does

The Company's Metro system provides underground electric distribution service in the downtown areas of Battle Creek, Flint, Grand Rapids, Jackson, Kalamazoo, and Saginaw.

Metro distribution assets consist of conductors contained in duct banks encased in concrete, with transformers and switching points placed below ground in larger working spaces called vaults and smaller working spaces called manholes.

Some of the cables are made of oil-and-paper-insulated, lead-sheathed conductor that is no longer manufactured.

The Metro system also includes padmounted switchgear, which consists of above ground switches and fuses in steel enclosures and padmounted transformers.

The Metro system promotes safety by ensuring the public does not encounter energized equipment. It also promotes aesthetics, and ensures it is less disruptive to the community and businesses to conduct repairs.

Number of Assets in Service Territory

As of 2024, Metro infrastructure includes 156 total vaults and 1,429 total manholes. Vaults and manholes are connected to each other through duct banks.

Lifecycle Analysis

The expected lifecycle of Metro assets is between 45 and 62 years, with civil assets lasting longer than electrical.

Much of the Company's Metro infrastructure was first installed from 1910 through the 1950s, and is still in service today.

The average lifecycles for Metro assets along with the average ages of these assets that were retired between 2017 and 2021, are shown in Figure 69 below.

Note that many assets are beyond their expected useful life, with some assets functioning for more than double the expected life.

FIGURE 69

METRO LIFECYCLE DATA

Device	Metro Conduit/Civil Infrastructure	Metro Conductor and Electrical Assets	Metro Transformers	Metro Services
Expected lifecycle	60 years	62 years	47 years	45 years
Average retirement age, 2017-2021	88 years	61 years	N/A	46 years
Maximum retirement age, 2017-2021	121 years	101 years	N/A	69 years

Public and Employee Safety Risks

Vaults and Metro system represent a minor public safety risk due to assets being located underground in public rights of way (typically under the sidewalk), making accidental public contact exceedingly rare.

Metro System Asset Health and Risks

The Metro system consists of two primary components:

- Civil infrastructure consisting of vaults, manholes, and duct banks.
- Electrical infrastructure consisting of conductor, transformers, and controlling devices.

Each infrastructure type has unique risks detailed below.

Civil Infrastructure Risks: The biggest risk to civil infrastructure is the age and physical size of vaults, manholes, and duct banks. Today's modern electrical cables, controlling devices and transformers require more physical space to safely maintain and operate this electrical equipment.

Electrical Infrastructure Risks: The biggest risk to the electrical infrastructure in the Metro system is driven by the live primary exposed parts in vaults and padmount switchgear, which presents a safety risk to the Company's workforce. Due to the enclosed space of the vaults, employees must take precautions to maintain working space clearances when working around these live metal parts.

Lead Risk: Another risk to the electrical infrastructure in the Metro system is driven using Paper Insulated, Lead Covered ("PILC") and Varnished Cambric, Lead Covered ("VCLC") primary cables. As noted above, this type of cable is obsolete and no longer manufactured; the existing lead conductor in the Metro system is more than 50 years old. Because of this obsolescence, if lead cable fails it cannot be replaced, and instead must be spliced back together, which is a laborious process. As of 2024 the Company has more than 240,000 feet, or approximately 11% of the overall Metro system, of primary lead-covered cables of various sizes in service interconnecting the vault system to the metro substations.

Modeling & Prioritizing Risk

Metro planning and design engineers use a model to assess multiple components of each vault which produce a vault health score ranging from 0 to 180.

These components are assessed first to determine whether the risk is present, then given a multiplier based on the severity of the risk.

- Vaults with some risks present will receive a weighted score with the highest weighting given to wall, roof, and entrance condition as well as electrical connections.
- Based on the severity, a vault will be labeled as Yellow or Red, which will then multiply the score by 1 or 2, respectively.
- Vaults with no risk for a certain component are assessed as Green with a multiplier of 0.

Figure 70 below shows how the evaluation criteria is applied to a hypothetical vault.

FIGURE 70
METRO RISK ASSESSMENT MODEL

		Weighting:	10	10	10	2	4	3	1	10	7	2	5	5	4	3	4	3	3	2	2	180
			Civil							Electrical												
Asset Name	Reviewer	Review Date	Roof condition	Wall condition	Entrance condition	Entrance Location	Ventilation	Cable Rack Condition	Depth of water, as found	Electrical Connections live/dead	Working space	Switch type	Switch Condition	Transformer condition	Equipment sized for Fault Current	Grounding/Bonding Conditions	Lead cable	Splice Condition	Fireproofing/Arc Tape	Primary configuration (delta or grounded)	Alternate primary feed	Total Score
Sample Vault			R	R	R	G	G	Y	G	R	Y	Y	Y	Y	Y	Y	Y	G	R	G	G	119

Based on an assessment of these characteristics, a vault with a score above 70 qualifies for a red rating, which indicates major deterioration. A score between 51 and 70 is given an orange rating, showing moderate deterioration.

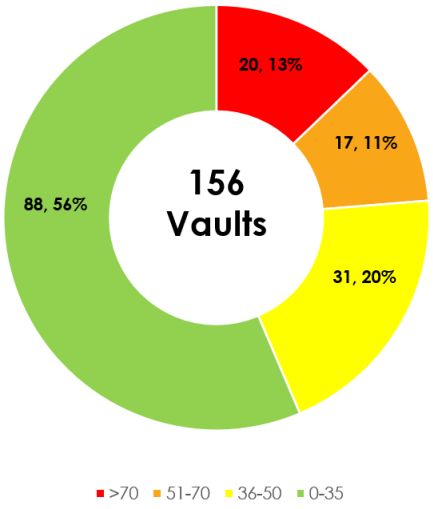
As of 2024, the most recent Company assessment of its vault health is shown in Figure 71.

This indicates that 24% of the vaults inspected show major or moderate deterioration, which the Company will prioritize.

In 2023, 27% of vaults had major or moderate deterioration; this drop is attributed to the reliability work executed over the past year. It is also important to note a drop in high-risk 'red' vaults from 28 vaults in 2023 to 20 today.

FIGURE 71

SUMMARY OF METRO HEALTH VAULT ASSESSMENT RESULTS



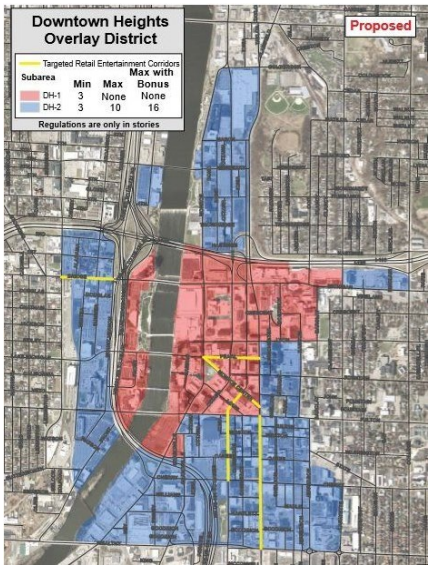
Metro System Growth & Expansion

In addition to the asset health risks on the existing Metro System, the Company is responding to major transformative plans publicly shared by municipalities that will spur economic growth, address housing shortages, and enhance urban vitality.

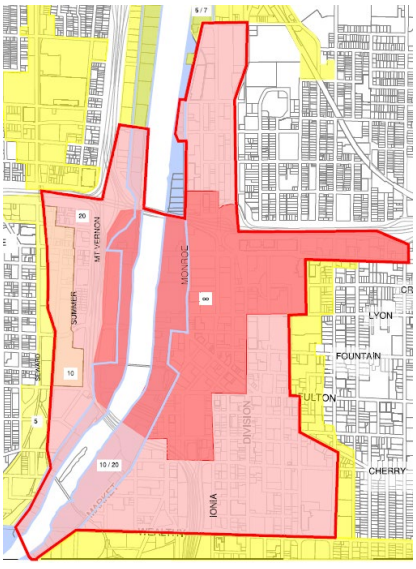
Grand Rapids is the leader in this effort. In 2023, the city approved zoning changes to allow for taller buildings in the downtown area, and expanded this area outside to the west, south and north of the traditional downtown area. These zoning changes built on earlier ones from 2017.

Figure 72

Grand Rapids Zoning Changes



2017 Height Overlay



2023 Height Overlay

In these maps, the red areas allow for unlimited building heights. In the 2017 map, the blue areas had a 10-story limit on building height. In the 2023 map, the pink areas now have a maximum building height of 20 stories.

Since the approval of the new height overlay district in Grand Rapids, developers have approached the Company with plans for new civic assets, including the planned Acrisure Amphitheater and Amway Soccer Stadium.

Each civic asset project includes additional housing development projects to address housing needs in Grand Rapids. The Acrisure Amphitheater and Amway Soccer Stadium site developers have proposed a 21-story mixed use building with 475 residential apartments near the amphitheater and a 18-story mixed use building to include 260 residential apartments.

These proposals include a Transformational Brownfield Plan approved by the Michigan Strategic Fund.

Additionally, Fulmar Property Holdings has proposed a major project with three high rise towers, including:

- 21-story, 420,000 sq ft office tower
- 43-story, 595-unit apartment tower
- 27-story, mixed use hotel and condominium tower

FIGURE 73

ILLUSTRATION OF NEW DOWNTOWN GRAND RAPIDS DEVELOPMENT



Similar developments are taking place in Kalamazoo, including a $300 million event center, along with other civic improvements including flood control and relocation of Arcadia Creek, and conversion of the city's one-way streets to two-way multimodal traffic flows. Existing Metro infrastructure under these one-way streets (Michigan Avenue and Kalamazoo Avenue) is at end of life.

The Company is taking the opportunity to rebuild the system as a 'coordination of utilities' project in 2026 and beyond.

FIGURE 74

ILLUSTRATION OF KALAMAZOO EVENT CENTER DEVELOPMENT



Additionally, the City of Saginaw, Saginaw Future, and other stakeholders have announced development of the Saginaw Medical Diamond Project, bringing medical education facilities, mixed-use commercial property, residential property, and a new waterfront park on the south side of Downtown Saginaw. The Company has committed to doing a coordination of utilities project with this development, converting existing overhead systems into a new Metro infrastructure.

FIGURE 75

ILLUSTRATION OF SAGINAW MEDICAL DIAMOND PROJECT



Investments to Address Metro Asset Health & Expansion

The Company's ideal end state would be to rehabilitate and deadfront all the vaults with moderate or major deterioration.

- The Company's strategy for civil infrastructure is to rehabilitate or rebuild at-risk vaults, manholes, and duct banks in a way that, whenever possible, aligns with projects undertaken by municipal governments, commonly referred to as 'One Dig' or 'coordination of utilities' projects.
- The preference for coordination with local authorities means that the Company cannot unilaterally decide to rehabilitate all 'red' or 'orange' vaults over a defined near-term period.

In some instances, the Company may still need to act unilaterally to execute Metro projects. Examples of this kind of situation happened recently in Jackson, where the Company rebuilt its civil infrastructure in Cortland Street between Martin Luther King Street and Mechanic Street. The Company was able to consolidate to existing vaults into one new structure. This work was done solely by the Company without coordination of other utilities or the municipality.

To ensure optimal performance and operation of the Metro system, the Company carries out the following actions to properly protect and maintain its assets:

Deadfronting and Vault Rehabilitation

The Company performs Metro vault rehabilitations and reliability deadfront projects to remediate risks to identified vaults.

The *Deadfronting* process is used to reduce employee exposure to live equipment and *involves replacing exposed primary termination points and bushings with covered or insulated components to reduce the risk of workers contacting energized components*.

Rehabilitation projects will typically replace the vault structure and its electrical components in its entirety.

The pictures in Figure 76 show the difference between exposed and deadfronted components on rehabilitation project, with a new vault installed to replace the existing structure.

FIGURE 76

VAULT BEFORE AND AFTER REHABILITATION PROJECT



The pictures in Figure 77 show a vault reliability project that rebuilt the electrical infrastructure and performed minor concrete repairs.

FIGURE 77

VAULT BEFORE AND AFTER RELIABILITY PROJECT



Replace Obsolete Electrical Assets

To remediate risks posed by obsolete lead cable, the Company has an initiative to modernize primary cables, allowing them to be more modular so additional cable can be added later if needed.

- Modernizing primary cable also improves capacity and resiliency and creates more capability to accommodate grid modernization components.
- Replacing PILC cable reduces environmental impacts during operations such as dewatering manholes or vaults and reduces occupational hazards when working on lead cable joints and splices.
- PILC cables are no longer manufactured, with replacement cable, joints, and splice materials becoming scarcer.

Metro Inspection and System Maintenance

The Company is reducing reliability and safety risks through its metro inspection and maintenance programs based on recommendations by the *IEEE, NFPA (70B)* and industry best practices.

The Company is proposing the following schedule, shown below in Figure 78, based on good engineering practice to help identify and correct problems before they result in outages.

FIGURE 78

METRO INSPECTION AND MAINTENANCE SCHEDULE

Inspection Task	Cadence	Components Checklist	Annual Cost
Vault Inspections	4 Years	Visual Inspection of vault structure, transformers, switches, cables and other components	$ 650k
Manhole Inspections	4 Years	Visual Inspection of manhole structure, cables, splices, and other components	$ 1,100k
'Hi Rise' Vault Inspections	Annually	Visual Inspection of the room/structure, transformers, switches, cables, and other components	$ 125k
Infrared Thermography Inspections	As Needed	Inspection of electrical components. Can be performed with visual inspections	$ 125k
Total	**$ 2,000k**		

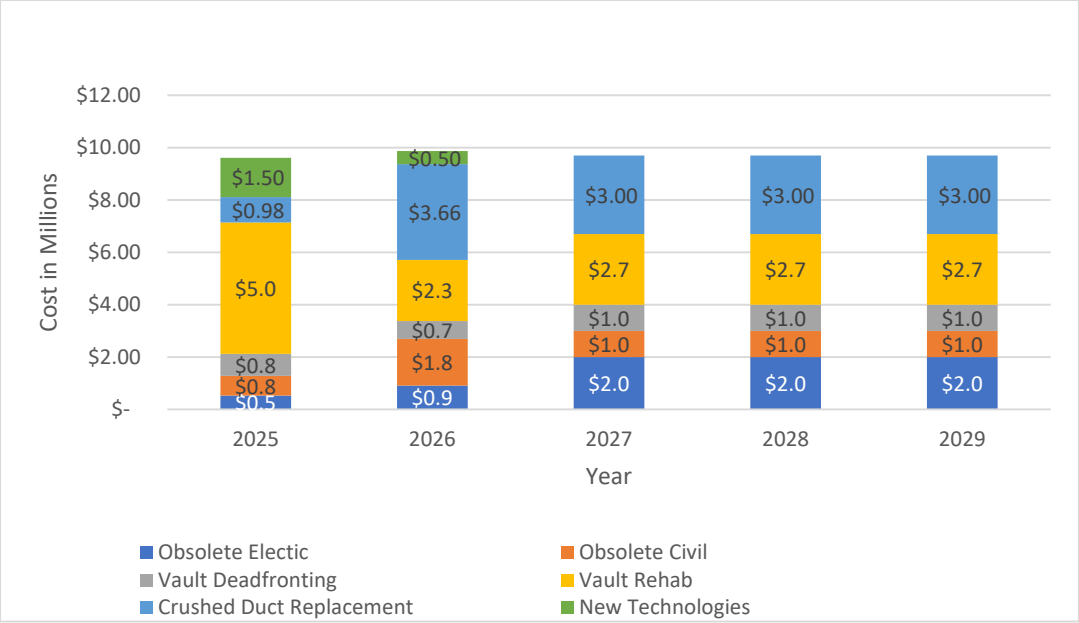
5-Year Capital Investment Plan

The Company will invest in its vaults and primary cable replacement in coordination with local governments to limit interruption of business and commerce in the municipality.

- This plan will enable the Company to complete approximately four vault rehabs, deadfront two vaults, and replace obsolete electric and civils assets on 4 or more vaults per year.
- The 5-year investment plan for the Metro system (shown below) will address workforce safety, reliability, and operational constraints.

Figure 79

METRO RELIABILITY CAPITAL INVESTMENT PLAN



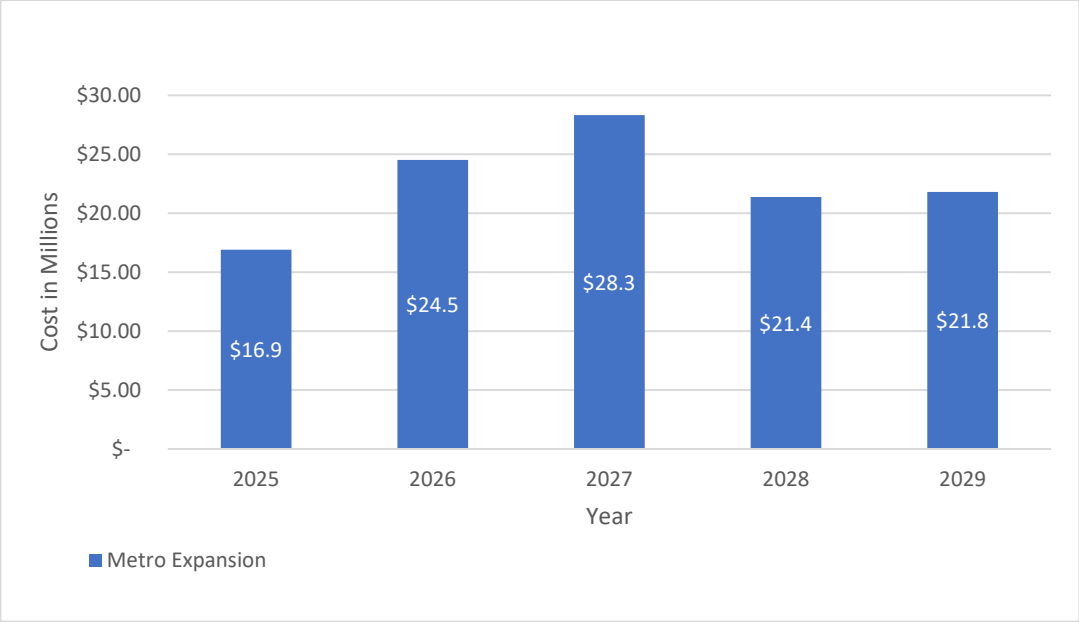
Year	Electric Projects	Civil Projects	Vault Deadfronting	Vault Rehabilitation	Crushed Duct Replacement
2025	1	1	2	6	1
2026	3	2	2	3	1
2027	4	2	2	4	1
2028	3	1	2	4	1
2029	3	1	2	4	1

The Company will invest in new business by expanding its system as appropriate.

The Company will also increase its relocation program to do 'coordination of utilities' with our municipal and internal partners.

Figure 80

METRO EXPANSION CAPITAL INVESTMENT PLAN



Year	New Business Primary Service	New Business Secondary Service	External Coordination of Utilities	Internal Coordination of Utilities
2025	10	20	25	5
2026	8	20	25	10
2027	5	15	20	10
2028	5	15	10	5
2029	5	15	10	5

Forestry Line Clearing Program

Trees are one of the greatest causes of interruptions to electric service to customers on the LVD system, contributing 43.4% of all-weather outages and 37.9% of all non-MED outages[10].

The Forestry *Line Clearing Program* manages vegetation (trees, bushes, vines, etc.) along its primary voltage systems and its secondary voltage systems, including service conductors.

[10] Percent of customers interrupted by unplanned outages in 2024 with cause code of Trees or Trees - Outside ROW.

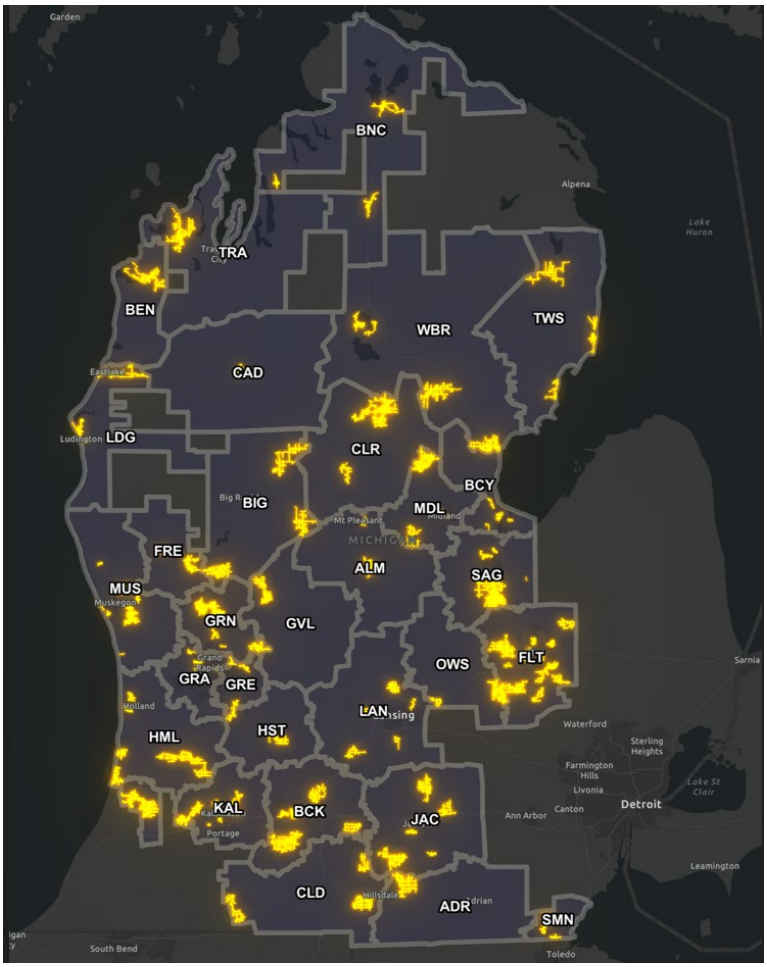
Overview of the Line Clearing Program

The Company clears vegetation within a 30-foot-wide right-of-way ("ROW") for primary voltages to attain a minimum of 10 feet of separation between conductors and vegetation at the time of clearing. This is to maintain accessibility along the ROW for maintenance and repair of the line.

- The largest subprogram within the *Line Clearing Program* targets **full circuit clearing,** where advanced analytics identify work locations throughout the service territory on a full-circuit level.
- This portion of work, encompassing several thousand miles of LVD primary wires, is shown in the 2024 workplan snapshot in Figure 81 below, in which the geographic locations of circuits to be cleared are highlighted in yellow.

Figure 81

2024 LVD FULL CIRCUIT CLEARING WORKPLAN



The Company's *Line Clearing Program* also provides benefits that are not easily quantified, such as **improved habitat for many plants and animals (including threatened and endangered species) and decreased risk of wildfires from tree contacts with conductors.**

The Company has been continuously maintaining a four-year clearing cycle for its HVD system. For its LVD system, the Company has been working for several years towards attaining a seven-year effective clearing cycle, but has not yet attained this cycle.

The seven-year effective cycle describes a strategy of clearing one-seventh of the LVD system miles per year with different targeted cycle lengths of clearing for the three major primary voltages on the LVD system.

Upon achieving the seven-year effective cycle:

- 14.4/24.9 kV circuits would be cleared on average between four to six years;
- 7.2/12.47 kV circuits would be cleared on average between six to eight years; and
- 4.8/8.32 kV circuits would be cleared on average between eight to ten years.

Clearing timeframe in these ranges would be dependent on the circuits' historical performance, reliability predictions, and safety considerations.

Vision for the Line Clearing Program

The Company is proposing to maintain a four-year clearing cycle for its HVD system.

For its LVD system, the Company is proposing a ramp-up to a five-year clearing cycle, while performing more aggressive line clearing on targeted three phase primary lines.

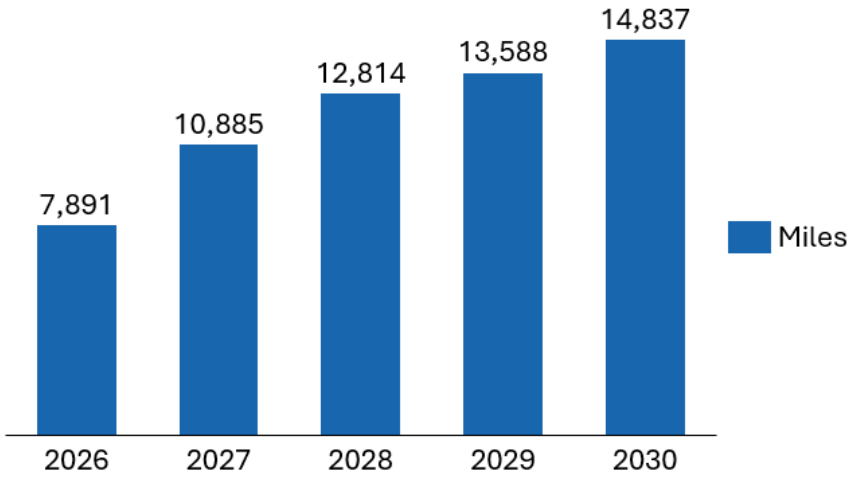
The five-year cycle strategy will involve clearing one-fifth of the Company's LVD line miles annually in steady-state cycle maintenance, while maintaining the standard that all LVD circuits have been fully cleared within a five-year period.

The Company finds that this strategy aligns with other utilities, and it has carefully evaluated the projected costs and benefits of a shorter line clearing cycle for its LVD circuits. It has determined that a five-year line clearing cycle is the right approach to significantly improve electric reliability while responsibly managing customer bill impacts.

The number of LVD miles to be cleared annually over the ramp-up period to achieve the Company's vision are displayed in Figure 82 below.

Figure 82

LVD FULL CIRCUIT CLEARING MILES



In addition, the Company will conduct more aggressive line clearing on targeted three phase primary lines through the practice of canopy removal, which is the removal of all branches above primary wires. This practice is in addition to current line clearing specifications.

- The Company's specification for LVD primary has allowed some canopy to remain (i.e., healthy, non-weak-wooded tree species canopy is cleared to 10-15' from the conductors, and certain weak-wooded tree species canopy clearance is increased to 20' from the conductors).
- The Company performed a small canopy removal study on approximately 42 miles of three phase primary in 2022.

Figures 83 and 84 show examples of canopy removal on an urban and rural section of circuit respectively, pre- and post-clearing in 2022.

Figure 83

CANOPY REMOVAL ON AN URBAN SECTION OF CIRCUIT, 2022



Figure 84

CANOPY REMOVAL ON A RURAL SECTION OF CIRCUIT, 2022



The Company is proposing canopy removal on 10%, or roughly 5,500 miles, of overhead primary, targeting three phase portions of circuits. This includes targeting three phase lines that:

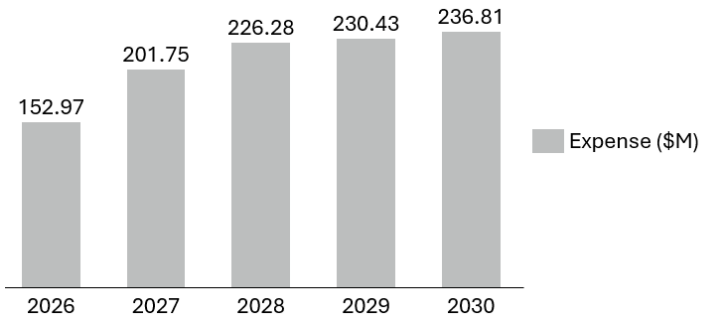
- Have the highest consequence of failure due to serving the most downstream and/or critical customers.
- Enable manual and automatic switching capabilities, reducing the impact of outages that may occur regardless of cause.
- Will inherently include first zones, some second zones, and may extend past the second zone depending on the zone attributes, like customers served downstream, and/or if the conductor is within the path of substation-to-substation connection to enable switching opportunities.

Enhancing the Company's Line Clearing Program by reducing the cycle will improve reliability and public safety. Reducing the amount of time that passes between clearings results in a smaller amount of growth, and therefore less biomass removed at the time of clearing. This results in a predictable result for customers on what their trees will look like after line clearing.

The projected LVD expenses over the ramp-up period to achieve the Company's vision are displayed in Figure 85 below.

Figure 85

LVD VISION PROJECTED EXPENSES



Reliability Benefits of the Line Clearing Program

- The Company's vision will result in clearing an increased number of miles each year to attain the reduced cycle. Line clearing reduces the risk of tree-conductor interference, which can cause customer outages. The prevention of outage incidents results in a better customer experience through reduced tree-caused SAIDI and SAIFI. For circuits cleared entirely in 2022, tree-caused primary outages including MED decreased 60% the year following clearing.
- For circuits cleared entirely in 2022, tree-caused primary outages excluding MED decreased 63% the year following clearing.

Previous analysis indicated, following completion of line clearing, the average LVD circuit reliability improves by:

- Approximately 300 fewer customers experiencing more than 3 outages in the year after tree clearing.
- Approximately 125 fewer customers experiencing outages lasting longer than 24 hours in the year after tree clearing.
- Approximately 225 fewer customer outages during catastrophic storm events within the year after tree clearing.

Figure 86 shows the projected tree-caused primary outage incidents including MED over the ramp-up period to achieve the Company's vision.

Figure 86

2026-2030 PROJECTED TREE-CAUSED PRIMARY OUTAGE INCIDENTS INCLUDING MEDS

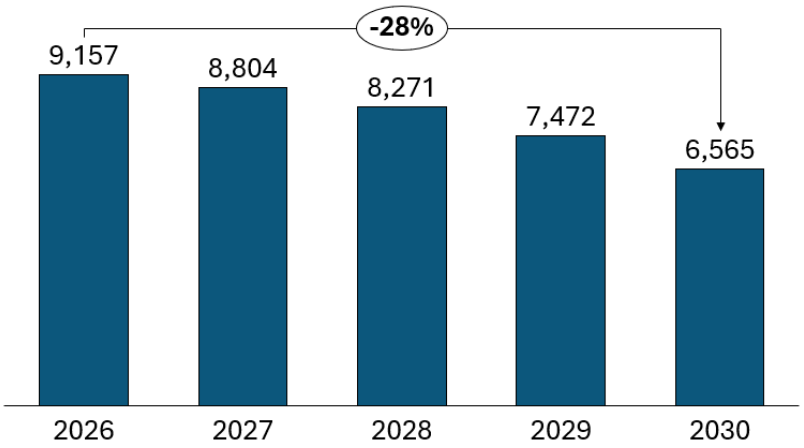
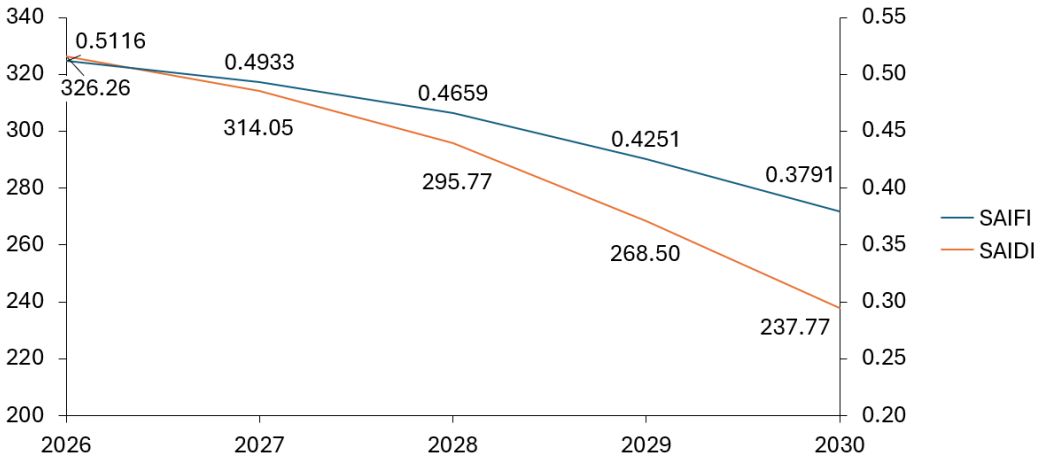


Figure 87 shows the tree-caused outage contribution to SAIFI and SAIDI over the ramp-up period to achieve the Company's vision, driven by a 28% projected primary outage incident reduction from 2026 through 2030.

Figure 87

2026-2030 PROJECTED TREE-CAUSED PRIMARY SAIFI AND SAIDI INCLUDING MED



Forestry Technology Enhancements

The Company continues to perform an in-house review of the line clearing process with the Company's Operations Performance group and Transformation departments to determine what opportunities exist to improve data analytics and performance.

- The Company recently identified an opportunity to modernize its forestry model by harnessing more sophisticated predictive and prescriptive analytics in Machine Learning and satellite imagery analysis to influence and guide its LVD full circuit clearing subprogram.
- This model is built into a web-based tool, called Forestry *Workplan Intelligence & Strategy Engine* ("WISE"), to allow for a consistent, stable, and sustainable methodology to optimize the yearly LVD full circuit clearing workplan, and to capture the most reliability and safety benefit for annual spend.
- Among the most impactful advancements in model maturity are integrating new data such as historical weather data, detailed circuit attributes, tree canopy cover data derived from *National Agriculture Imagery Program* ("NAIP") satellite imagery, and pole attributes.

These, coupled with increased analytic capabilities, **provide a more robust predictive outage model to inform the annual LVD full circuit clearing workplan,** thus allowing the Company to target its line clearing work where it will be the most impactful.

After careful consideration, the Company decided on an internal approach to technology-based enhancement of the work selection process through the development of the Forestry WISE tool.

An internal build of a digital product helps to ensure the tool is flexible in the event of change; for example, the tool currently analyzes and chooses work on a circuit-level, but the Company is pursuing opportunities to gain additional insights through pursuing LCP-level granularity in Forestry WISE.

This opportunity to take a more surgical approach to line clearing is especially impactful in areas of poorly performing circuit segments within an otherwise well-performing circuit. Not only does this **aid in selecting locations for line clearing,** but also provides higher-level data granularity, reliability prediction, and analytic tool integration that fuels intra-circuit strategy.

- For example, it can take several months for line clearing crews to clear trees along a large circuit, and it is in the best interest of both customers and the Company to first position crews at the worst performing sections of that circuit and prioritize those areas accordingly over the next several months of clearing.
- This strategy prevents more outages within the timeframe of clearing than otherwise clearing the circuit from one end to the other.

The Company is also capturing Light Detection and Ranging ("LiDAR") imagery to inform and support the execution strategy of LVD line clearing tactics in relatively high-risk wildfire areas. The Company is proposing to continue this annually to evaluate the benefits of utilizing this data on a small scale first, before re-evaluating expanding this to a larger scope, up to and including LVD system-wide utilization.

This supports the Company's phased approach to imagery analysis utilization: short- to medium-term utilization of zero- to low-cost satellite imagery analysis and focused LiDAR projects during the ramp-up to a five-year cycle, and long-term re-evaluation of larger scope LiDAR acquisition and utilization to further reduce outages once the LVD system is fully on the five-year cycle.

Service Restoration

The Company's Service Restoration program prepares for and executes work related to public emergencies and restoration activities for all outage categories, including MEDs[11] and Catastrophic Events[12].

This work includes addressing hazards such as broken poles, wire downs, and emergency orders. In addition to the workplan projections, this program includes the non-capital portion of standby costs and on-call costs for resources, such as travel, lodging, and food costs for storm responders.

Current Service Restoration Capabilities

In normal operations, the Company makes available approximately 140 crews and 60 electric service workers ("ESWs"); this can vary based on vacations, sick leave, and training. This enables the Company to respond effectively to approximately 40,000 customers experiencing an outage in a 24-hour period before additional resources are required.

When severe weather or a storm creates incidents beyond the Company's standard capabilities, the Company may need additional crewing and will reach out to off-system crews to supplement the Company's resources.

- Off-system crews are primarily obtained as necessary from other utilities, municipalities, and contractors, and are deployed when all Company resources are engaged.

The Company uses an Incident Command System ("ICS") to address emergency situations, and storm response is always addressed through an ICS.

Within the Company's ICS, crew-to-dispatcher ratio is maintained at no greater than 15 to 20 points of contact with field personnel. To control the number of points of contact, field leaders obtain work from dispatchers and issue work assignments to five to seven crews, allowing for a greater span of control and efficiency with field personnel.

The Company uses an outage prediction model to analyze current weather patterns, past outage history, and machine learning to determine the approximate number of customers and geographic locations that may be potentially impacted. In some cases, the Company may pre-stage resources in locations where severe storm impacts are expected, meaning those resources can be ready to respond as soon as possible after outages occur.

The Company is currently operating four separate control centers, located in three separate facilities in Jackson and Grand Rapids as shown below in Figure 88.

These centers operate 24 hours a day, 7 days a week, with the following general areas of responsibility:

- **The System Control Center**, in Jackson, controls HVD lines and HVD substations.
- **The Distribution Control Center**, in Grand Rapids, controls LVD substations.
- Two **LVD Dispatch Centers**, one each in Jackson and Grand Rapids, controls LVD overhead and underground lines.

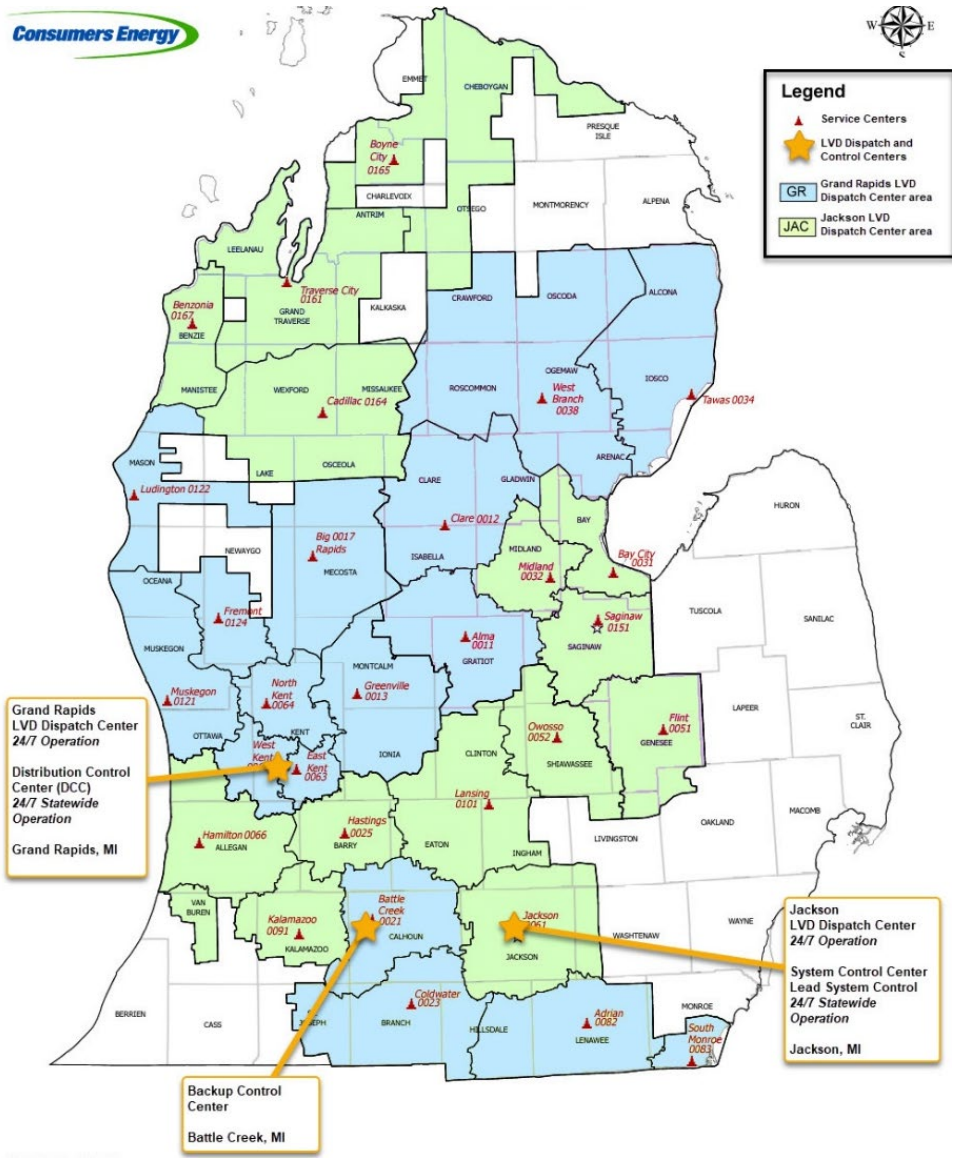
[11] IEEE Standard 1366-2012 defines the methodology for calculating a MED. It is based on a statistical analysis of five sequential years of daily SAIDI values. In 2021, Consumers Energy adopted a refined methodology that transitions from a calendar day evaluation period to a rolling 24-hour evaluation period. This methodology better captures MEDs that straddle consecutive calendar days.

[12] Catastrophic Events is defined in the Public Service Commission *Service Quality and Reliability Standards for Electric Distribution Systems* R 460.702(c).

Staffing in these control centers is increased as required during storm restoration. Storm support is operated from all four centers, depending on the severity and impact to the system, with statewide ICS operations managed from the Emergency Operations Center, also in Jackson.

Figure 88

SYSTEM CONTROL, DISTRIBUTION CONTROL AND LOW VOLTAGE DISTRIBUTION DISPATCH CENTERS



Gray Sky and Catastrophic Service Restoration

High impact Gray Sky storm events (greater than 1% but less than 10% of a utility's customers are out of power) and Catastrophic Storm events (greater than 10% or nearly 190,000 customers of a utility's customers are out of power) provide the greatest challenge and opportunity for the Company to improve Service Restoration performance.

The investments outlined in this plan will result in fewer outage events; the Company will realize savings from having to restore fewer outages, but those savings will be more than offset by the cost to add incremental Service Restoration resources to meet the improved restoration times required in the *Service Quality and Reliability Standards for Electric Distribution Systems* that were implemented in April 2023.

As a result, the Company's strategy is focused on controlling costs through improved productivity and waste elimination.

- To illustrate this point, in August 2023, the Company acquired a record level of Electric Line Crews to restore customers following a catastrophic storm (660 crews) but did not achieve the 90% customer restoration MPSC Performance Standard within 48 hours.
- Contrasted with the August 2023 Storm, the August 2024 Catastrophic Storm enabled the Company's fastest restoration of 150,000 customers (<42 hours), with 500 crews.

The Company was able to restore 95% of customers within 48 hours. This was tied to a deliberate approach to improve productivity and eliminate waste. Through month-end November 2024, the Company has spent $30M less O&M versus 2023; this is despite more storms (small and large) and more outages. Through waste elimination, Consumers Energy has improved field productivity by 13%.

To meet the MPSC Performance Standards and meet customer restoration expectations, the Company will need to continue to balance costs with productivity.

The Company's service restoration planning begins several days prior to an actual event. Meteorologists develop forecasts that are incorporated into an outage prediction model.

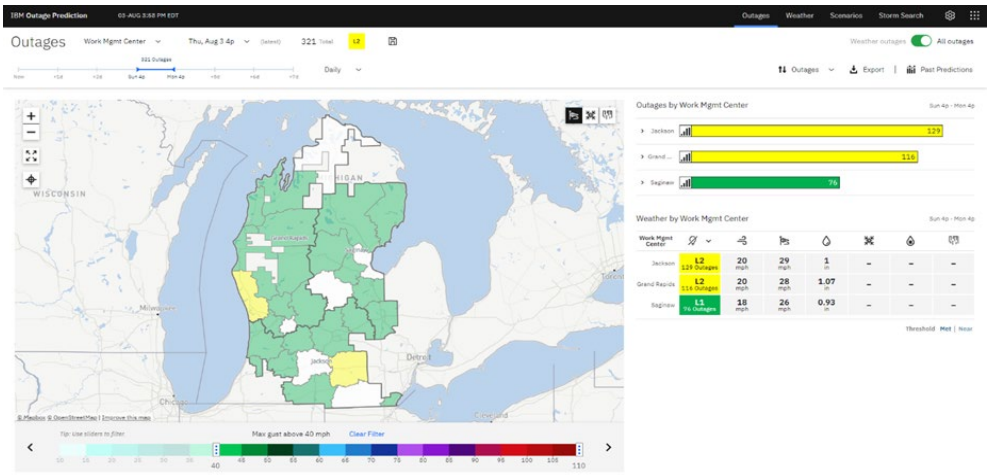
Figure 89 is a snapshot of our prediction model. The boundaries of our service centers are outlined within the State. The model is run every hour each day. Service areas with elevated outage forecasts are visibly displayed.

In the example below, our Emergency Response team used the model to ensure sufficient resource availability to respond to elevated outages in our Grand Rapids and Jackson Work Management Centers.

Written weather forecasts are received every 12 hours; 365 days a year to inform our prediction model. This ongoing planning cycle ensures we have restoration plans in place to meet or exceed acceptable levels of restoration performance.

Figure 89

OUTAGE PREDICTION MODEL



Workplan

In addition to meeting performance levels for customers set by the Commission[13], **the end goal for Service Restoration is a minimum frequency and quantity of outages,** as well as reduced response time for resources, optimal operational efficiencies between control centers, and maximum on-the-job time for field resources.

As described earlier in *Non-Load Challenges* from the Challenges from Customer Technology Adoption section, the electric grid is expected to become much more complicated with DERs coming online at the distribution level of the grid.

This increase in DERs will aid with the transition to a two-way power flow with more renewable generation; however, managing this shift in grid operations requires optimized communication with those employees who operate the electric grid.

To achieve both internal and MPSC defined goals, the Company is consolidating Distribution Control, LVD Dispatch, and System Control centers into two fully staffed Control Centers—one in Jackson and one in Grand Rapids. Each center will serve as a backup for the other, with associated process and organizational changes delivering significant customer benefits.

This consolidation is key for implementing grid operation improvements under all conditions including:

- Improving communications with the co-location of Grid Operators.
- Adopting an optimized demarcation of responsibilities among the groups managing the grid.
- Increasing the authority of field resources to manage outage incidents.
- Ensuring continuous operations during disruptions by having two fully staffed control centers that can back each other up.
- Faster and more effective response to emergencies, minimizing downtime and maintaining service reliability.
- Reduction in System Average Interruption Duration Index (SAIDI) through improved storm readiness and operational efficiency.

The cost savings will be attained by:

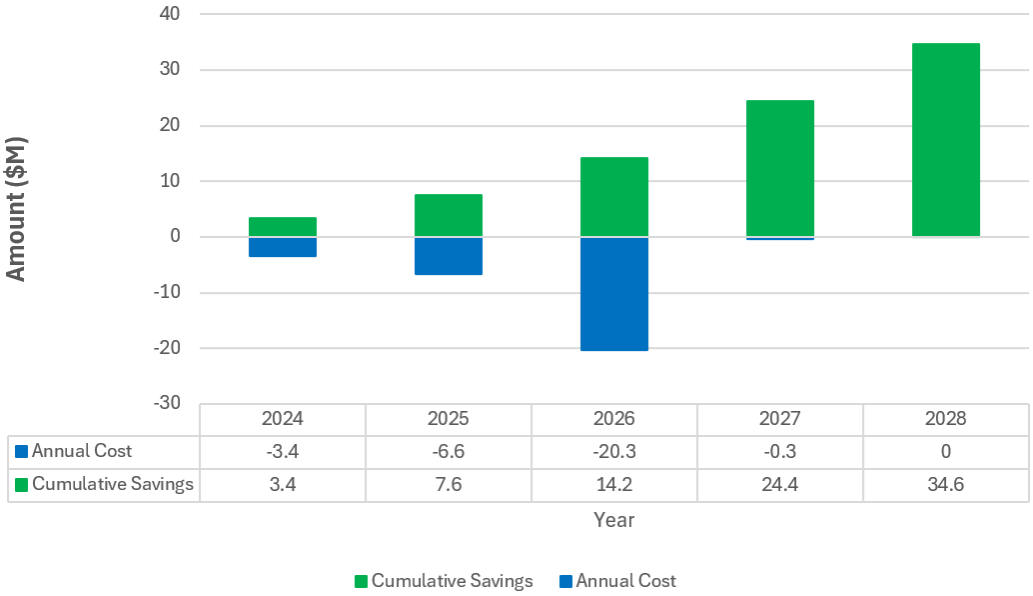
- Balancing storm and non-storm resources and workload to be able to run 70% of storms without activating ICS (typically storms below 50,000 customers).
- Improving processing efficiencies of outage incidents by using automation, and leveraging data provided by Line Sensors, ADMS, and other Supervisory Control and Data Acquisition (“SCADA”) devices.
- Reduction of overtime for field and office resources

The Company’s consolidation of the Distribution Control, LVD Dispatch, and System Control centers into the UCC will cost $30.7 million over four years.

[13] Unacceptable levels of performance are defined in the Public Service Commission *Service Quality and Reliability Standards for Electric Distribution Systems* PART 2.

Figure 90

UNIFIED CONTROL CENTER ANNUAL COST AND CUMULATIVE SAVINGS



In concert with UCC, investments in technology, analytics, and grid modernization are key enablers for our Restoration Management team to meet service restoration expectations.

HVD Asset Management

The HVD system comprises all assets from the point of interconnection with the transmission provider through the point at which LVD lines exit LVD substations.

The HVD system is the backbone for the entire distribution system. Investments in the HVD system ensure that the foundation of the distribution system is reliable and resilient, as HVD outages impact thousands of customers and entire communities at a time. Reliability is accomplished through addressing deteriorated, obsolete, and failing assets.

This section will focus on each HVD asset in detail, with a comprehensive overview of major risks, and the workplan to mitigate risks and five-year investment category for each asset class including:

- Mitigating the risks from deteriorated switches, poles, pole tops, and conductor through **HVD Lines investments**
- Mitigating the risks from deterioration through securing, inspecting, and upgrading **HVD and LVD Substations**
- Enhancing and modernizing the protective system with **System Protection Relays**
- Ensuring the HVD System can serve electric peak demand, new interconnections and support economic development through **HVD Load Growth & Interconnections**

Trees are a significant external risk factor for HVD Lines, and the Company has an HVD line clearing program to address this concern.

As with LVD investments, each HVD asset investment plan includes the planned capital expenses to construct the distribution assets, and the O&M expenses for preventative work, compliance requirements and emergent repairs.

Adequate funding for capital as well as O&M is vital to ensuring both the reliability and cost efficiency of the distribution system through taking proactive measures to address problems before they occur. Continued funding of O&M and adherence to O&M standards provides:

- Increased reliability and resiliency by avoiding outages due to equipment failure or mis-operation.
- Decreased costs by avoiding emergency repairs, allowing for more predictability in the workplan.
- Extension of asset life, avoiding emergent capital replacements and allowing for more predictable future capital investments.

HVD Asset Health Model

The Company evaluates the asset health of HVD lines and substation assets through annual inspections, maintenance, and diagnostic testing.

These key data points are reviewed and collected to build an asset health model, used as a tool for prioritizing investments by evaluating all assets that face declining asset health.

The asset health model considers multiple inputs like asset type, manufacturer, condition, age, actual outages, and level of degradation collected about the asset during inspections, maintenance, and/or annual diagnostic testing to provide a holistic view of the asset's health.

For each type of asset, the asset health model incorporates critical asset factors such as inspection results and testing results, plus known manufacturing issues that affect certain types of equipment. In the case of substation transformers and breakers, asset age is also one of the factors included in assessing risk, because these assets have a known correlation between age and failure.

An HVD line's asset health score combines multiple data points that include if it is a radial line or not, potential customer impact, type of conductor, configuration, number of trips, number of lockouts, red tagged poles, and victor insulators.

Figure 91 below shows the point value assigned to each factor of a line segment that helps generate its overall health score, and Figure 92 shows a sample calculation of a line segment health score.

FIGURE 91

HVD LINE ASSET HEALTH WEIGHTING

Radial line	Points per mile	5
Customers	Points per 1,000	2
Obsolete conductor	Points per mile	5
Unshielded conductor	Points per mile	1
Top 25 contingency	Yes	0
Trip	Points per trip	1
Lockout	Points per lockout	2
Rush red tagged pole	Points per pole	2
Planned red tagged pole	Points per pole	1
Victor insulators	Point per insulator	0.3

FIGURE 92

HVD SAMPLE HEALTH SCORE BY LINE SEGMENT

Line Name	Total Point	Radial	Customer Impact	Obsolete Conductor	Unshielded	Victor Insulators	Red Tagged Poles	Lockout
Line Segment A	133	30	6	0	0	60	25	12
Line Segment B	100	0	10	50	10	0	30	0
Line Segment C	86.6	25	5	0	0	3.6	45	8

An HVD substation's asset health score combines the scores of multiple components within the substation. Figure 93 below shows an example of an asset health score for a substation, showing how multiple component scores total the station score. Figure 94 shows how transformer factors impact the total score for the transformer.

FIGURE 93

HVD SAMPLE HEALTH SCORES FOR SUBSTATIONS

Category	Points per Occurance	Sub A	Sub B	Sub C
AC/FP/REC Wound	25	0	0	0
Age 50+	20	1	1	1
Oil or N2 Leaks	10	1	1	0
Transformer Internal Infrared	10	0	1	0
DGA Score	20	1	0	0
Brand A Bushing Issue	15	1	0	0
Brand B Bushing issue	5	0	0	0
IR P1/P2	20	0	1	0
Doble or Elec Test Issues	15	0	1	0
Transformer & Bushings Total		65	75	20
REG/LTC TOA R3/4	25	1		
IR P1/P2	20			
REG/LTC Total		25	0	0
OCB > 50 Yrs; GCB > 25 Yrs	5	7	3	1
3PH Reg/LTC Demand Order	10	1		
BRKR Oil or SF6 Gas Quality/Leaker	15		1	1
IR P1/P2	15			
Maint/RP Priority List	10			
Oil and Gas Circuit Breakers Total		45	30	20
99 & Cap Bank CSWs/VSW Issues	15	1		
SPT Watch List	10	2	1	1
Str & Concrete	5	1		
Other	5			
IR P1/P2	15		1	1
Ops Limiting Equip	20	1		
Station & Other Totals		60	25	25
Total Score Normalized		100	66.66667	33.33333
Gross Total		195	130	65

FIGURE 94

TRANSFORMER ASSET HEALTH WEIGHTING

Factor	% of Total Score
Age over 50+ years	14%
How the Transformer is Wound	18%
Nitrogen Gas or Oil Leaks	7%
Allis Chalmers Infrared	7%
Dissolved Gas Analysis	14%
Bushing Type	4-14%
Electric Testing Results	11%

HVD Lines

Figure 95

EXAMPLES OF HVD LINES



What HVD Lines Do

HVD Lines carry electric power at high voltage from a source substation to several substations.

HVD Poles are comprised of a pole top, which includes cross-arms, insulators, conductors, and switches that sit atop a wooden or steel pole.

Line miles in Service Territory

The HVD system is comprised of around 4,600 total miles, with approximately 4,400 of those miles being 46 kV and 69 kV overhead lines, and 19 miles being 46 kV underground lines. Approximately 200 miles are 138 kV overhead lines, and 4 miles being 138 kV underground lines.

Lifecycle Analysis

The overall average lifecycle of an HVD line is 60 - 70 years for the physical HVD poles. The life expectancy for pole top hardware, such as cross-arms, insulators, and cross-arm braces, is 30 - 35 years or roughly half the life of poles.

Safety Risks to the Public

HVD Lines represent a minor public safety risk since the height from the ground makes public contact exceedingly rare, however, the deterioration of the Company's HVD poles shows that poles that fail can reach ground level either from deterioration, storms, or vehicle accident.

HVD Line Asset Management Health and Risks

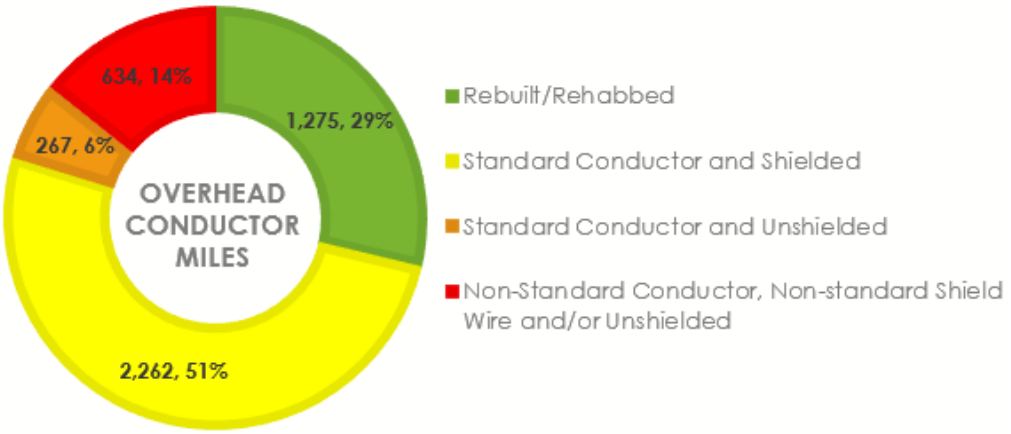
Conductors

'Non-standard conductors' made from copper or small single layer aluminum conductors with a steel core wire do not meet the Company's present design standards. This is due to the increased probability of an outage from icing conditions, weather events or tree incidents compared to multi-layer aluminum conductors.

- Previously installed copper conductors have become obsolete across the industry, making maintenance and procurement of replacement parts difficult.
- These conductors were installed between the 1930s and 1950s on 40'-55' poles that are more susceptible to tree-related outages, due to their short height compared to today's design standards. Outages that occur on non-standard lines constructed with these styles of copper or small single layer aluminum conductors are regularly of longer duration and increased cost due to complexities in working with the degraded conductor.

The most recent Company assessment of HVD conductor health shows nearly 14.4% of HVD conductors are a high priority for repair and replacement based on being non-standard conductor and/or unshielded. Another 6% are in the moderate concern category, based on being unshielded, as shown in Figure 96 below.

FIGURE 96
HVD LINES CONDUCTOR HEALTH



Insulators

Over the past five years, on average, **insulators have been the largest contributor to customer minute interruptions on HVD lines**. These failures are driven by vintage insulators, including victor type insulators.

- The Company has approximately 15,000 victor type insulators that were installed between 1969 and 1994, and their replacement is prioritized in this plan.

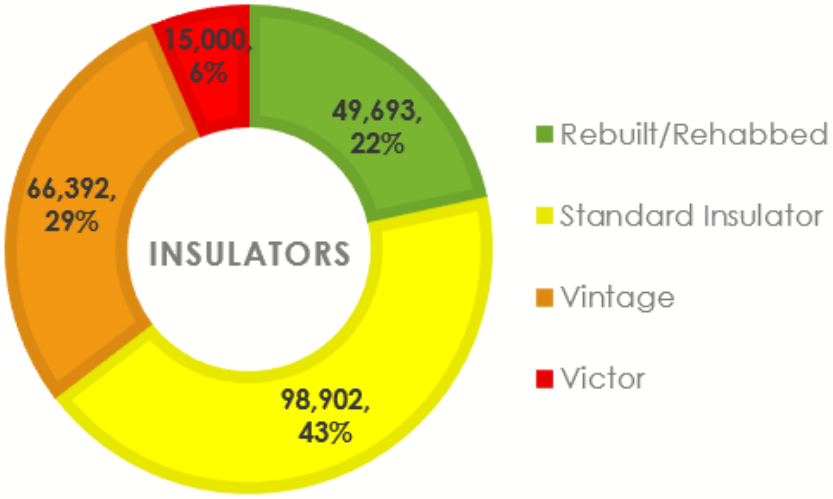
The Company has been leveraging artificial intelligence software and machine learning to automate the review of annual helicopter inspection video, which helps identify specific locations of vintage insulators, including victor type insulators.

As insulator locations are identified via machine learning, the Company can categorize the different types of insulators to enable improved planning of replacements.

The most recent Company assessment of HVD insulator health shows 6% of HVD insulators are victor type insulators and are a high priority for repair and replacement, and another 29% are in the moderate concern category as vintage insulators.

FIGURE 97

HVD LINES INSULATOR HEALTH



Poles

The Company currently maintains a 12-year cycle for HVD pole inspections.

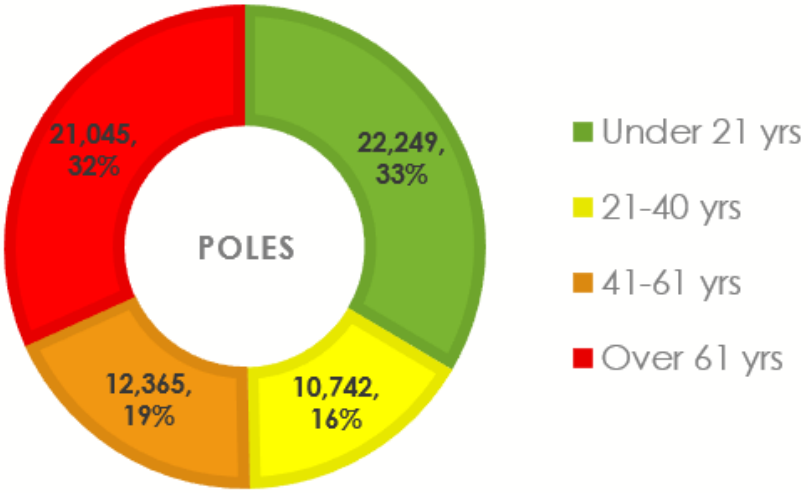
Pole inspections identify poles as candidates for replacement, regardless of pole age. Currently, the Company has a backlog of approximately 2,500 identified poles from inspections prior to 2025 that are in need of replacement, in addition to those newly identified in ongoing inspections.

The most recent Company assessment of HVD pole health shows one-third are over 60 years old, with 19% being between 40 and 60 years old, as shown in Figure 98 below.

While age is not determinative of the need for replacement, increasing HVD pole age generally indicates that to the Company will find increasing numbers of poles to replace during annual pole inspections, as more poles approach the end of their engineered lifecycle.

Historical data shows that 8-12% of HVD poles inspected each year will fail inspection and be identified for replacement. The Company incorporates this data into the overall system condition and defines a plan to replace the poles. This pole inspection is in addition to annual helicopter and ground patrol inspections of all HVD lines that are described in more detail later in this section.

FIGURE 98
HVD POLE HEALTH



Trees

Trees present a potential risk of outage or interruption of electric service on the HVD system.

The Company's *Forestry Line Clearing Program* for HVD is designed to minimize the risk of these occurrences, improve reliable service to its customers, and decrease reactive maintenance and capital expense associated with interruptions during weather events.

The Company clears vegetation within an 80- to 120-foot-wide ROW for these voltages to attain a minimum of 15 feet of separation for 46 kV lines, and 20 feet of separation for 138 kV lines between conductors and vegetation at the time of clearing. This wider clearing standard ensures better reliability and fewer tree hazards on the HVD system.

The Company also manages vegetation within the ROW to maintain accessibility along the ROW for maintenance and repair of the line. The HVD Line Clearing Program is currently on a 4-year clearing cycle.

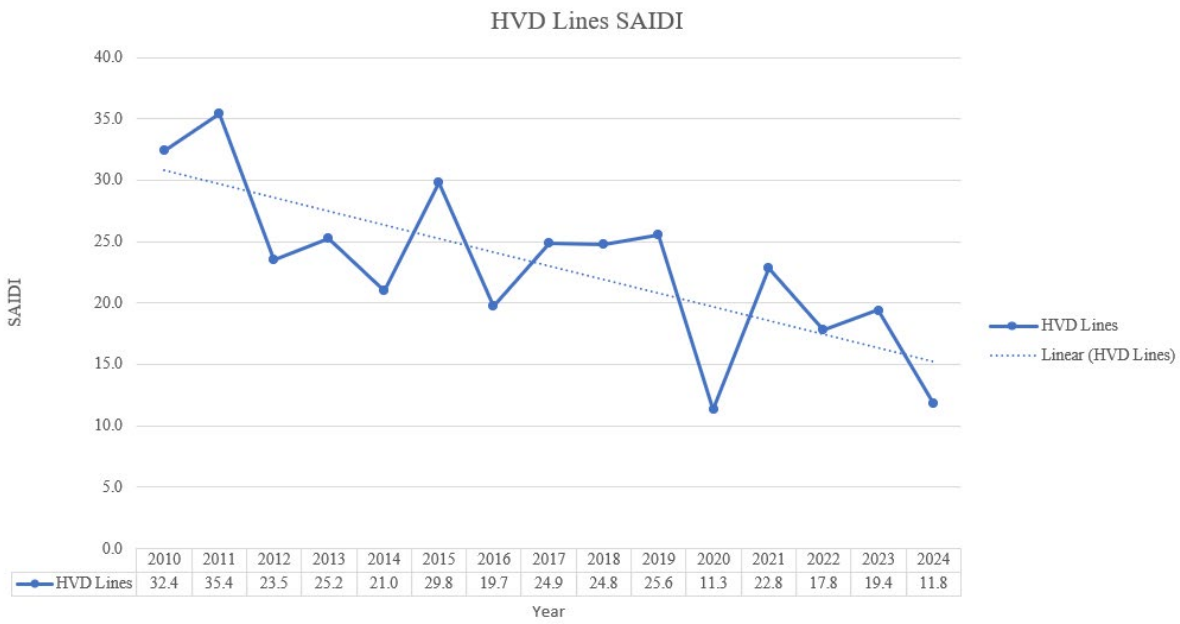
Investments to Address HVD Lines Asset Health

The Company plans to fix and fortify the HVD lines system by replacing deteriorated assets that poses a heightened risk of failure, as identified by inspections. In addition, the Company will address HVD lines identified through the asset health model as being in poor asset health, considering conductor type, configuration, outages, and insulator type.

The Company focuses on lines with consistently poor reliability performance and looks for the best remediation strategy to prevent future outages in the most effective and economical way. After addressing defects identified through inspection practices, the **primary driver for investment decisions is line performance**—lines with the highest average of incident rates and customer outage minute totals in a rolling three-year period are given higher priority for remediation.

As Figure 99 below shows, the reliability performance of the HVD system has steadily improved due to the Company's aggressive investment in HVD lines.

FIGURE 99
HVD LINES SAIDI PERFORMANCE



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
HVD Lines	32.4	35.4	23.5	25.2	21.0	29.8	19.7	24.9	24.8	25.6	11.3	22.8	17.8	19.4	11.8

The Company's HVD lines investment priorities address the system health risks of victor or vintage type insulators, non-standard conductors, and deteriorated poles, pole tops and switches identified through inspection practices.

While this has SAIDI benefits, the larger impact is the avoided outages that never occur when the Company addresses deterioration w a high likelihood of impacting thousands of customers per incident.

As can be seen in Figure 100 below, since 2022 the Company has seen a significant increase in avoided SAIDI identified through inspections, which indicates that the system is deteriorating faster than assets are replaced through planned work.

Based on regular inspection results and annual planning the Company will use the following approaches to improve the performance and longevity of all HVD lines:

Repair and Replace Deteriorated Assets

The Company monitors the health of its HVD line segments based on multiple factors including actual outage history, conductor type, shielding, line configuration looped or radial, insulator type, and the potential customer impact if the line segment were to fail. This provides a first cut for Company engineers regarding where preventative outage work would be most beneficial.

The Company also performs an annual reliability planning review of its HVD line sections, considering both line performance and line condition, to determine which lines and line components need to be addressed in the next year or years, as some projects may be large enough to span multiple years.

The Company addresses asset and line health using a combination of line rebuilds, pole top rehabilitation, switch replacements and pole replacements to reduce the population of these risks and improve reliability performance.

- With few exceptions, lines that use non-standard and obsolete construction or equipment are rebuilt to the modern standard with a new insulator, conductor, cross-arms, structure replacements, tree clearing, and ROW procurement as needed.
- Lines that use standard construction and conductor, and have adequate pole health, but have deteriorated pole top equipment and/or, vintage insulators are rehabilitated via pole top rehabilitation instead of a complete rebuild.
- Switches found to be inoperable or failing are replaced with new switches equipped with SCADA controls, allowing them to open and closed remotely to reduce customer outage time.
- The Company's overall HVD Lines workplan to rebuild or rehabilitate lines and replace poles, pole tops and switches to address the long-term asset health of the HVD Lines systems will on average will touch 4,300 structures, impacting approximately 13,000 insulators and 50 switches per year.

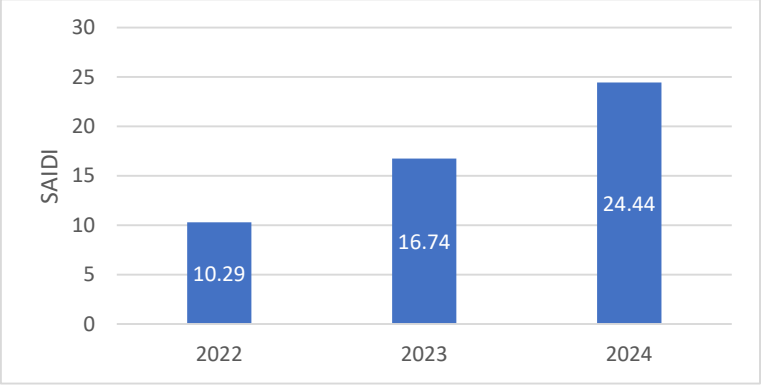
HVD Annual Line Inspections

The Company inspects HVD lines annually, addresses the anomalies found, and fixes defects before they cause a customer interruption.

- More than 4,200 miles of HVD line inspections are performed by helicopter each year, using visual observation and with infrared and ultraviolet cameras to detect anomalies and deterioration before a failure occurs.
- For safety reasons, helicopters do not fly approximately 400 miles of the HVD system. This is because it is difficult to land quickly and safely in the event of an emergency. Most of these "no-fly lines" are in densely populated urban areas. To inspect these lines, the Company completes biannual ground patrols that may include infrared and/or corona inspection using handheld cameras.
- The Company's pole inspections not only identify poles that need to be replaced in the coming year, but also poles that require immediate attention. The poles are addressed in an expedited manner to prevent outages to customers.

As the Company identifies anomalies through its inspections, it mitigates any defects identified during inspections that would fail within months and cause interruptions to customers if not addressed (anomalies are typically addressed within one to two weeks of identification). The Company then calculates the SAIDI minutes that would result if the affected asset failed and caused interruptions to customers. These avoided SAIDI minutes in historical years are shown in Figure 100 below.

Figure 100
HVD SAIDI AVOIDED THROUGH INSPECTIONS



Operations and Maintenance (O&M)

As described earlier, the Company uses aerial, ground, and pole inspections to assess the condition of the HVD Lines system.

Funding of the operations and maintenance program for these inspections provides increased reliability by identifying equipment nearing failure and making repairs before an outage can occur.

O&M funding is used to support inspections, as well as O&M related corrections to HVD lines assets like fixing hot connections, splices, broken guy wires, calibrating switches, and removing trees from lines during outages.

The Company has seen a continued reduction in HVD Lines SAIDI minutes because of an increased investment in HVD Lines asset health, with a focus on line and equipment inspections, and preventative maintenance.

Even with a downward trend in SAIDI, the *Reliability Roadmap* will require additional O&M funding to sustain this momentum. The increased O&M funding would be used to increase helicopter inspections, expand switch and pole inspections, and to repair all anomalies identified during the inspections.

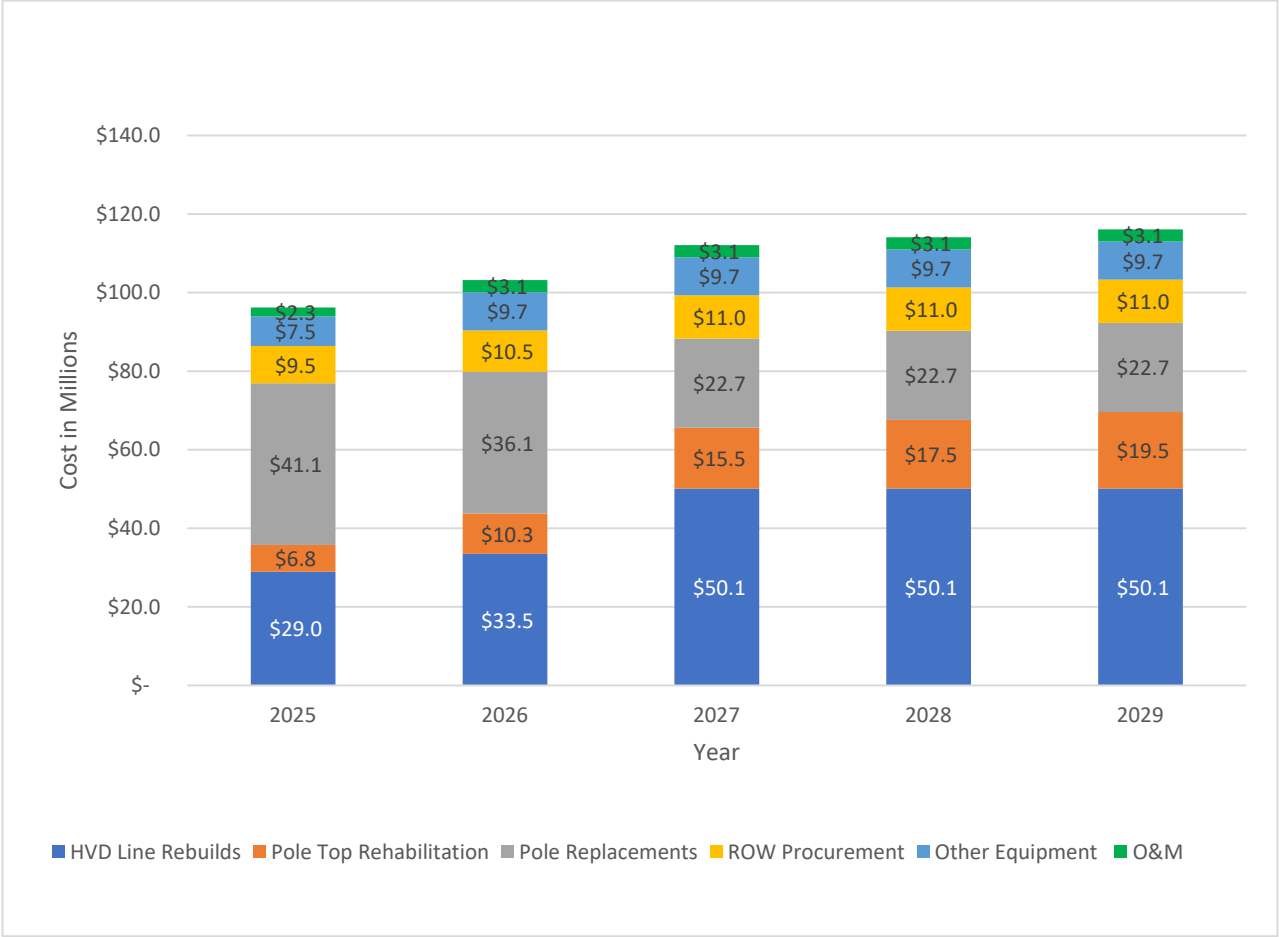
5-Year Investment Plan

The Company will rebuild or rehabilitate an average of 175 HVD line miles per year and replace approximately 1,200 poles per year as part of this plan to support the company's reliability goal.

The 5-year investment plan for HVD Lines is below.

Figure 101

HVD LINES 5-YEAR INVESTMENT PLAN



Year	HVD Line Rebuild Miles	Pole Top Rehabilitation Miles	Pole Replacements
2025	10	41	1,508
2026	47	91	1,323
2027	77	94	830
2028	77	115	830
2029	77	135	830

Substations

What Substations Do

The purpose of a substation is to receive power at one voltage level and transform that power to a different voltage level for different purposes depending on the type of the substation.

Types of Substations on Consumers Energy's System

The Company has HVD, LVD, SEC, and mobile substations, which all have a specific purpose. HVD substations receive power from the METC transmission system and reduce the voltage to feed the Company's HVD Lines system, which in turn feed the Company's LVD substations.

LVD substations take power at transmission or sub-transmission voltage levels and step it down to LVD levels, so it can be distributed to households and businesses. **LVD substations,** as shown below in Figure 103, **are the interface point between the HVD and LVD systems.** LVD lines emanate from LVD substations to deliver power to customers.

There is a subset of substations dedicated to serving single industrial customers; these are classified as *Strategic Electric Customer* ("SEC") substations, like the one shown below in Figure 104.

FIGURE 102
HVD SUBSTATION



FIGURE 103
LVD SUBSTATION



FIGURE 104
SEC SUBSTATION



The Company maintains a mobile substation fleet to provide electric service to customers during planned and unplanned substation outages where redundancy is not present or load transfers to adjacent substations are not available.

- Mobile substations are vital to the Company's ability to maintain and operate substations because substation projects and repairs can take several days to several months to complete.

Mobile substations are also deployed to support HVD Line projects, to prevent outages for emergent concerns, and to restore electric service during unplanned outages. An example of a mobile substation is shown in Figure 105.

FIGURE 105
MOBILE SUBSTATION



Number of Substations in Service Territory

The total substation network currently consists of 1,135 Company-owned substations and 64 customer-owned substations.

- The HVD substation network consists of 144 HVD substations and 163 SEC substations.
- The LVD substation network consists of 828 general distribution substations.
- In addition to the Company-owned HVD and LVD substations, there are 35 customer-owned dedicated substations, 5 Company-owned substations providing wholesale distribution services to rural co-op and municipal systems, and 30 customer-owned substations providing wholesale distribution services to rural co-op and municipal systems.
- The mobile substation fleet currently consists of 30 mobile units with varying electrical capacity, electrical configuration, and service function.

Lifecycle Analysis

Substations are a collection of several key components that determine the health and longevity of the Company's substations.

The overall average engineered lifecycle of key substation and mobile substation components average 50 years, including Power Transformers, Circuit Breakers, and Switches.

Safety Risks to the Public

Substations represent a minor public safety risk because of the barriers and fencing surrounding the assets, making accidental public contact exceedingly rare.

In the case of mobile substations, safety barriers can be erected inside of existing substations or outside with fencing.

Substation Asset Health and Risks

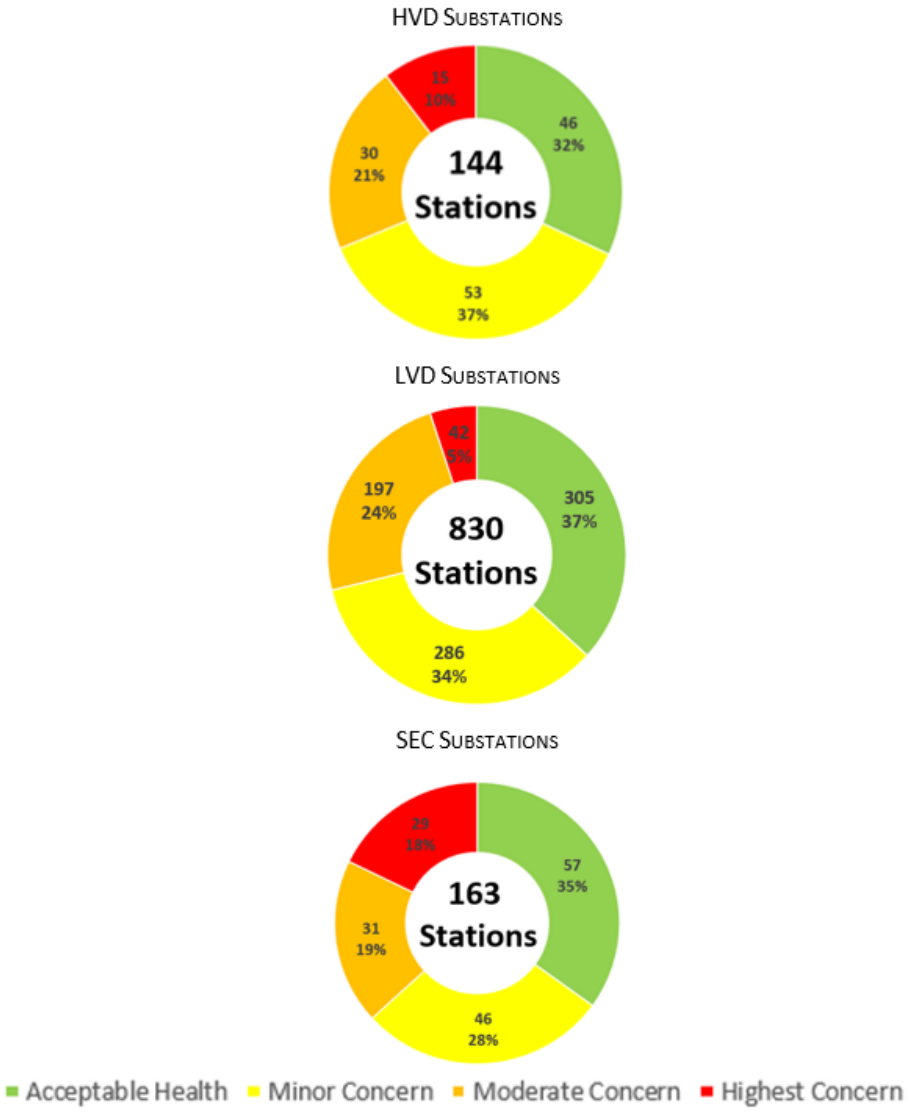
Substation health represents an overall assessment of equipment data and component evaluation for each substation.

Assessments include items such as equipment condition, equipment type, equipment age, visual inspection data, infrared inspection data, oil and gas test data, and electrical test data.

Four health categories have been created with action plans for each color rating as shown in Figure 106.

Figure 106

SUBSTATION HEALTH



HVD Substations

The most recent Company assessment of HVD substation health shows 10% are a high priority for repair and replacement, with another 21% in the moderate concern category.

Of the remaining HVD substations, 69% of substations are in acceptable health or only show minor concerns as shown in the figure above.

Strategic Electric Customer (SEC) Substations

The most recent Company assessment of SEC substation health shows 18% are a high priority for repair and replacement, with another 19% in the moderate concern category.

Of the remaining SEC substations, 63% of substations are in acceptable health or only show minor concerns as shown in the figure above.

LVD Substations

The most recent Company assessment of LVD substation health shows 5% are a high priority for repair and replacement, with another 24% in the moderate concern category.

Of the remaining LVD substations, 71% of substations are in acceptable health or only show minor concerns as shown in the figure above.

Key Substation Risks

Major Equipment Failures

Some substations in the Company's service territory were built in the 1920s and are approaching 100 years in age, and still employ original equipment.

Old and obsolete equipment such as Power Transformers, Circuit Breakers, and Switches can cause large customer outages if they fail, often at a significant cost.

- Failures at HVD substations are less likely to cause customer outages due to the redundancy built into the station design, but when customers are interrupted it can be upwards of 10,000 customers affected.
- Failures at SEC substations will impact only the customer being served.
- Failures at LVD substations are more apt to cause customer interruptions due to less redundancy in the design, but such interruptions typically affect fewer customers ranging from several hundred to a few thousand.

Physical Security Gaps

Animal contacts from birds, squirrels, and raccoons are some of the most common customer interruptions at substations.

However rare, due to the critical importance of substations to the overall electric grid, the Company must also prepare for the case of intentional coordinated attack at these facilities.

- The customer impact of such an attack would be like that of a major equipment failure.
- Opportunities to mitigate this risk are continually being identified and implemented by engineering and operations teams with support from Corporate Security.
- Opportunities include upgrading substation surveillance systems and adding additional security to equipment to prevent inadvertent operation.

Extreme Weather

Extreme heat or cold will increase loadings on substation equipment and may shorten equipment lifespan, which could result in more frequent replacement.

- Extended periods of extreme cold can affect the operation of breakers, circuit switchers, and other electromechanical equipment.
- While substations typically hold up well to violent winds, debris blowing into a station and creating faults in exposed conductors or equipment poses a risk to substations.

Investments to Address Substation Asset Health

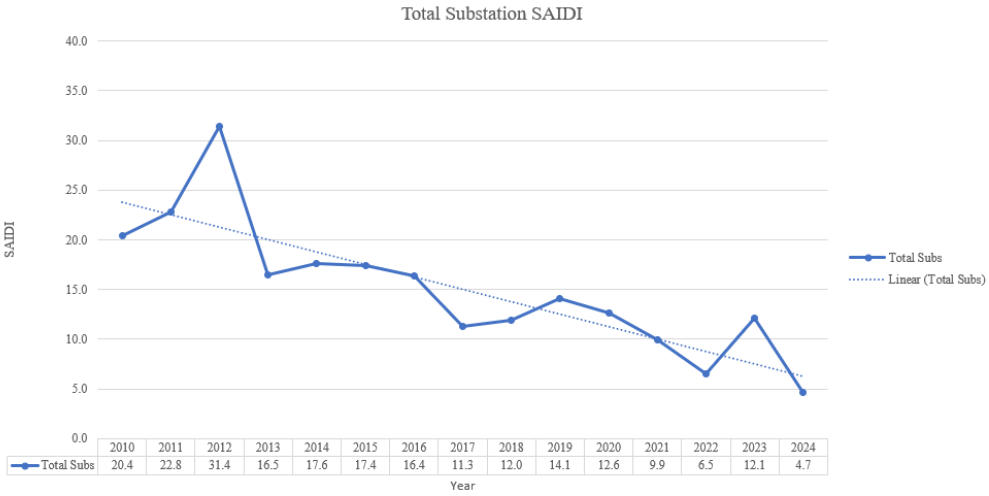
The desired outcome for all substations is to monitor electrical loading, and to provide adequate inspections, maintenance, and end-of-life asset replacement for all substations.

End-of-life is not solely a reflection of asset age. End-of-life is a holistic evaluation of the asset that considers remaining life based on inspection and maintenance findings in addition to the cost of maintaining versus replacement.

The top priority for substations is providing reliable electric capacity to all customers through timely resolution of equipment loading and substation health concerns, new electrical load connections, and substation reliability improvements.

Like HVD Lines, Figure 107 below shows the reliability performance of substations has steadily improved due to the Company's investment in equipment replacement and animal mitigation for both LVD and HVD lines substations.

FIGURE 107
SUBSTATION SAIDI PERFORMANCE



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Subs	20.4	22.8	31.4	16.5	17.6	17.4	16.4	11.3	12.0	14.1	12.6	9.9	6.5	12.1	4.7

The Company has shown that substations, if properly maintained, can operate beyond their average lifespan. However, these assets must be monitored, inspected, and maintained regularly, and repaired in a timely manner if a failure does occur.

To ensure optimal performance and operation of substations, the Company carries out the following actions to properly protect and maintain substations:

Repairing and Replacing Deteriorated Assets

The Company regularly reviews reliability data, inspection data, industry practices, and operation practices to identify end-of-life assets and modernization opportunities to improve overall customer service reliability, improve substation health, and mitigate customer outage risk.

Based on this data, the Company plans to rebuild substations that are at end-of-life or have working clearances that do not meet current standards and operating practices.

- The Company plans to rebuild over 70 substations over the next 5 years, accounting for HVD, SEC, and LVD substations.
- The Company will also purchase six new mobile substations to support planned and emergent projects that improve customer reliability and substation health, and to support outage prevention and outage restoration.

Where possible, the Company seeks to repair and replace degrading assets to prolong the substation lifespan and reduce cost to customers. The Company regularly reviews reliability, inspection, and operating data to identify where substation equipment is degrading, has reached end-of-life, or requires modernization.

Based on this data, the Company plans to replace equipment to mitigate customer outage risk and to resolve decreased service quality.

- The Company will replace degrading equipment such as transformers, breakers, regulators, switches, and reclosers as concerns are identified.
- The Company will replace all transformers and circuit breakers that are beyond end of life.
- This plan will replace an average of 2 HVD transformers, 10 SEC transformers, 30 LVD transformers, and 40 circuit breakers per year over the next 5 years to support the Company's Reliability goal.

Operations and Maintenance

The Company uses maintenance standards for both LVD and HVD substation equipment, referred to as the *Electric Substation Reliability Guidelines* or (ESR-1) that were developed based on vendor recommendations, industry best practices (including EPRI and IEEE) and collective experience by Company personnel. The recommended maintenance activities outlined in ERS-1 are shown in Figure 108 below.

FIGURE 108

ESR-1 RECOMMENDED SUBSTATION MAINTENANCE ACTIVITIES

Category	Activity
NERC/HVD/Strategic Substations	NERC/HVD/strategic substation inspections (monthly)
	NERC/HVD equipment test operating & profiling (annual)
	Motor Operated Air Break (MOAB) switch test operating (annual) and battery exchanges (every 4 - 5 years)
	NERC/HVD/strategic substation infrared inspections (annual)
	NERC required testing and battery maintenance (annual)
	Strategic customer online insulator cleaning (annual, select customers)
	HVD infrared inspections (annual)
	SF6 breaker gas quality testing
	HVD breaker inspections and maintenance
	Circuit switcher inspections and maintenance
	Spring operated ground switch inspections and maintenance
	Capacitor bank inspections and maintenance
	Transformer Load Tap Changer inspections and maintenance
	Station power transformer inspections and maintenance
Category	**Activity**
LVD Substations	LVD substation inspections (bi-monthly)
	Single-phase regulator maintenance
	Single-phase regulator oil samples and dissolved gas analysis (5-year program)
	LVD substation animal mitigation inspection (twice per year, Spring and Fall)
	LVD substation equipment test operating (annual)
	LVD infrared inspections (every other year)

Category	Activity
All Substations	Emergent and planned 'Broke-fix' work for NERC/HVD/Strategic/LVD substations and Metro
	Infrared repairs (Priority 1)
	Third-party switching and tagging support (strategic customers, ITC, third-party generation)
	Substation transformer oil sampling and analysis (annual), Total Combustible Gas testing (annual)
	Substation snow plowing (Every winter)
	Substation weed control (1 application per year)
	Substation mowing (typically twice per month per sub OR more frequent)
	Substation property clean-up and repairs (trash cleanup, homelessness encampment cleanup, control house repairs etc.)
	Misc. items such as: Substation eye wash station cartridge replacements (annual); switch stick, personal protective ground testing and fuse testing (annual)
	Misc costs (fleet loadings, access control/telecom costs, Doble Engineering membership etc.)
	Power transformer inspections and maintenance (limited by outage availability)
	Infrared repairs (Priority 2 and 3)
	Switch repairs
	Facilities O&M repairs

Funding for the O&M standards in ESR-1 provides increased reliability and resiliency by avoiding outages due to equipment failure or mis-operation at a reduced cost by avoiding emergency repairs, which can cost up to 70% more than proactive maintenance. Additionally, the Company's O&M plan **extends the life of assets by avoiding emergent capital replacements** and allowing for more predictable future capital investments.

The Company has seen continued reduction in SAIDI minutes because of an increased operational focus on preventative maintenance.

Despite the encouraging trend in SAIDI, the *Resilient Grid Plan* will require additional O&M funding to sustain this trend, execute required preventative activities, and continue to improve the internal processes to enhance asset management.

Physical Security Gaps and Animal Mitigation

All substations are enclosed within a fence or wall barrier to provide physical security and public safety, and additional measures are installed to mitigate animal intrusions that can result in substation outages.

The purpose of the Company's animal mitigation is to keep large and small animals out of the substation, and to insulate equipment to extend touch potential if an animal gets into a substation, with specific measures chosen based on substation characteristics.

The Company's current animal mitigation standards were developed based on research conducted at Michigan State University, experiments conducted at the Company's Marshall Training Center, utility industry reports and best practices (e.g., EPRI), and experience gained from previous animal mitigation projects.

The Company's animal mitigation measures include:

- 1-inch mesh fence (squirrels can squeeze through larger mesh)
- Concrete gate foundations (minimizes gaps and frost heave that create gaps over time)
- Polycarbonate panels (3-foot panels installed at the top of the fence to mitigate animals from climbing over the fence)
- Pole wraps and line discs (installed on poles and wires outside the substation to mitigate aerial access to the substation)
- Interior and exterior stone (eliminates gaps at the fence bottom to mitigate animals from crawling under the fence)
- Bushing guards on regulators and reclosers to extend touch potential to mitigate contact to energized components if an animal climbs on equipment
- Vegetation management

Animal-caused outages are typically the highest contributor to substation SAIDI, leading the Company to aggressively update animal mitigation at the LVD substations.

Approximately 90.2% of the LVD Substations now have standard animal mitigation measures installed. The Company plans to have animal mitigation installed at 99% of the LVD Substations within the next 5 years.

Distribution Supervisory Control and Data Acquisition ("DSCADA")

DSCADA is **the key component of substation automation, allowing the Company to monitor and control substation devices remotely** without requiring the dispatch of a human operator.

When DSCADA is installed at a substation it includes a Remote Terminal Unit (RTU), a local device that facilitates communications with substation devices and remote software systems and captures over 300 data points.

- The enhanced visibility into substations and the remote-control capabilities allow the Company to address outages more quickly and effectively.
- The enhanced visibility also allows the Company's planning engineers to perform more accurate load flow studies because DSCADA provides access to real-time circuit data.

The remote-control aspects of DSCADA are crucial in enabling advanced automation such as the ATR loops described earlier in the Resiliency Investments section of this plan.

The Company plans to install DSCADA at 100 more substations over the next 5 years.

5-Year Investment Plan

For HVD and SEC Substations, the Company is working through a comprehensive plan to replace components that have failed inspections results and are at end-of-life, and rebuild whole substations where needed.

The plan requires $69 million of capital investment per year until 2035, along with a ramp-up of two years until fully implemented.

Also included is an increase in O&M spending across all Substation Reliability and Demand Failures programs to adhere to the recommended maintenance intervals as defined in ESR-1, provide best practice maintenance of all major equipment, and eliminate the backlog of inspection and repair orders.

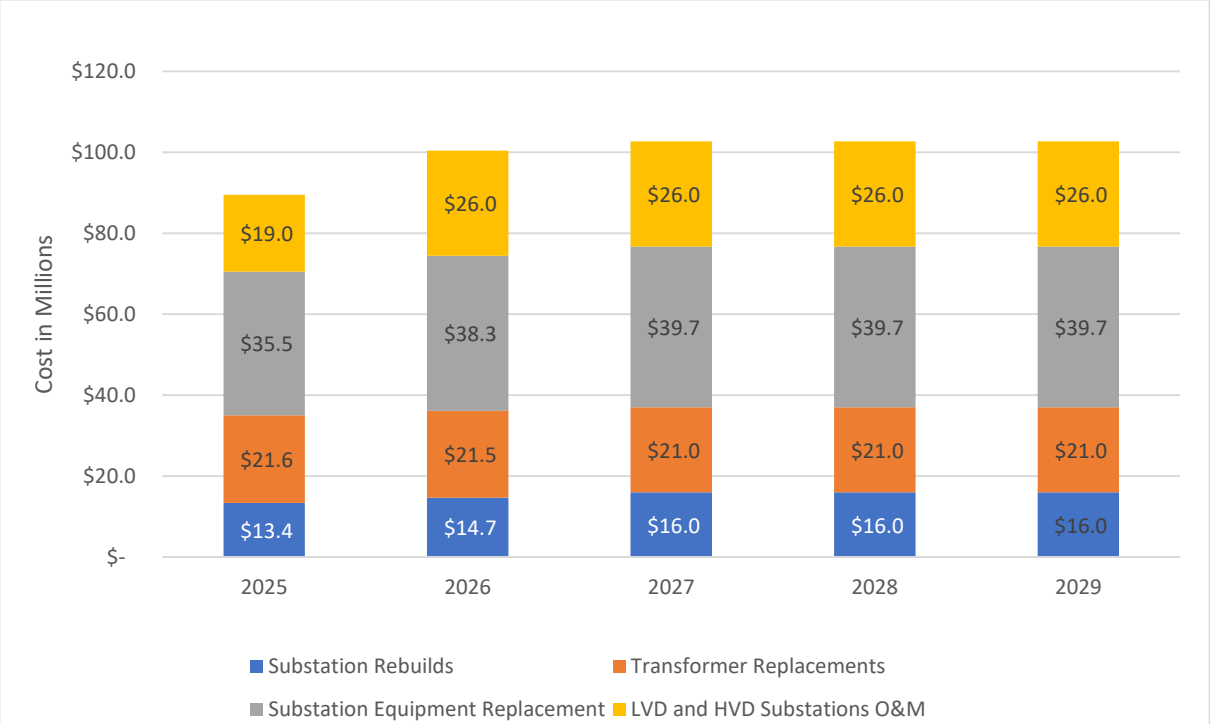
The O&M for both HVD and LVD substations are included in the HVD Substation investment plan below.

- As shown in Figure 109 below, over the next five years this plan will, on average, rebuild 2-4 HVD or SEC substations per year, replace 2 HVD transformers per year, 10 Strategic Customer transformers per year, and 130 piece of substation equipment like breaker, switches, and capacitor banks to support the Company's Reliability goal.

The reliability impact of this work is estimated to result in two fewer HVD or Strategic Customer Substation outages per year.

Figure 109

HVD & SEC SUBSTATION INVESTMENT PLAN



Year	Substation Rebuilds	Transformer Replacements	Equipment Replacements
2025	2	9	220
2026	2	3	190
2027	2-4	12	190
2028	2-4	12	190
2029	2-4	12	190

For LVD Substations, the Company is working through a comprehensive plan to replace components that have failed inspections results and are at end-of-life, rebuild substations, and build new substations where needed.

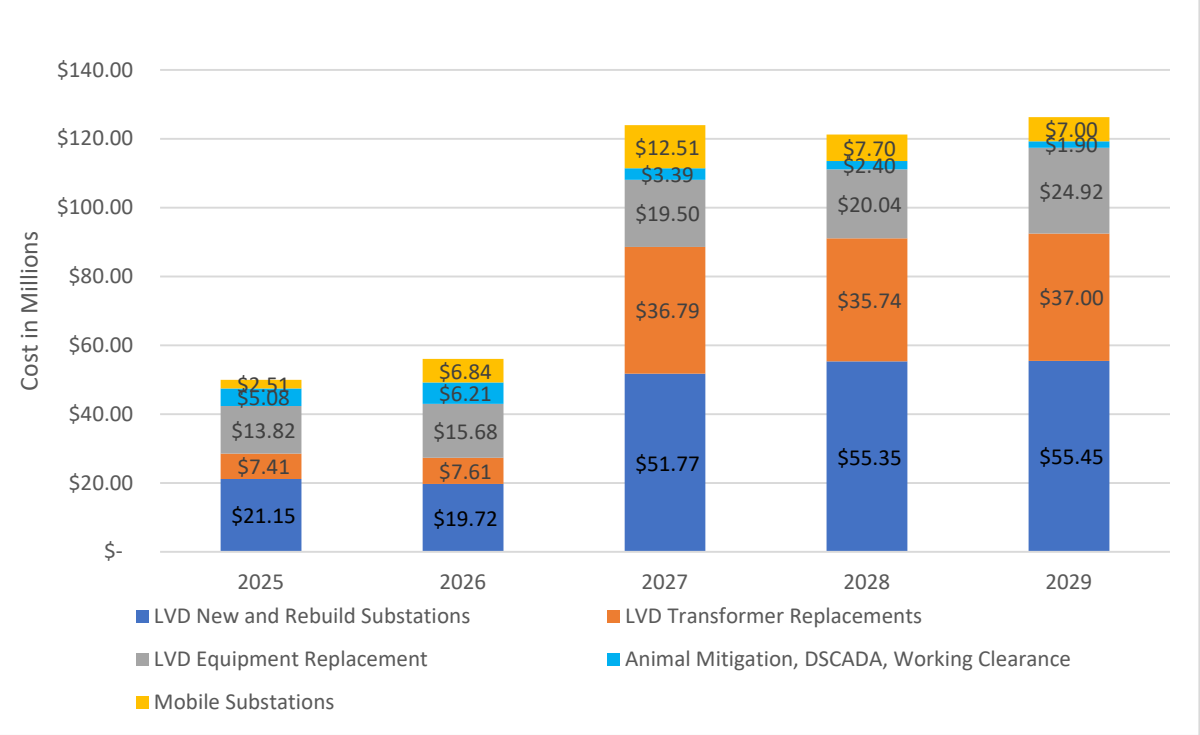
This plan will continue to maintain substations with industry best practices while installing DSCADA at substations for efficient control and monitoring.

- As shown in Figure 110 below, over the next five years this plan includes the building of 20 new substations, the rebuild of 58 substations, the replacement of 151 substation transformers, and the replacement other substation equipment (regulators, reclosers, switches, etc.) to support the Company's Reliability goal.

The reliability impact of this work is estimated to result in two fewer LVD Substation outages per year.

Figure 110

LVD SUBSTATION INVESTMENT PLAN



Year	New & Rebuild Substations	Transformer Replacements	Equipment Replacements	Mobile Substations
2025	13	7	20	2
2026	12	6	15	2
2027	16	35	15	3
2028	17	30	15	2
2029	15	34	15	1

System Protection Relays

What Protective Relays Do

The purpose of a protective system is to **de-energize as quickly as possible** the minimum amount of the electric network that has experienced an electrical fault, to **isolate the fault**, and **mitigate damage** to other equipment.

Protective systems within a substation consist of protective relays designed to trip a circuit breaker when a fault is detected.

Protection systems have two modes of failure.

- The first is **incorrect operation**—when a protective device operates when it should not. This failure mode can cause unnecessary customer outages, and in severe cases, can lead to cascading outages that result in widespread blackouts.
- The second failure mode is **when a protective system does not correctly de-energize an electrical fault**. The failure of a relay to trip properly under fault conditions can lead to severe system consequences, including an extended outage, more customers interrupted than are necessary, equipment damage as lines or transformers burn up, environmental hazards due to ruptured transformers, and public safety hazards due to fires, shrapnel from exploding equipment, and electric shocks due to uncleared electrical faults. Proactively identifying and replacing relays that are prone to failure greatly reduces the risk of these consequences.

Number of HVD Relays in Service Territory

There are 5,237 relays in the Company's service area. A relay unit is defined as a relay panel consisting of 5 electromechanical relays, 10 solid state relays or 2 digital relays.

Lifecycle Analysis

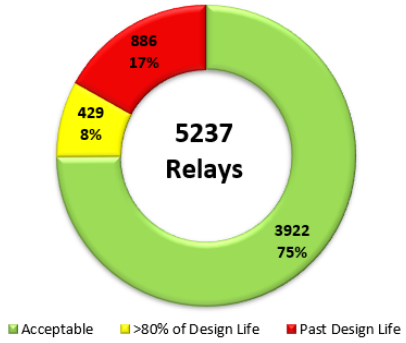
The Company has determined design life for protective relays based on vendor recommendations, industry best practices as documented by the IEEE Power System Relaying Committee, and Company experience with failure of specific relay types.

Protective Relay Asset Health and Risks

The most recent Company assessment of Relay health shows 83% of relays are in acceptable health or have not yet reached the end of their lifecycle, as shown in Figure 111 below. Of the remaining relays, approximately 17% of the protective relay population is older than the designated design life.

As relays age, they are more frequently out of settings tolerance, which can cause interrupting devices (like circuit breakers, circuit switchers, etc.) to open when they don't need to, leading to interruptions, or, not open when they should, leading to larger scale interruptions, equipment damage, and possible safety hazards. More frequent field testing and calibration is required to ensure proper performance.

FIGURE 111
RELAY HEALTH ASSESSMENT



Investments in System Protection Relays

The Company's primary desired outcome for relay health and reliability is to keep all protective relays within design life.

Relay Replacement Plan

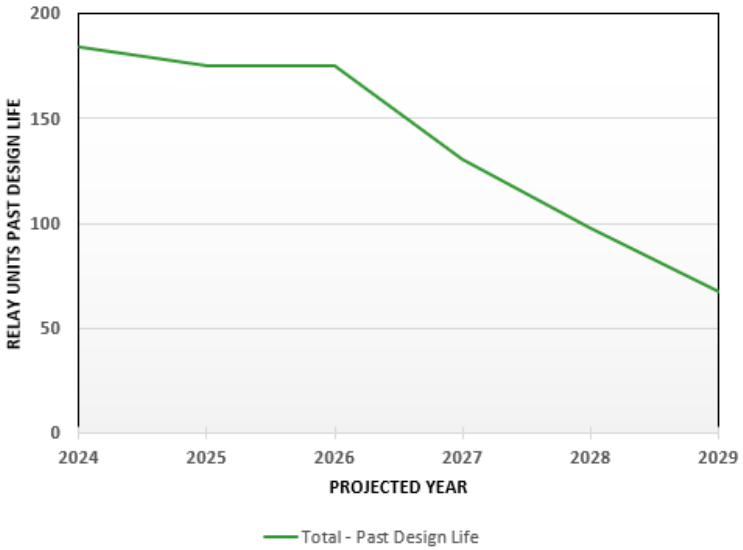
The relay replacement plan is a capital program to replace end of life relays with new modern relays. Multiple factors are considered to assign a risk score to each relay.

- The factors considered include relay age, relay types with a history of malfunctions, substations without digital oscillography, etc.
- The relays are then prioritized based on this risk ranking for capital replacement.

Figure 112 below shows the projected number of relay units that are past design life based on the proposed capital relay replacement plan.

The relay replacement plan will maintain all relays within lifecycle by 2032.

FIGURE 112
PROJECTED NUMBER OF RELAY UNITS PAST END OF DESIGN LIFE



Operations and Maintenance

All relays on Consumers Energy's HVD system are tested and maintained on periodic intervals, and all testing done on the relays is based on manufacturer recommendations.

The intervals are based on the type and function of relay, informed by best practices as defined by NERC Standard PRC-005, and trends observed from historical testing data.

Relays that test out of tolerance are recalibrated or replaced as necessary.

Event Analysis & Corrective Actions

The Company investigates every event on the HVD System to ensure correct operation of the protective systems.

- For all incorrect operations, the immediate cause is identified and resolved.
- For any systemic problems identified, long term corrective actions plans are developed.

System 5-Year Investment Plan

The Company will implement the relay replacements identified above, which requires $5.41 million in 2025, and $4.07 million in 2026, in capital investment.

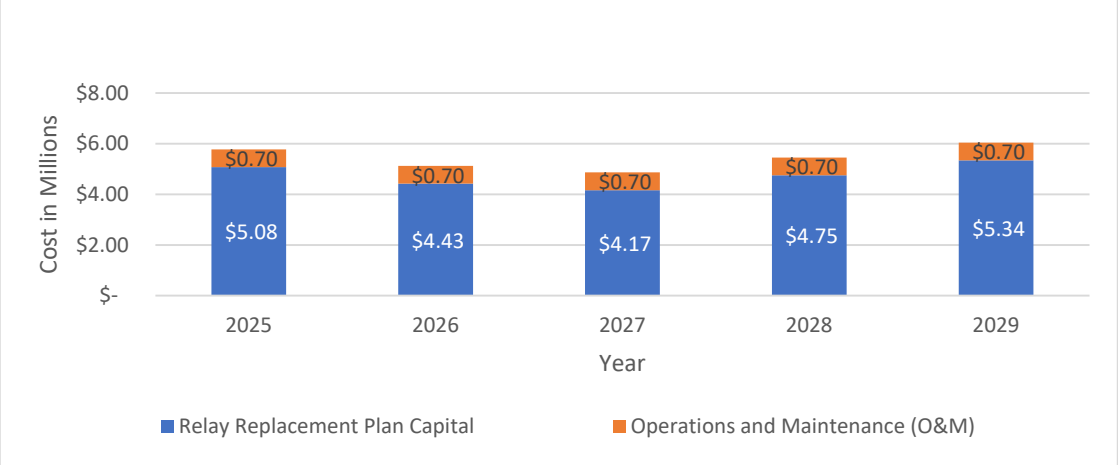
In 2027, the annual spend will increase with inflation as shown in Figure 113 below. The annual investment will increase by $500,000 in 2028 and 2029.

This plan will replace approximately 47 relay units in 2025 and 36 relay units per year in 2026 and 2027. The number of relay units replaced increases to 41 relay units in 2028 and 46 relay units in 2029 to account for digital relays beginning to reach end of life.

The ongoing operational maintenance and corrective actions described above will require $700,000 in 2024, and beyond.

FIGURE 113

SYSTEM PROTECTION INVESTMENT PLAN



Year	Relay Replacement Plan
2025	46
2026	31
2027	36
2028	41
2029	46

HVD Load Growth and Interconnection

HVD Load Growth and Interconnection projects consists of the following:

- HVD enhancements to ensure the HVD system can serve electric peak demand in accordance with HVD planning criteria
- Work to accommodate new interconnections
- Work to improve functionality through standards
- Upgrades to protection
- Operability of the system
- Coordination with transmission infrastructure additions

HVD Load Growth and Interconnection also supports Real Estate and ROW acquisition supporting projects.

Because the HVD system is the backbone infrastructure of the electric distribution network, projects in this sub-program must be completed on an as-needed basis to serve customers and maintain the safety and overall reliability of the grid.

Investments in this sub-program improve system reliability by preventing future overloads. These investments also help avoid dangerous wire downs and equipment failures due to overloads and exceedance of equipment interrupting capability, improving system safety.

Investments for HVD Load Growth and Interconnection

The Company's primary desired outcome for HVD Load Growth and Interconnection is to ensure the HVD system can serve electric peak demand in accordance with HVD planning criteria, accommodate interconnections to the HVD system, and ensure current standards to support improved functionality of the system.

Load Carrying Capabilities and Voltage Support

Load Carrying Capabilities and Voltage Support projects eliminate unacceptably low voltage, and loadings above line and equipment ratings.

The Company studies the HVD system using power flow analysis to calculate the base power flow and voltages, and changes in power flow and voltages resulting from single outages for present and future versions of the HVD system.

New Interconnections

The New Interconnection category encompasses **new interconnections to other utilities and to generation facilities** that must be completed as requested by the interconnecting party.

Costs to interconnect other utilities and generation facilities to the Company's HVD system are reimbursed by the other utilities or generators being interconnected.

Improved Functionality

The Improved Functionality category comprises **projects completed to meet changes in standards, and upgrades** to protective schemes on a planned basis over a period.

- An example of this is the Company alleviating substation NESC working space issues systematically over a 10-year period.
- These projects are often coordinated with other major projects when they occur at the same location.

Configuration changes to improve operability are made at the request of the Grid Management group or through coordination with other major projects when they occur at the same location.

Coordination with Transmission

The Coordination with Transmission projects, such as HVD relay upgrades associated with transmission upgrades, must be coordinated with those transmission upgrade projects that require the HVD upgrades to be completed.

These are completed as needed over time, in conjunction with the transmission owner.

Right of Way ("ROW") Procurement

ROW Procurement projects are necessary to **procure HVD line rights or substation sites for new and/or expanded HVD facilities, as well as rights necessary to maintain existing HVD facilities**. These projects are critical to prepare for HVD construction and for maintaining existing HVD facilities ,and can require significant lead time.

Acquiring the necessary land or land rights is integral to advancing HVD lines and substation projects.

These projects must be prioritized to adequately support the project that is depending on the new rights (e.g., new HVD line, HVD line relocation or rebuild off-center, new HVD or LVD substation, or improved easements where rights are determined to be inadequate).

Through the process of monitoring and studying load profiles, properties are sought and procured to build electric infrastructure at the right point in time needed to serve customers.

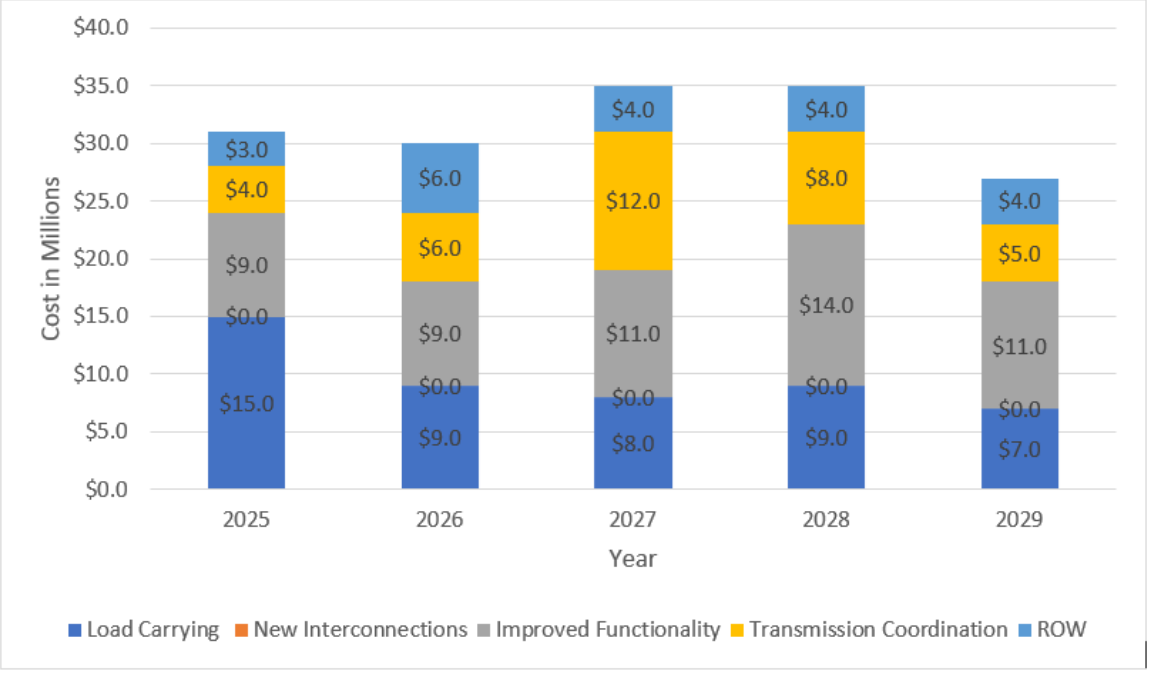
HVD 5-Year Investment Plan

The Company's investment plan is projected to cost $140 million over the next five years.

The 5-year investment plan (shown below in Figure 114) will ensure that the HVD system has the capacity to accommodate peak system load including potential changes to load profiles needed for new and changing technologies, maintain safety and reliability, and accommodate interconnection to the system.

Figure 114

HVD LOAD GROWTH AND INTERCONNECTION 5-YEAR INVESTMENT PLAN



***NOTE:** New Interconnections is listed above as $0 and not listed in the unit table below because the projects expected in 2025-2029 in that category will be 100% reimbursed. Also, ROW projects are not listed in the unit table below as these projects vary in scope/size/timing such that units are not readily available

Year	Load Carrying Projects	Improved Functionality Projects	Transmission Coordination Projects
2025	4	18	11
2026	4	14	8
2027	3	15	12
2028	3	15	8
2029	3	15	8

Additional Topics

Streetlighting

What Streetlights Do

Streetlights provide illumination to enhance safety and the aesthetics of roadways, residential areas, and cityscapes in various applications throughout the Company's service territory. The Company operates and maintains all Company-owned lighting.

Quantity and Technology of Streetlights in Service Territory

Consumers Energy owns and maintains approximately 173,000 streetlights. Most of these streetlights are cobrahead fixtures (see Figure 115 below for streetlight fixture count). Cobrahead, Center Suspension, and Post Top fixture examples are shown in Figure 116.

FIGURE 115

STREETLIGHT FIXTURE COUNT

Fixture Type	Count
Cobrahead	119,000
Post-Top	43,000
Center Suspension	11,000
TOTAL	**173,000**

Figure 116

EXAMPLES OF STREETLIGHTS

Cobrahead Streetlight Fixture



Center Suspension Fixture



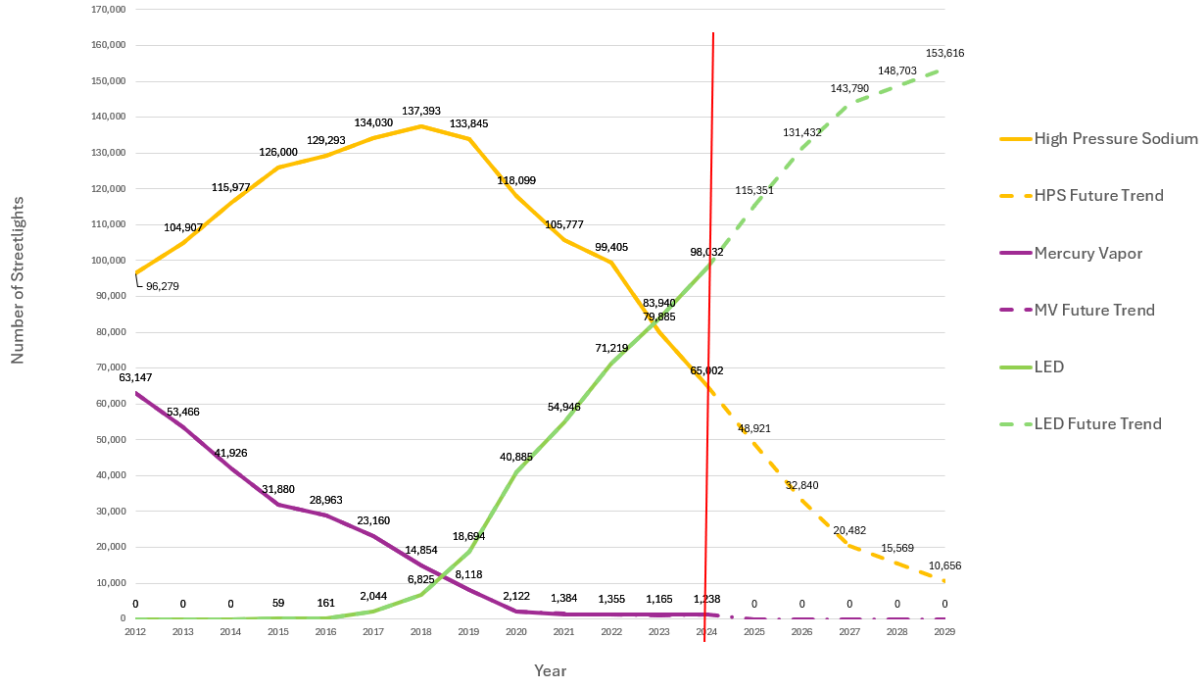
Post-Top Fixture



The Company's streetlighting portfolio includes three types of fixtures: *High Pressure Sodium, Mercury Vapor,* and *Light Emitting Diode* technology.

Figure 117 below represents historical and projected technology trends. The trends reflect the Company's transition from *High Pressure Sodium* fixtures to *Light Emitting Diode* fixtures due to the increase in efficiency.

FIGURE 117
Streetlight Technology Trend



Lifecycle Analysis

The shortest lifecycle component of a streetlight is the *lamp*, which drives the useful life of a streetlight.

- Lamps on the high intensity discharge ("HID") fixtures are rated for 24,000 hours of service.
- With approximately 4,200 hours of lighting service annually, the average life of the lamps in HID fixtures is approximately six years.
- Newer lighting technology light emitting diode ("LED") fixtures are more efficient and are rated for 84,000 hours of service bringing the average life of a LED fixture to 20 years.

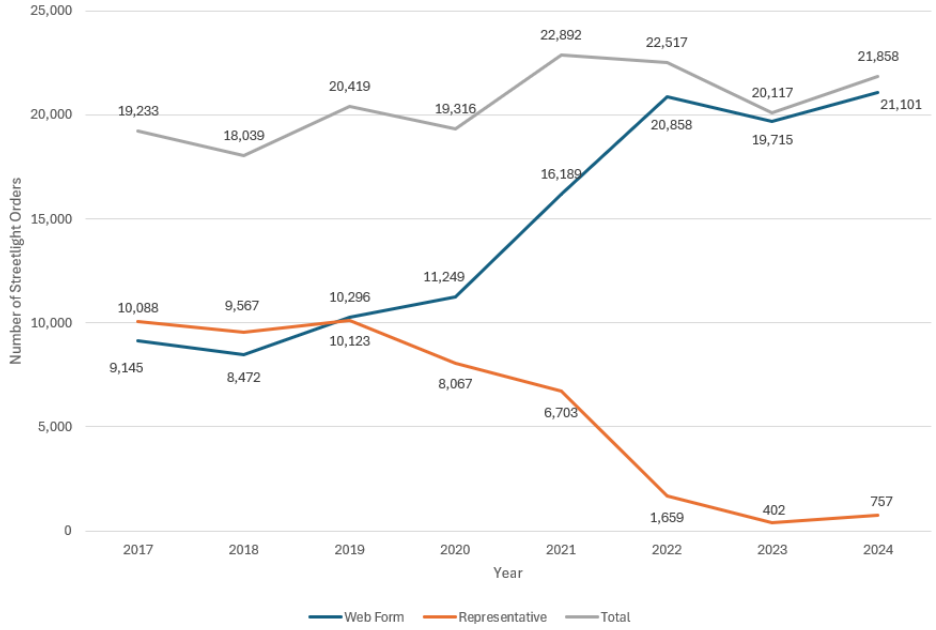
Streetlight Asset Health and Risks

As shown in Figure 118 below, approximately 22,000 streetlight outages and issues are reported each year.

- Non-third party related primary causes of streetlight outages are attributed to bulb failures.

FIGURE 118

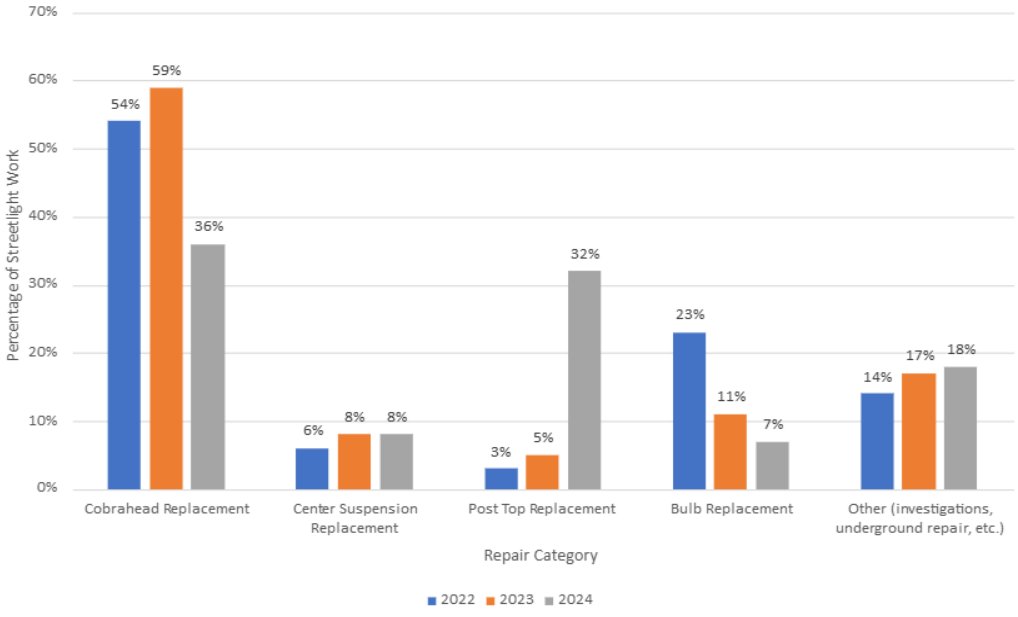
Streetlight Orders by Creation Type



A breakdown of *work type* is shown in Figure 119 below.

FIGURE 119

WORK TYPE BREAKDOWN OF STREETLIGHT ORDERS



Workplan

The ideal state for the Company's Streetlighting program is to repair or replace streetlights only at the end of the component lifecycle. Extending the lifecycle of the luminaire reduces repair expenses across the Company's streetlight portfolio.

LED Conversion of HID lamps across all applications reduces the frequency of bulb-related outages.

To facilitate this, cobrahead, center suspension, and post-top HID installations are being converted to LED technology upon failure.

In addition, vicinity conversion tactics will be used for Cobrahead and Post-Top installations. Vicinity conversions upgrade in-service HID lighting in the vicinity of a failed luminaire, and this reduces costs per conversion by reducing frequency of repair worker mobilization to the same area.

Streetlight 5-Year Investment Plan

The Company will complete vicinity conversions across cobrahead and post top lighting types.

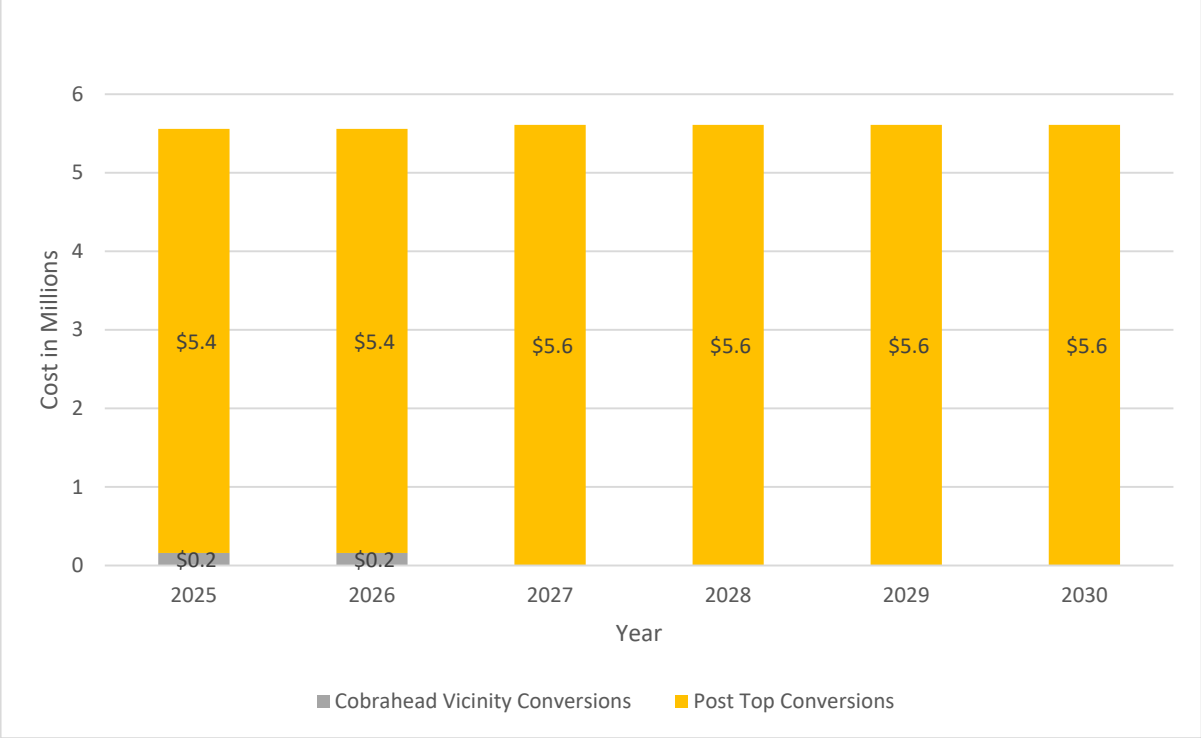
- The Company estimates 11,100 HID cobrahead lights will be converted to LED technology through reactive conversion and 260 HID cobrahead lights will be converted to LED technology through vicinity conversion, annually.
- The Company estimates all Cobrahead fixtures will be converted to LED technology near the middle of 2027. This plan will cost $0.4 million over two years.
- The Company estimates 3,910 HID post top lights will be converted to LED technology through reactive conversion and 800 HID post top lights will be converted to LED technology through vicinity conversion, annually.
- The Company estimates all post top fixtures will be converted to LED technology by mid-2033. This plan will cost $47.5 million over the next nine years.
- Post top vicinity conversions will increase to 1,000 annually once all cobrahead lights are converted to LED technology.

Failure costs of streetlight assets are expected to be reduced following the completion of LED conversions. The 5-year investment plan for streetlighting is shown below in Figure 119.

Figure 1219 includes vicinity conversion of cobrahead streetlights, reactive conversion of post top streetlights (began in 2024), and vicinity conversion of post top streetlights.

Figure 119

STREETLIGHTING INVESTMENT PLAN



Year	Cobrahead Vicinity Conversions	Post Top Conversions
2025	260	4,710
2026	260	4,710
2027	0	4,910
2028	0	4,910
2029	0	4,910
2030	0	4,910

Grid Automation

Grid Automation (formerly "Grid Modernization") operationalizes proven technology to enable a reliable, resilient and automated electric grid that is secure and affordable for customers. Grid Automation delivers for the future grid by **incorporating new technologies and applications into the electric system to increase reliability**; **optimizing energy delivery**; and facilitating the **optimal use of DERs**.

While many utilities share common themes for defining Grid Automation, every utility has a unique approach for implementing and enabling Grid Automation capabilities due to their unique customer, geographical, operational, regulatory, and business needs.

- Grid Automation plans include **standardization and deployment of new proven technology** in substations and on electric lines.
- Also included is the **development of new tools and systems** to improve the way the Company monitors, controls, and optimizes assets.

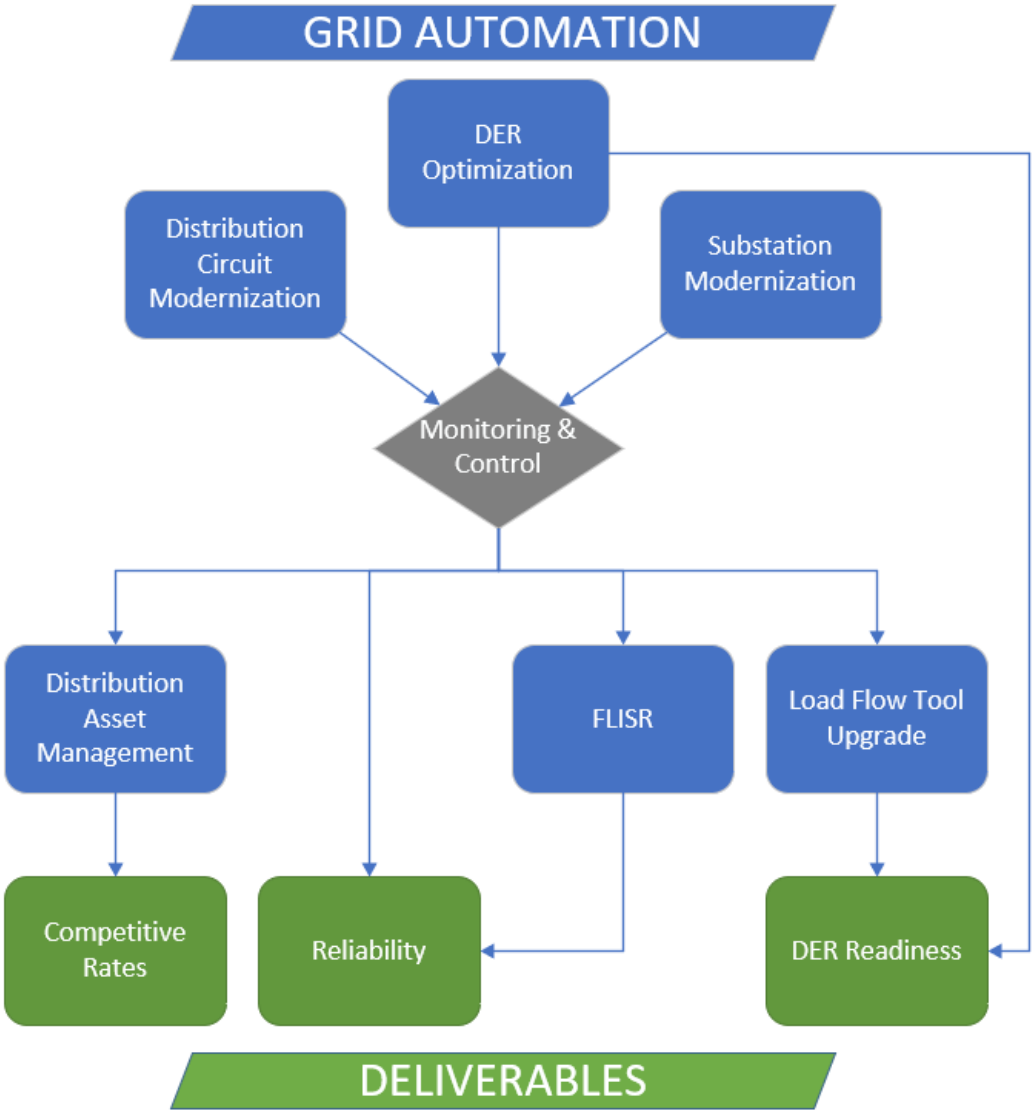
The Company continues to invest in new technologies and digital tools to build for the future through research, testing, and development of modern grid technologies that support key Company objectives.

To support enabling these capabilities and the overall Reliability Roadmap, the Company's Grid Automation organization is planning to develop a Grid Automation 5-year Strategy. This will inform future rate cases and needed investments by benchmarking the industry to help sequence new technology in a way that provides optimized benefit for customers.

As seen in Figure 120 below, the foundational technologies of Grid Automation enable monitoring and control of the distribution system. With increasingly wider monitoring and control, several other key Grid Automation systems gain connectivity to the grid, which is needed to deliver further benefits beyond the sum of the foundational technologies' parts.

All these initiatives significantly affect key Company deliverables such as reliability, competitive rates, and DER readiness.

Figure 120
Grid Automation Deliverable Mapping



New technologies are run through a robust *Technology Enablement Process* ("TEP") (see Figure 128 below) to ensure all facets of the technology solution are ready for use by Company stakeholders when the solution has reached go-live.

Figure 121
High-Level Technology Enablement Process



Distribution Circuit and Substation Modernization

There are many opportunities to improve substations and distribution lines to be ready to support the needs of the future grid. Therefore, Grid Automation continues to participate in utility research projects and innovation forums to understand utility best practices and identify the best technology approach for the distribution system.

- As **new LVD technologies** are shown to provide utility value, the Company considers including them within the strategic **Distribution Circuit Modernization ("DCM") roadmap,** a long-term plan to enable new technologies that build on the learnings and capabilities of others in the DCM roadmap. The DCM roadmap is a living document that evolves based on those learnings, as well as align with utility industry best practices and research.
- Similarly, the **Substation Modernization** program maintains a strategic substation technology roadmap with a vision to advance substation infrastructure to the next generation, including IP-enabled networking capabilities. Substation Modernization initiatives will also follow the *Technology Enablement Process* and build out progressively beneficial and interdependent substation systems and devices.

The technologies being pursued on these roadmaps are foundational to support general monitoring and control of distribution circuits and substations, and set the stage for future more complicated automation via ADMS, FLISR, and DER Optimization.

Distribution Energy Resources Optimization

The Company has launched an initiative to standardize and prepare the grid for the anticipated growth of DER, as discussed earlier in the Non-Load Challenges from Customer Technology Adoption section.

The DER Optimization initiative consists of a variety of hardware and software deployment projects to develop, evaluate, and standardize DER management capabilities across the spectrum of DER types.

- Projects will be sequenced so that initial deployments focus on grid-edge capabilities that include DER gateways.
- DER gateways optimize controllable resources based on local conditions, as well as provide communications and translation services to a diverse set of DERs.
- DER gateway projects on the grid-edge include solar arrays, batteries, EV chargers, and circuit-level deployments.
- As DER penetration increases, the Company plans to deploy a centralized DER management system (DERMS) that will provide system-level grid benefits such as peak shaving, market participation and compliance with FERC Order No. 2222.
- A centralized DERMS is critical for managing bi-directional power flows, power quality concerns, and interconnections with third party DER.

- High levels of DER penetration may negatively impact reliability, efficiency, and overall grid performance if not properly monitored and managed.
- The increase of the Distributed Generation program cap from 1% to 10% of the utility's average five-year in state peak load introduced by Public Act 235 escalates the reliability concern and accelerates the timeline for needing to begin DERMS implementation.

The DER optimization initiative will not only mitigate these threats but will lead to future reliability and efficiency improvements. **DER benefits can only be fully realized when they are comprehensively integrated into grid operations.** Therefore, DER must be visible to and controllable by the Company's grid operators to ensure reliable, affordable, and safe electric service.

Distribution Asset Management ("DistAM")

DistAM is the application of **asset management principles and processes to electric distribution assets to maximize the usefulness and realization of value over their lifecycle.**

Previous sections covering LVD and HVD assets described current state asset health and management practices. However, the Company is pursuing a centralized and standardized asset management strategy that encompasses all electric assets in a unified approach.

Our DistAM program will enhance existing lifecycle management capabilities by **collecting key asset data (*e.g.*, age, nameplate data, location) to drive a risk-informed, value-based decision-making methodology** to manage and optimize asset investments. This work is aligned with industry best practices defined in ISO 55001, as well as from the *Michigan Infrastructure Council Asset Management Program*.

Asset Management will standardize the Company's asset life-cycle processes, data, and technology, allowing for improved capture, analysis, and visualization of asset health, which will lead to more optimized investment planning scenarios.

The primary benefits of DistAM include:

- Reduced capital and maintenance costs.
- Reduced customer outages and restoration costs
- Reduced power quality issues and system losses
- Increased asset availability and deferred capital depreciation
- Reduced asset degradation risk
- Improved resilience of the electric distribution system
- Proactive condition-based asset replacement/maintenance

The DistAM strategy identifies three key components that will deliver a robust asset management system. These components are *Asset Repository*, *Asset Performance Management* ("APM"), and *Asset Investment Planning* ("AIP").

These components will leverage collected distribution asset data into a single centralized database, which provides enhanced integration into asset health performance analysis and investment strategy platforms.

- The Asset Repository software release, with four initial assets, is scheduled for the second quarter of 2025. After the software release, asset data can be added incrementally using the standard integration elements being deployed. The Asset Repository can then ingest asset data from other data collection methods to improve asset data quality.

- The APM software calculates asset health scores and utilizes Asset Repository asset data. With the incremental approach of the Asset Repository, the APM will need to accommodate sparse asset data by possibly augmenting static nameplate data with sensor technology. Exploration of automated sensor readings could provide measurements to the APM to improve asset health calculations.
- The AIP solution is now complete. The integration of additional asset data into the Repository and APM will only improve the benefits of the AIP system.

The Company envisions that as the technology of imagery analytics advances, so too will the benefits of DistAM.

DistAM is an essential part of the Company's broader initiative to maximize reliability and resiliency by optimizing how the electric distribution system is proactively maintained and managed.

Realizing the benefits of these assets requires effective management of the electric distribution system, which is the foundation that DistAM provides.

Reliability Analytics Monitoring Program (RAMP) *(formerly Anomaly Detection Analytics)*

The RAMP uses **line sensor data across our LVD and HVD systems to understand whether we are experiencing conditions** (asset deterioration, tree branch interference, etc.) **on our lines that are likely to cause an outage** such as asset deterioration and tree branch interference**.**

These analytics provide an opportunity to send crews to complete work to mitigate these conditions proactively at a lower cost to rate payers as opposed to addressing these in an emergent condition after the outage has occurred.

In 2023, more than 500,000 customer outage minutes were avoided by correcting outages before they happened.

The Company is pursuing a contract to maintain this service into 2025 and beyond. Over the next five years this project is expected to save 1 minute of SAIDI.

Load Flow Tool Upgrade

For nearly 25 years, various planning departments throughout the Company have relied on an industry-standard suite of CYME power engineering software products to assess the current and future health of the distribution system.

The modeling techniques and simulation capabilities enabled within these tools have met the planning requirements of a system with traditionally predictable load and short-circuit conditions but cannot accurately or efficiently capture the time-based complexities introduced by DERs and electrification. See the Challenges from Customer Technology Adoption, and Non-Load Challenges from Customer Technology Adoption sections for further discussion on these challenges.

To begin to address these challenges in planning tools, the Company entered the discovery phase of a Load Flow Tool Upgrade project in 2024, with plans to start developing and enabling advanced forecasting, modeling and simulation capabilities in 2025.

- At a high-level, this initiative will evolve our planning models from a snapshot in time approximation of peak conditions to a digital twin representation of the distribution system capable of identifying system constraints and opportunities for optimization at any hour of the year, under various customer technology adoption, weather, and load growth scenarios.

Planning tool enhancements will allow the Company to make the right infrastructure investment decisions at the right time to maintain the reliability, power quality, and efficiency of the distribution system as customer adoption of new technologies increases. They will also:

- Enable comprehensive review of the fast track and supplemental screens specified in R 460.946 and R 460.950 of the Michigan Interconnection and Distributed Generation Standards
- Increase the accuracy and value of the Company's hosting capacity maps
- Support Company compliance with the various distribution system impact analyses and data reporting requirements of the Michigan Transportation Electrification Plan
- Provide planning and interconnection SMEs with the insights needed to successfully navigate the increased Distributed Generation program cap required by Public Act 235.

Fault Location Isolation Service Restoration (FLISR)

The Company worked with EPRI in 2024 to develop a plan for full implementation of FLISR. FLISR consists of both hardware and software.

The hardware consists of communicating reclosers, switches, and line sensors. The Company has made significant progress with the installation of these reclosers and line sensors, and even more potential awaits with the DCM technologies described above including SCADA-enabled reclosers and switches.

The next area of focus in the Company's sequence is to use SCADA controlled switches to further sectionalize circuits, to limit outage impact to customers.

- Within the ADMS software, FLISR will use the communicating reclosers, switches, and line sensors to automatically identify where faults are on the system.
- FLISR can provide automatic functionality to isolate faults before analyzing load transfer potential for the remaining de-energized customers downstream of the faulted section. Additionally, it decreases the public safety risk of encountering energized downed wires. Patrol times and switching times for field crews are also greatly reduced.
- To enable this, updates and enhancements will be required to the ADMS software and to core applications that support ADMS, such as Distribution Power Flow, Substation Model integration, Spectra Insight and a simulation environment for Grid Operators to learn necessary skills before executing on the job.

By 2025, the Company will have deployed more than 12,000 line sensors across HVD and LVD.

These sensors provide optimal coverage of the grid to support the FLISR program. Line sensors are **devices that attach to primary lines to monitor current and faults, as shown in Figure 122.** They detect faults and determine a probable location of an event, making them critical in enabling FLISR.

Line sensors also provide information such as loading, phase balance, momentary outages, line disturbances, and other alarms.

- Line sensors can be used to improve the LVD planning process by providing more accurate load flow modeling. This more precise and real-time load information can be used to improve the load transfer process both for planned and unscheduled outages.
- This tool reduces the duration of the manual load transfer writing process and improve the accuracy of the modeled transfers.

FIGURE 122

3-PHASE LINE SENSOR INSTALLATION



Weather Monitoring

Given the increasingly severe weather Michigan is experiencing, the Company needs the ability to monitor the weather at a localized level.

The current coverage of existing NOAA weather stations leave gaps in the Company's service territory. **To address this, the Company intends to install modern weather stations in 2025/2026 across its service territory.**

The number of weather stations is expected to expand through 2027, providing visibility across the service territory including wildfire risk areas. This will allow for quicker decision-making capabilities to aid in storm preparation and response. This includes repositioning Electric Line Crews to areas that are in a storm path and deploying Damage Assessment teams to survey areas that indicate severe weather based on the weather station real-time data.

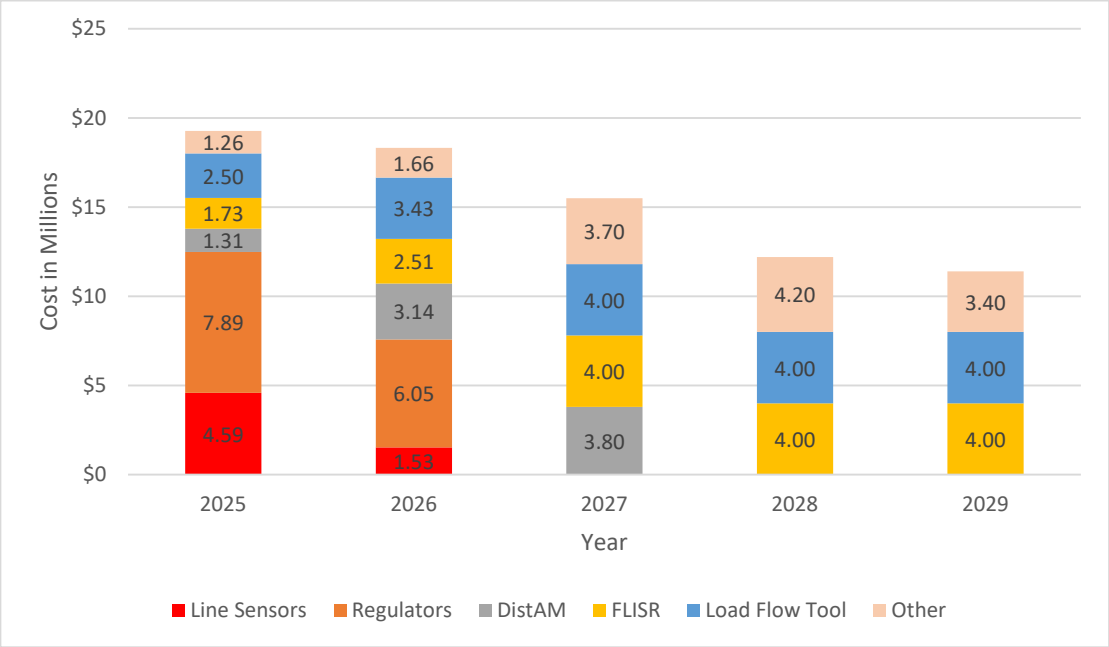
Additionally, the Company will study these localized weather impacts against the performance of the electric assets, informing future resiliency investments. The Company plans to expand the number of weather stations throughout 2027.

Grid Automation 5-Year Investment Plan

Over the next five years, the Company will invest in the automation and modernization of the electric grid through various hardware and foundational software deployments.

This includes deployments of remote-communicating grid equipment such as Line Sensors, Voltage Regulators and Switches. It also includes foundational software deployments such as DistAM and FLISR that prepare the grid for the future.

Figure 123
Grid Automation 5-Year Investment Plan



Year	Line Sensors	Regulators
2025	750	221
2026	250	169
2027	0	0
2028	0	0
2029	0	0

Advanced Distribution Management System (ADMS)

ADMS is the **software platform that supports the full suite of distribution management and outage management** systems.

This platform brings together the Company's Distribution Management System ("DMS"), its Field Mapping Applications, and its Electra Outage Management System ("OMS")—which includes additional outage applications (tools that integrate with ADMS and aggregate outage-related information).

ADMS is dependent on the following:

- Supervisory Control and Data Acquisition or SCADA, as described in the Substations section.
- Geographic Information System ("GIS")
- Advanced Metering Infrastructure or AMI—a two-way communication system that collects detailed metering information throughout the Company's service territory.

ADMS real-time functionality drives improved decisions to make the electric distribution grid more efficient, enabling the Company to get customers' lights on faster.

There are two main enhancements to the ADMS platform planned, along with continued integration improvements with additional outage applications, including:

1. Implementation of the Field Mapping Application
2. Completion of the DMS platform to include:
    a. Fault Location Isolation & Service Restoration ("FLISR")
    b. Switching Order Management ("SOM")

The **Field Mapping Application** will extend the use of ADMS core functionality to the Company's field workforce.

This Application **will improve workforce efficiency by providing field employee precise real-time circuit maps and damage assessment information**.

Real-time damage assessment—when combined with 2024 implementation of Live Wire Down—will **improve customer experience** through the Company's current online outage map while also improving public safety through reduced restoration times.

Completing the *DMS* portion of ADMS will add enhancements focused on implementing all FLISR and SOM software modules. FLISR was described earlier in the Grid Automation section of this document.

- **SOM** is an ADMS **application that generates switching orders for field workers**, which will send automatic control signals via SCADA to perform and verify automatic switching operations. Using point-and-click interaction with graphical applications, a switch order is established and validated against real-time operating conditions via network interface (allowing pre-verification of the order before it is dispatched, saving time in outage response).

In addition to the two primary enhancements, the Company expects to **improve system Reliability and Resiliency through use of automation and digital tools to support ADMS.** Better integration of outage applications not currently incorporated into the Electra OMS or DMS will better integrate real-time data for restoration.

Aside from Reliability benefits, the Company will be less at-risk from catastrophic system failure.

FIGURE 124

ADMS COST and SAIDI

ADMS Enhancement	2023 Capital	2024 Capital	2025 Capital	SAIDI Savings (excluding MEDs)
OMS Electra incl Live Wire Down	$800k	$900k	$0	5 minutes
Field Mapping Application	$0	$1,600k	$0	4 minutes
DMS complete FLISR and SOM				
Outage Applications Integration	$250k	$250k	$0	4 minutes
AMI Automation Use Case	$150k	$0	$0	2 minutes
Total	**$1,200k**	**$2,750k**	**$0**	**15 minutes**

Next Digital Investments

Integrating emerging technologies, data, and analytics for Consumers Energy is instrumental in achieving our Company goals with great precision and foresight.

Our Next Digital Investment strategies provide valuable insights enabling **data-driven decision-making leading to enhanced efficiency, improvement to risk management, and cost reductions**—all to ensure our business remains resilient and reliable in a rapidly evolving digital landscape.

Additionally, using emerging technologies helps provide actional insights to tailor our tools and services to meet customer demands effectively.

By leveraging the next digital investments such as artificial intelligence, machine learning, and automation, we can **optimize processes, identify trends, and improve customer experiences**.

Outage Forecasting Model

Through a partnership with the University of Michigan, the Company is pursuing creating a suite of outage forecasting models. These models will predict customers without power, estimated incidents/trouble spots, wire downs, and poles that require replacement over the upcoming six-day period.

Asset, outage, damage, and weather data will be combined to inform the models and the output will be used to make informed decisions regarding pre-staging and staffing for weather events.

- Models for estimated incidents, damaged poles, and the number of wire downs will be delivered in the second quarter of 2025.

The customers without power model will be delivered in the fourth quarter of 2025.

Productivity & Utilization Analytics (Formerly the Restoration Wait Time Tracker)

In 2023, the Company established a dedicated group to address restoration costs. As a precursor to the Restoration Wait Time Tracker (a tool that will **provide the ability for storm response teams to understand in real-time what is happening in the field** during restoration activities),

- Productivity and Utilization Analytics have been created to measure effectiveness of restoration during storm events in 2024.
- **Work orders, crews, hazards, and outages were combined to provide visibility into the productivity differences between internal crews and contractor crews.** In 2024, post-storm analyses were standardized and real-time capabilities will begin construction in 2025.

Our storm response teams can then see in real-time when and where delays are occurring and take action to resolve barriers. This will lead to faster storm restoration.

This project is expected to result in 0.5 minutes of SAIDI savings and a 12% productivity increase during storm restoration activities.

Catastrophic Crewing Replacement

Catastrophic Crewing (“CatCrew”) is the Company’s 15-year-old home-grown resource management software tool used during storm restoration.

- This tool captures information about who is engaged in storm restoration, the Headquarters they are working from, and their work and rest time periods.
- CatCrew also captures lodging and food requirements needed for resources engaged in storm response.

The CatCrew tool **enables the Company to have a clear and up-to-date picture of resource capacity and engagement**, ultimately leading to a more efficient and faster restoration.

After restoration work is complete, we use the data captured within CatCrew to perform advanced analytics and identify improvement opportunities.

We are pursuing a vendor-provided software product to replace CatCrew due to our current software becoming outdated and difficult to maintain. The procurement of internal and external resources during storm restoration can be a prolonged process and **replacing the current software with a more responsive system will allow us to realize efficiencies** in procuring needed resources.

- Vendor-provided products exist with the functionality we need, including integration with hotels and food providers.
- The Company is in the beginning stages of the Request for Proposal ("RFP") process and estimates this will run through 2023, with selection occurring in first quarter 2024.
- The Company plans to have a new software solution implemented in 2025.

Forestry Workplan Intelligence & Strategy Engine ("WISE") Phase 2

As discussed in the *Forestry Line Clearing Program* section, the Company is working to enhance its use of advanced technology in this space.

In 2025, an internal team will be updating the Forestry WISE model to provide the annual LVD full circuit clearing workplan at the LCP-level. Once completed, this will enable the Company to be more strategic in forestry work selection, driving the replacement of reactive analysis with predictive analysis.

Imagery Analytics

The Company will re-imagine the inspection process across the various energies, **using drones and other image capture technology in a much more intentional manner, while investing in automation and machine learning** to increase the efficiency with which defects are identified.

- Currently, the Company performs cycle-based inspections on its Electric System through manual processes that require employees to physically walk or drive the system to perform a visual inspection, take photos, and manually document and classify their findings.
- Through investments in automation and machine learning, the Company can achieve Full System Inspection, including 360-degree views of assets created through automated image collection by various methods (drone, helicopter, robotics, video cameras, etc.) and trained machine learning models that identify and analyze assets to target reliability improvements.

For example, as mentioned above in the HVD Lines section, the Company is using artificial intelligence software and machine learning to automate the review of video from the annual helicopter inspection to identify specific locations of vintage insulators, which are the largest contributor to customer outage minutes on the HVD system on average over the last 5 years.

In 2025, the Company will create a single repository for images to be leveraged for forestry, asset & defect identification, and wildfire use cases. The Company will also purchase four autonomous drones and work to secure an FAA line of sight restriction waiver so that the drones will be able to complete autonomous missions within a defined five-mile radius.

Maintaining Digital Assets

Equally as important as investments in new digital capabilities is the ability to properly maintain technology assets after implementation—including the underlying foundational infrastructure, systems and platforms in the Company's digital landscape.

Prudent technology asset management and replacement programs, system monitoring, timely upgrades, and continuous system patching to mitigate cyber threats are required to sustain stability, support, and security of existing systems that directly and indirectly drive electric reliability.

Technology and Analytics Investment Plan

The plan for Next Digital Investments will cost $14 million over the next three years.

See Figure 125 below for the Next Digital Investments plan.

Figure 125
NEXT DIGITAL 3-YEAR INVESTMENT PLAN



Economic Development and "Mega-sites"

In June 2023, EPRI published a prospectus *The Impact of Industrial Onshoring on Electric Sector Demand Growth*, assessing the impacts of industrial onshoring and more recently the increase in data centers across the nation, both representing opportunities for the Company and State of Michigan to partner to win major industrial projects and boost the state's economy.

Business sectors and individual organizations continue to factor supply chain risks into strategic positioning and operational decision-making. Similarly, the U.S. government has been investing unprecedented sums in domestic manufacturing, infrastructure, and decarbonization to improve national security and create jobs.

In 2024, the Site Selectors Guild, in partnership with Development Counsellors International, published their *State of Site Selection* report and highlighted that these U.S. programs have resulted in construction spending on new manufacturing facilities, more than doubling from 2022 to 2023 in such industries as data centers, electric vehicles, battery plants, and semiconductors.

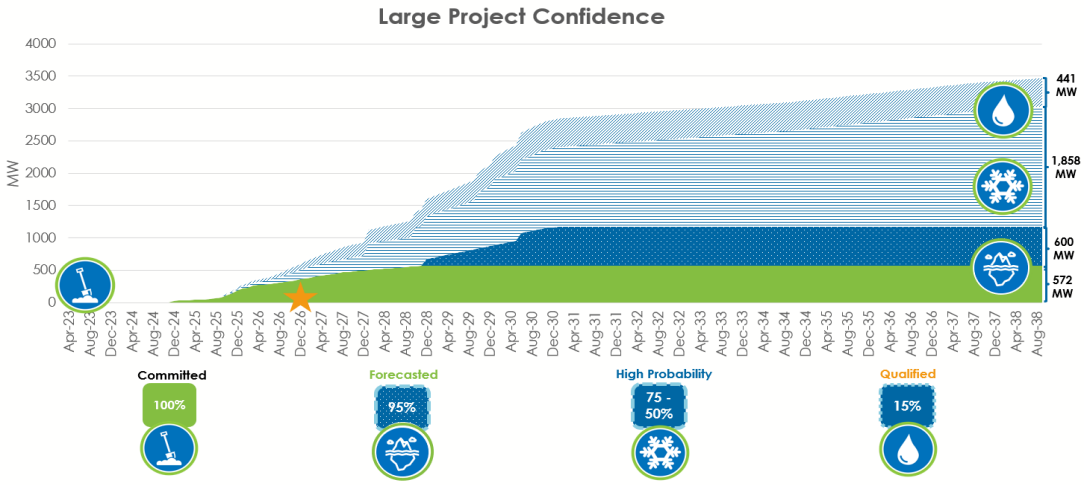
These events have created new conditions and opportunities for states to coordinate with utilities to address the complex needs associated with securing these projects. In the *State of Site Selection,* **electric power capacity is rated a 4.7 out of 5 point scale of having a significant impact on industrial project location decisions**. Of site consultants surveyed, 98% were in agreement that electric power capacity will significantly impact the future of industrial projects.

New manufacturing plants can generate significant local impact by adding large blocks of load. Serving new demand creates the need for new approaches to load as well as coordinated planning and development of grid infrastructure. This is because the demand growth created by industrial onshoring can have disruptive impact at local levels.

Figure 126 below shows the load projected to be added to the system as part of large projects greater than 35 megawatts ("MW").

Figure 126

ECONOMIC DEVELOPMENT LARGE PROJECT MW PROJECTIONS



Industrial reshoring continues to create demand growth in the Company's service territory, which is poised to play an outsized role in the EV battery industry, due to its proximity to existing American auto manufacturing plants.

Data centers also represent a growing sector across the nation, with many areas already seeing an unprecedented number of requests for large amounts of demand.

Currently, the Company has over 40 leads and opportunities, totaling more than 14,800 MW of potential load related to data centers alone. This potential load is not represented in the graph above. In the *State of Site Selection* report it was quoted from the Boston Consulting Group that data center electricity consumption was 2.5 percent of the U.S. total in 2022, and is expected to triple by 2030.

- To win these major projects, **increased coordination among the Company as well as manufacturers, system operators, development agencies, regulators, and other stakeholders is essential** to ensuring significant new demand can be met efficiently and in a timely fashion.

Workplan

The Company regularly works with the *Michigan Economic Development Corporation* ("MEDC") and other local economic development groups competing for prospective new large industrial customer facilities that are considering establishing a site in Michigan.

- We provide competitive electric service proposals as part of a broader Michigan response to RFPs.
- Many of these RFPs are very competitive in nature, and consider sites across North America, including considering if a site is ready and able to meet customer project timelines.

These RFP response efforts benefit the broader economy of the state of Michigan when a Michigan site is selected as the final location.

Large new customer connections and load additions provide the benefits of job creation, plus other state and local government revenue streams associated with business expansion.

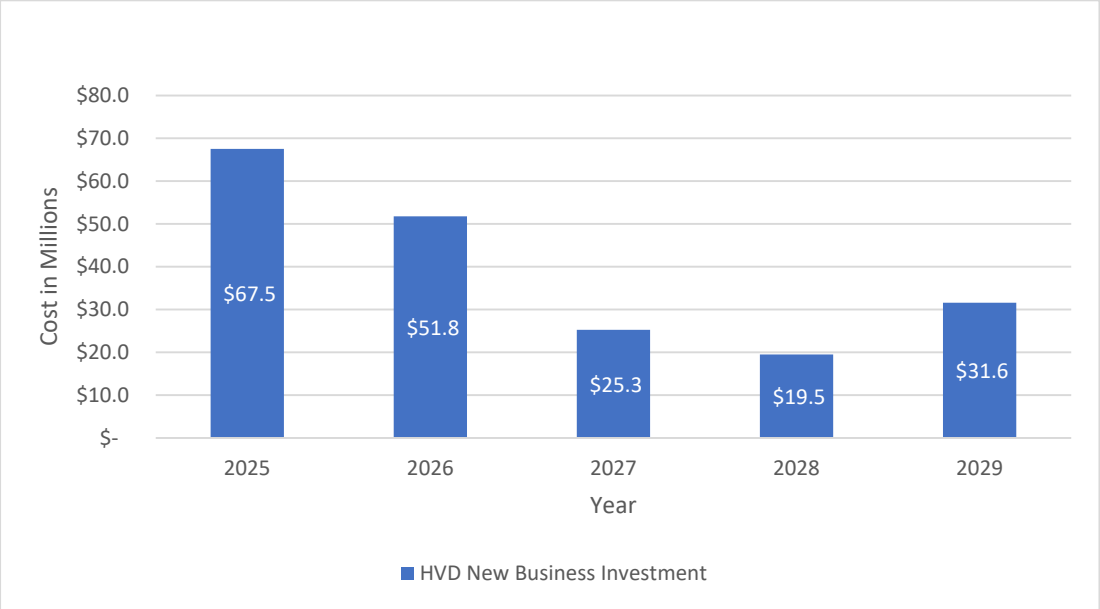
However, the Company has learned that the lead time to install a large, new dedicated customer substation and the associated lines are often prohibitive for potential customers, who are looking for "shovel-ready" sites where they can start production as soon as possible.

- The Company is pursuing a solution for such a situation in advance by standardizing our design and equipment and pre-purchasing long lead-time equipment.
- This will reduce the time needed to provide electric solutions for potential customers, and create an advantageous position to attract large, transformational, and new business opportunities to the state of Michigan.

Figure 127 below represents the planned investment needed to support known and planned projects and potential projects that are known but not yet committed.

Figure 127

NEW BUSINESS PLANNED INVESTMENT



Hosting Capacity Analysis

Hosting capacity **is defined as "the amount of distributed energy resources ("DERs") that can be accommodated without adversely impacting operational criteria**, such as power quality, reliability, and safety, under existing grid control and operations and without requiring infrastructure upgrades."[14]

The Company interconnects DERs to its distribution system through an MPSC-regulated interconnection process. When a proposed DER goes through this process, the Company performs a resource-specific analysis to ensure that the resource will not cause any reliability or capacity issues, and to identify any necessary system upgrades. The analysis can range significantly in complexity based on the size of the proposed DER.

A *hosting capacity analysis* ("HCA") can improve and streamline this process by identifying locations on the system with a high probability of accommodating DERs. While resource-specific analyses are still required with an HCA, an HCA can help customers and DER developers avoid proposing interconnections and incurring study costs in areas that are not suitable for DERs.

In 2020, the MPSC directed the Company to pursue a 'phased' approach to developing HCAs, with two primary phases:

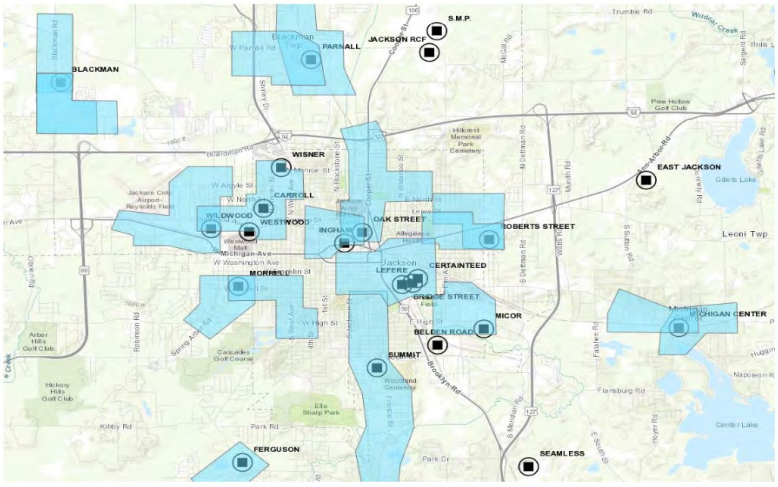
Phase I: A base-level approach with a zonal go/no-go map

Phase II: Specific, detailed analyses on areas of the distribution system with high DER penetration, incorporating this information into a more detailed map with circuit voltage-level information as DER penetration continues to increase.

The Company completed the Phase I analysis and reported the initial results in its 2021 EDIIP filing, with a detailed description of Phase I methodology. Since that time, the Company has updated its Phase I analysis as system conditions have changed, and the Company maintains a publicly available updated version on its website:
https://cms.maps.arcgis.com/apps/instant/lookup/index.html?appid=b90ff63b338043b7bcae43dd685a419d

Phase I hosting capacity analysis shows circuits, in polygon form, that have at least 2 MW of hosting capacity, and result in maps such as this:

Figure 128
EXAMPLE OF PHASE I HCA MAP



[14] August 20, 2020 Order in Case No. U-20147

The Company's 2021 EDIIP also committed the Company to move ahead with a Phase II analysis.

To date, the Company has still not seen areas of high DER penetration on its system that would trigger the specific, detailed circuit analysis as originally contemplated when the 2021 EDIIP was filed. However, the Company expects to have a Phase II analysis available by the second half of 2025.

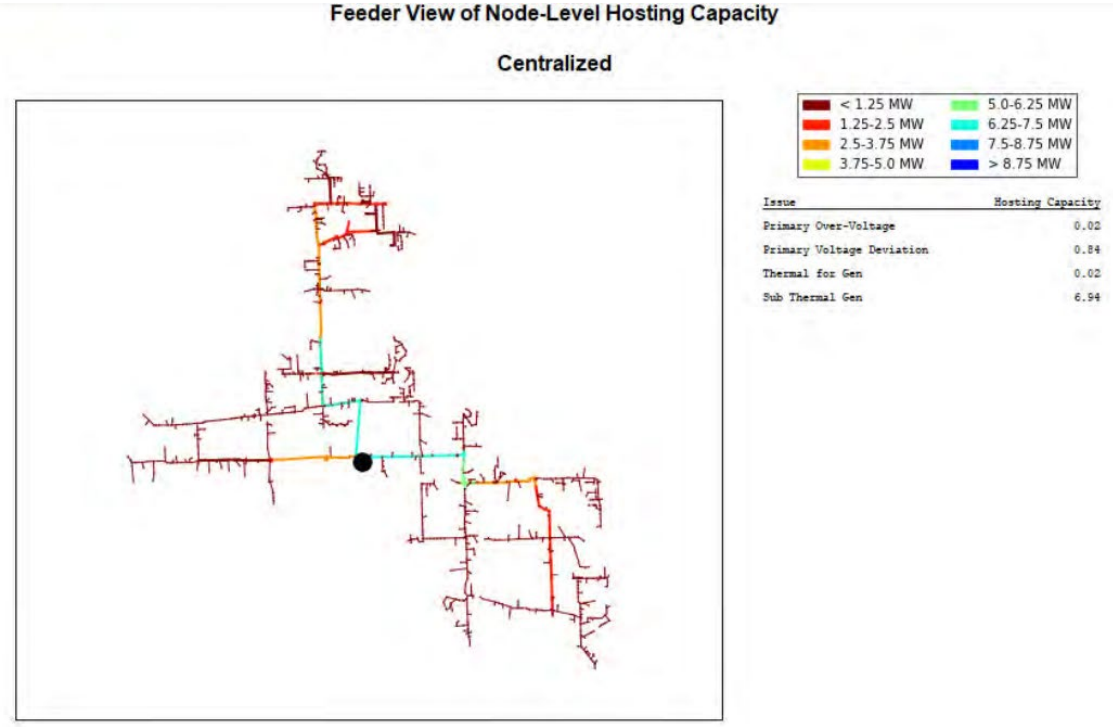
For its Phase II analysis, the Company will be able to use maximum load data from 2024 to create a snapshot of detailed hosting capacity information. This analysis relies on the Distribution Resource Integration and Value Estimation ("DRIVE") tool developed by EPRI, and also on the Company's CYME planning models.

Because manual analysis is still required with current capabilities, Phase II maps will be detailed but will not be updated in real time.

Phase II hosting capacity maps will show much more detailed circuit information, as follows:

Figure 129

ILLUSTRATIVE PHASE II HCA MAP – CIRCUIT LEVEL DETAIL



Going beyond periodic updates to Phase II maps will require the Company to complete the Load Flow Tool Upgrade proposed in its Grid Automation plan.

- The Load Flow Tool Upgrade will bring increased automation to the Company's CYME software, and will explore the use of EPRI DRIVE or CYME's Integrative Capacity Analysis module (ICA) for future hosting capacity analyses.
- The Load Flow Tool Upgrade will introduce time-series simulation capabilities in CYME, and will automate the modeling of existing and queued generation and load in the CYME network model. **This would enable a Phase III** of hosting capacity analysis, with much closer to real-time updates of the available maps.

Resources

Workforce

Field resources are an essential component for the successful continued investment into the electric distribution system. Resources both internal to the Company and externally contracted are staffed to match the work demand.

- The Company uses a **long-range resource planning process** to build workforce plans through a cross-functional planning methodology and deliver an optimally sized workforce that meets the Company's long-term needs.
- **This process reviews and aligns with a one-to-five-year resource plan**, factoring in demand, resource requirements, and resource availability to bring visibility to gaps and develop actions and scenarios to close them.
- The team leading the process **engages with Executive Leadership quarterly** to adjust resource plans and ensure resource adequacy.

This collaborative resource planning process works across the Electric Distribution organization to make informed decisions about the Company's electric field resources. The multi-year view ensures resource decisions are made with sufficient lead time to recruit, hire, and prepare Company field resources and external workforces for the work required.

The Company's field resource growth over the last five years has been deliberate to match the forecasted work demand and resource requirements for future years identified through the resource planning process.

This growth was due primarily to acquiring LVD field resources through apprenticeship hiring. These resources have been complemented during peak work demand months with a contractor workforce and have successfully met the work demand within each year.

Historical actuals below only include Company field resources over the last 5 years. This does not represent the entire workforce that was needed to deliver the work.

Figure 130

ELECTRIC DISTRIBUTION OPERATIONS: HISTORIC FIELD RESOURCE LEVELS (CE)

	2018	2019	2020	2021	2022	2023	2024
Year End Internal Resources	942	1,019	1,034	1,164	1,235	1,326	1,325

Ensuring Resource Adequacy

Using the resource planning process in collaboration with Electric Operations leadership, the upcoming multi-year resource forecast is available for field resources.

Figure 131 indicates the total resources required to meet our ambitious electric distribution investment strategy for 2025 through 2029.

Figure 132

Resources Required

	2025	2026	2027	2028	2029
LVD (including Underground)	1,160	1,547	1,589	1,969	2,000
HVD	496	538	542	494	492
Total Resources	1,656	2,085	2,131	2,463	2,492
Growth Percentage (YOY)		**26%**	**2.2%**	**15.6%**	**1.2%**

The previous 5 years incorporated resource growth with the Company's LVD workforce to meet identified work demand; however, implementing the *Resilient Grid Plan* will require that workforce growth accelerates more rapidly to meet the immediate resiliency investment needs of the grid.

- The increase in resources needed includes efficiency gains and increased productivity through leveraging predictive analytics, job-site reporting, and recruitment of qualified journey line workers.
- The Company supports its widespread LVD overhead system with a small workforce for its extensive mileage and coverage across the state of Michigan. This is executed with an efficient workforce and operations.

Even with this demonstrated efficiency, the scale of work outlined in this plan requires an even more aggressive growth rate to adequately support the planned investments.

Projected resource growth is driven by three main factors:

1. **LVD overhead field resource growth** of apprentices or qualified line workers to support the necessary system investment, which will be balanced with external contractors across peak time periods.
2. **Underground workforce growth** to match the proposed conversion work.

Maintaining a consistent workforce size or planning for growth—both require a reliable pipeline of talent to balance or exceed forecasted attrition.

Therefore, to ensure a talent pipeline for a long-term sustainable workforce, the Company initiated partnerships with strategic community colleges starting in 2008 to host line worker pre-apprenticeship programs.

These programs embody the triple bottom line by providing skilled trade training opportunities to local communities and future employees, investing in communities and their prosperity, and bringing diverse talent to the forefront of leading the clean energy transition.

- The *School to Work* program is one partnership that is currently investing in communities such as Flint, Muskegon, Alpena, Lansing, Grand Rapids, and Jackson, where career opportunities are immensely impactful, and continues to reinvest in the state of Michigan.
- This purposeful effort has yielded great success, as 74% of the Company's apprentice line worker hires have come through its *School to Work* programs since 2014.

Figure 133 and Figure 134 showcase some of these students and their training experiences.

Figure 133

SCHOOL TO WORK STUDENTS: MOTT COMMUNITY COLLEGE (FLINT, MI) & ALPENA COMMUNITY COLLEGE (ALPENA, MI)





Figure 134

Line Worker Pre-Apprenticeship Training: Alpena Community College (Alpena, MI)





The growth requirements of the underground workforce will be met as the Company will promote opportunities to other field resource roles in the Company who would be well-suited for this growing workforce.

The external programs that recruit these entry level roles confirm prerequisite skills for successful energy careers and have an extensive nation-wide pipeline.

To meet the investment into the electric grid that customers need and require, the Company's workforce plans also integrate the following methods to adequately staff for the future work demand, which will balance staffing growth:

- Drive towards increased efficiency in work or optimized scheduling, such as packaging similar work on a common circuit or within a single outage.

- Build work plans with agility to use the right workforce at the right time for the right response, allowing work to be levelized across months or peaks to be supported by contractor workforces.
- Manage workforce plans to inform talent pipeline programs with adequate lead time for apprenticeship training and hiring.

Using these methods will ensure work demand and field resource needs are identified for a minimum of a 5-year forecast. The Company's past successful hiring practices instill confidence that all forecasted resource requirements will be met, and will deliver a diverse and hometown-focused workforce.

Fleet

The Company supports its electric and gas businesses with a fleet that includes over 7,300 owned, leased, and rented units across 36 locations.

These units include light duty vehicles (approximately 2,800 units), medium and heavy-duty trucks (approximately 1,500 units), various types of equipment (approximately 1,400 units), and trailers (approximately 1,900 units).

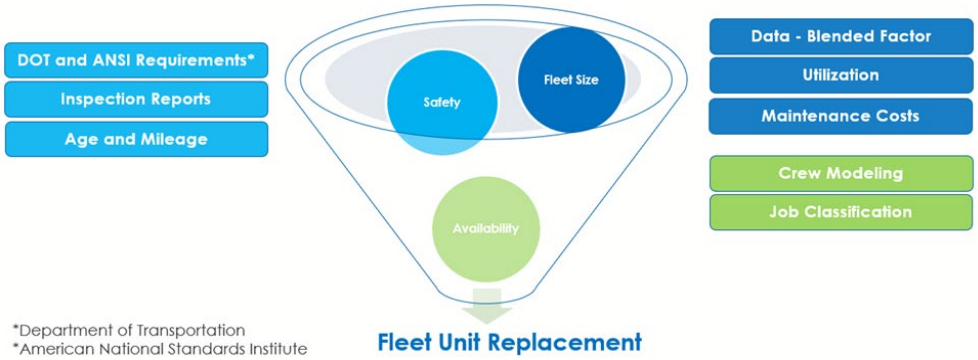
Vehicles are ordered and upfitted to support specific work and are, therefore, specialized for the work they perform; however, the Company does seek ways units can be shared across the business when possible. Some Company fleet units, such as pick-up trucks, vans and sedans support both electric and gas work.

Much of the Company's fleet strategy is focused on its *Fleet Vehicle Capital Replacement Plan*, based on a *Fleet Replacement Planning Process*. This replaces vehicles as they reach the end of their useful life, using a three-phase process:

1. Vehicles are identified as being at the end of life using a tool called the *Blended Factor*, described below in Figure 135.
2. Vehicles identified for potential replacement are further analyzed by considering fleet cost data, crewing data, and fleet utilization data; qualitative inputs like maintenance reports are also considered.
3. Vehicles are confirmed for retirement based on these evaluations, and ordering begins, either through existing contracts or by putting out requests for proposal.

Figure 135

Fleet Capital Replacement Plan Filter



The Blended Factor calculation considers vehicle age, usage, and mileage to identify vehicles nearing end of life, as follows:

Figure 136

Blended Factor Calculation

$$\text{Blended Factor Rating} = \left(\frac{[\text{Age Factor} + \text{Usage Factor}]}{2}\right)$$

$$\text{Age Factor} = \left(\frac{\text{Actual Age in Months}}{\text{Expected Life in Months}}\right) - 1$$

Example: $\left(\frac{102}{84}\right) - 1 = .21$

$$\text{Usage Factor} = \left(\frac{\text{Estimated Mileage}}{\text{Expected Life Mileage}}\right) - 1$$

Example: $\left(\frac{223{,}180}{150{,}000}\right) - 1 = .488$

Blended Factor Example: $\left(\frac{[.21 + .488]}{2}\right) = .349$

Equipment and engine operation hour calculation: 1 hour = 25 miles

The pool of vehicles identified by the Blended Factor analysis is narrowed by reviewing cost data to determine if it is more economical to continue maintaining a vehicle or to replace it.

- Crewing data helps determine how many vehicles the Company has relative to its workforce and that workforce's needs, ensuring that a replacement strategy continues to deliver the right number and types of vehicles.
- Fleet utilization data helps identify if any vehicles are not being fully used.

In addition to the Fleet Vehicle Capital Replacement Plan, the Company also expands its fleet as necessary to specifically support workforce expansion. As detailed in the prior Workforce section of this report, the Company's increased distribution investments require expansion of key parts of the workforce, which will in turn require an expanded fleet.

To support fleet expansion, the Company compares current fleet resources with projected crewing levels before expansion takes place, identifying any gaps indicated by the crewing model, and then develops a plan to procure vehicles needed to close those gaps, informed by qualitative inputs from the affected workforce areas with relevant knowledge about the work to be done.

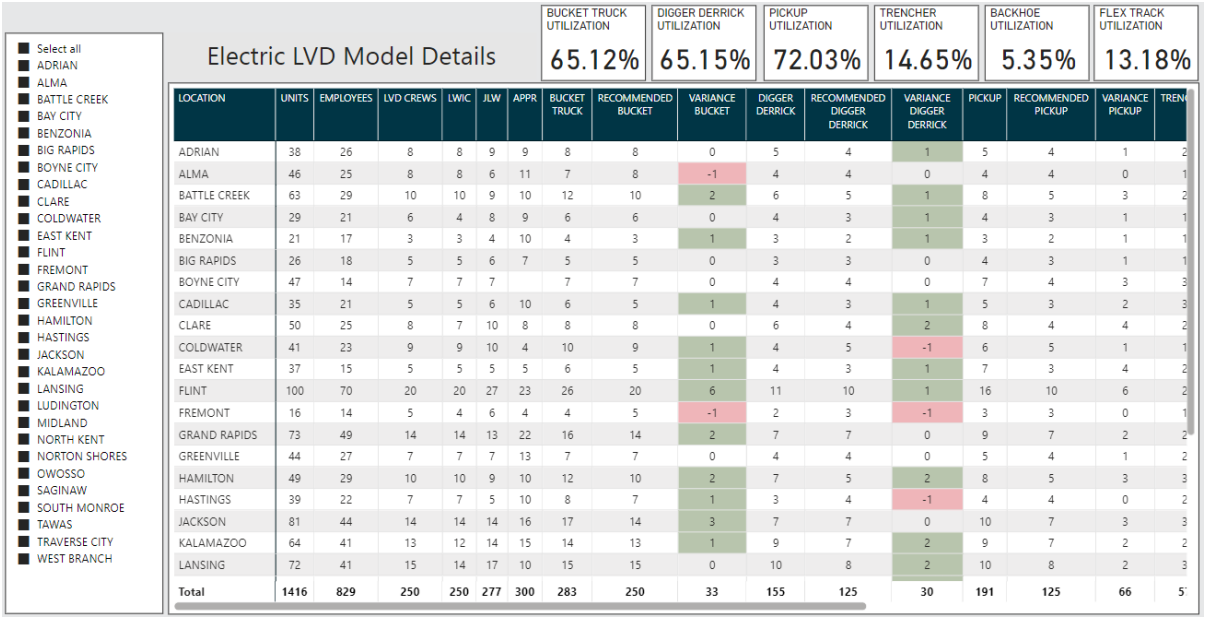
To address immediate needs, the Company has established contracts with multiple fleet unit vendors. These vendors can supply trucks and equipment as necessary to bridge potential gaps with relatively short notice.

As the Company develops the scope of various projects, a clearer understanding of the specific equipment and resources required are determined based on the workforce needed. This process helps in identifying gaps where additional or different equipment might be needed.

The Company has developed a Crewing Model that helps forecast where potential gaps exist to aid in determining proper equipment levels throughout the business. An illustrative example of the Crewing Model is shown below.

Figure 137

Electric Crewing Model



- Select all
- ADRIAN
- ALMA
- BATTLE CREEK
- BAY CITY
- BENZONIA
- BIG RAPIDS
- BOYNE CITY
- CADILLAC
- CLARE
- COLDWATER
- EAST KENT
- FLINT
- FREMONT
- GRAND RAPIDS
- GREENVILLE
- HAMILTON
- HASTINGS
- JACKSON
- KALAMAZOO
- LANSING
- LUDINGTON
- MIDLAND
- NORTH KENT
- NORTON SHORES
- OWOSSO
- SAGINAW
- SOUTH MONROE
- TAWAS
- TRAVERSE CITY
- WEST BRANCH

Electric LVD Model Details

BUCKET TRUCK UTILIZATION	DIGGER DERRICK UTILIZATION	PICKUP UTILIZATION	TRENCHER UTILIZATION	BACKHOE UTILIZATION	FLEX TRACK UTILIZATION
65.12%	65.15%	72.03%	14.65%	5.35%	13.18%

LOCATION	UNITS	EMPLOYEES	LVD CREWS	LWIC	JLW	APPR	BUCKET TRUCK	RECOMMENDED BUCKET	VARIANCE BUCKET	DIGGER DERRICK	RECOMMENDED DIGGER DERRICK	VARIANCE DIGGER DERRICK	PICKUP	RECOMMENDED PICKUP	VARIANCE PICKUP	TREN
ADRIAN	38	26	8	8	9	9	8	8	0	5	4	1	5	4	1	2
ALMA	46	25	8	8	6	11	7	8	-1	4	4	0	4	4	0	1
BATTLE CREEK	63	29	10	10	9	10	12	10	2	6	5	1	8	5	3	2
BAY CITY	29	21	6	4	8	9	6	6	0	4	3	1	4	3	1	1
BENZONIA	21	17	3	3	4	10	4	3	1	3	2	1	3	2	1	1
BIG RAPIDS	26	18	5	5	6	7	5	5	0	3	3	0	4	3	1	1
BOYNE CITY	47	14	7	7	7		7	7	0	4	4	0	7	4	3	3
CADILLAC	35	21	5	5	6	10	6	5	1	4	3	1	5	3	2	3
CLARE	50	25	8	7	10	8	8	8	0	6	4	2	8	4	4	2
COLDWATER	41	23	9	9	10	4	10	9	1	4	5	-1	6	5	1	1
EAST KENT	37	15	5	5	5	5	6	5	1	4	3	1	7	3	4	2
FLINT	100	70	20	20	27	23	26	20	6	11	10	1	16	10	6	2
FREMONT	16	14	5	4	6	4	4	5	-1	2	3	-1	3	3	0	1
GRAND RAPIDS	73	49	14	14	13	22	16	14	2	7	7	0	9	7	2	2
GREENVILLE	44	27	7	7	7	13	7	7	0	4	4	0	5	4	1	2
HAMILTON	49	29	10	10	9	10	12	10	2	7	5	2	8	5	3	3
HASTINGS	39	22	7	7	5	10	8	7	1	3	4	-1	4	4	0	2
JACKSON	81	44	14	14	14	16	17	14	3	7	7	0	10	7	3	3
KALAMAZOO	64	41	13	12	14	15	14	13	1	9	7	2	9	7	2	2
LANSING	72	41	15	14	17	10	15	15	0	10	8	2	10	8	2	3
Total	**1416**	**829**	**250**	**250**	**277**	**300**	**283**	**250**	**33**	**155**	**125**	**30**	**191**	**125**	**66**	**5**

Conclusion and Financial Summary

The Company is modernizing its electric distribution system to safely deliver clean, affordable, reliable power to customers throughout Michigan. **The goal is simple: fewer and shorter power outages for customers.** The vision for the grid is a blueprint for serving Michigan today and innovating to meet the challenges of the coming decades.

The *Reliability Roadmap*, laying out the investment levels summarized in the chart below, charts a new course for the Company in terms of reliability, resiliency, and investment.

The Company has identified **severe weather and technological adoption as the most pressing challenges** to the future grid and modeled the circuit level impacts from these risks through 2050.

This plan will underpin the Company's strategy for distribution investment planning to mitigate the current risk of severe weather and storms, and will serve as a bridge from our current grid to a grid capable of achieving the following reliability objectives:

1. **Delivering reliability performance into the 2nd quartile of nationwide utilities.**
2. **Delivering a grid where no single outage event will affect more than 100,000 customers.**
3. **Delivering a grid where no customer will be without power for more than 24 hours following an outage event.**

The *Reliability Roadmap* will also **significantly improve the Company's SAIFI performance** over the next decade when compared to what would be provided by recent electric rate case-approved levels of investment.

Increased risks from weather and technological adoption will require a significant shift in investment levels and strategy to mitigate the risks from extreme weather and improve the reliability of electric power.

The *Reliability Roadmap* features a unique approach for each voltage system, and a detailed work plan for each asset type.

- The plan for the LVD system will mitigate the worst effects of extreme weather and begin proactive planning for an increasingly electrified future, while the plan for the HVD system will focus on maintaining recent progress through proactively inspecting all assets repairing components on the HVD system to keep them within their useful lifecycle.
- This plan will focus on assets to modernize and harden the Company's electric distribution system to safely provide power with fewer, shorter, and less frequent power outages for customers through the Five Fundamentals Framework: **Fix, Fuse, Fractionalize, Fortify** and **Forestry**.

To execute on this vision, the plan proposes to invest over the next 5 years in the following areas:

FIGURE 138
INVESTMENT PLAN (2025-2029)

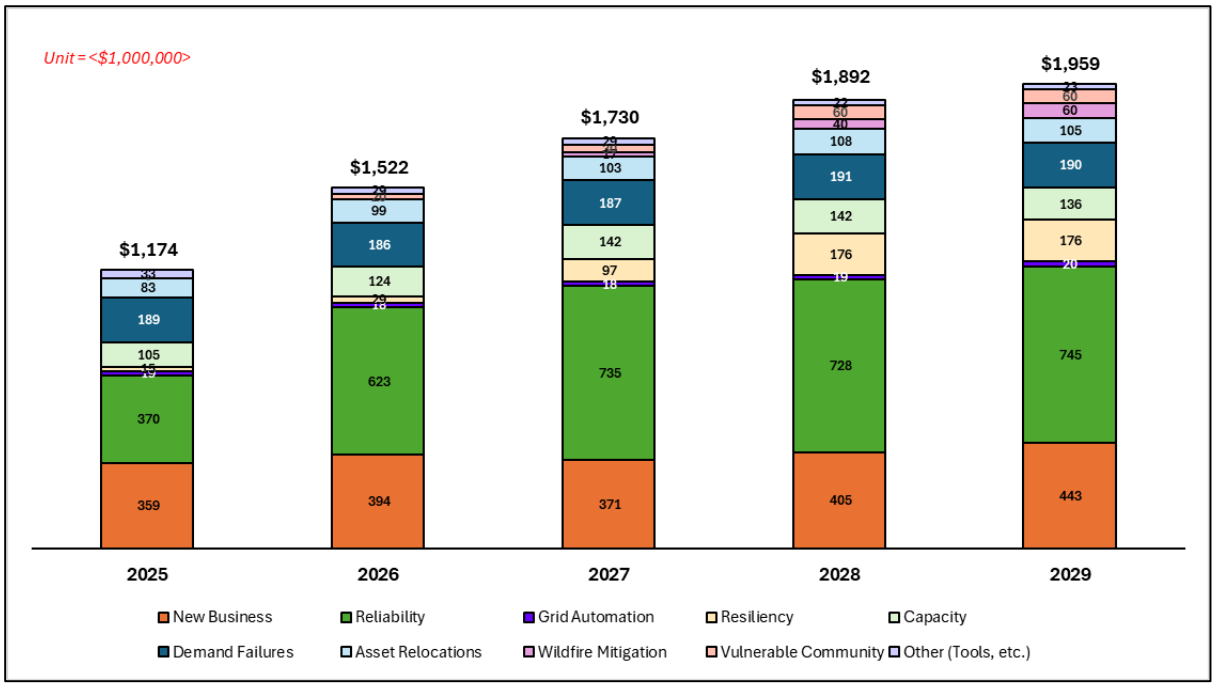
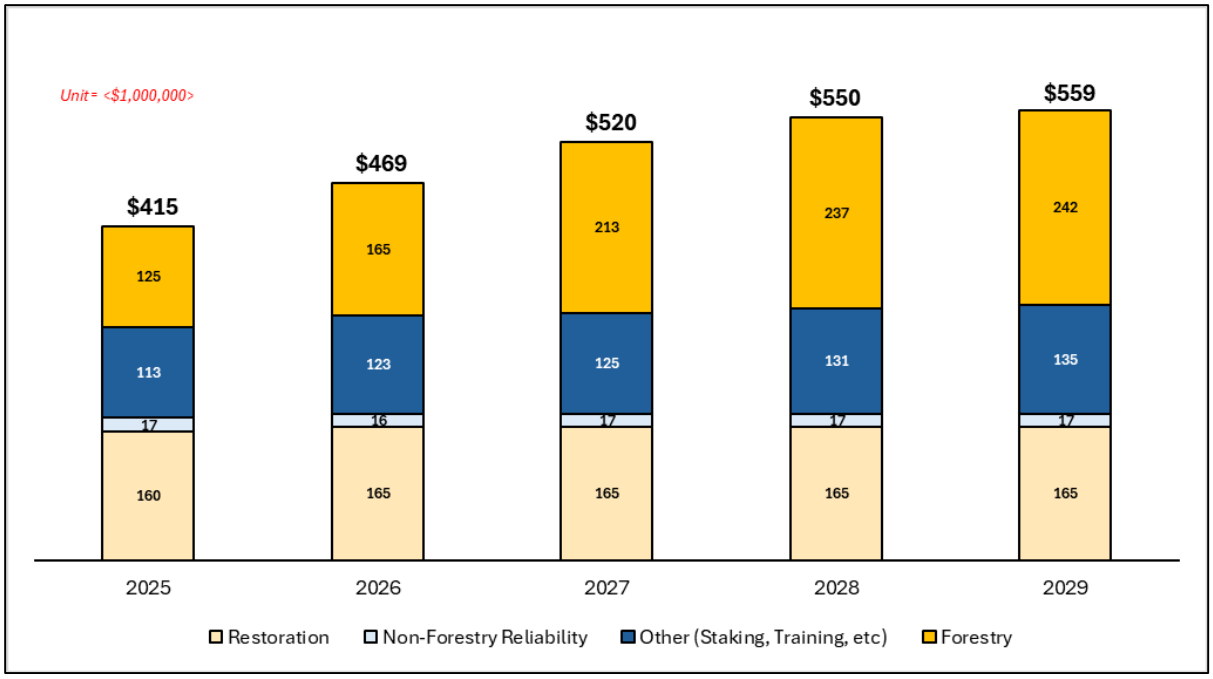


FIGURE 139
O&M PLAN (2025-2029)



This plan also incorporates Environmental Justice into its planning for capital projects and maintenance to ensure disadvantaged communities receive reliable power.

- The Forestry Line Clearing work included in this plan is essential to **addressing the largest single risk to reliability on LVD system** and the Company has developed a prescriptive line clearing impact analysis, with a focus on reliability metrics and tree-caused incidents to inform this work.
- The Company is **expanding its use of data-driven strategies** to guide its LVD full circuit clearing and ramp up to a 5-year clearing cycle for all distribution lines.
- Technology, Analytics, and Grid Modernization will complement the asset investments through developing **new tools and systems to improve the way the Company monitors, controls, and optimizes assets.** Digital will serve as the accelerant to achieve our reliability aspirations by leveraging artificial intelligence, machine learning, and automation to optimize processes, identify trends, and improve customer experiences.

The work described in this Plan relies on adequate field resources, both internal to the Company and externally contracted, to match the work demand.

Our unionized workforce is an essential component for the successful continued investment into the electric distribution system. The Company has seen continued field resource growth over the last 5 years, and has been deliberate in matching the forecasted work demand.

This plan will accelerate this growth into the future with a combination of new resiliency investment and increased maintenance of our system.

As described earlier in the Highlights of the Reliability Roadmap section, the Company fundamentally believes that the **investments outlined in this plan will deliver the safety, reliability, and resiliency benefits** that customers expect. The Company plans to seek recovery for these investments. Timely recovery of the costs of the investments described in this plan is essential to delivering the desired improvements in performance.

The Company looks forward to working with the MPSC, Staff, and the broader set of stakeholders as this plan is executed and further improved over time.

The Company plans to file updates to this plan, adding future years of investment and accounting for additional years of actual spending, with each subsequent rate case filing as an exhibit supporting test year investments.

Appendix A – Grid Archetype Details and Supporting Figures

Figure 140

CIRCUIT CHARACTERISTICS FOR ARCHETYPE CLASSIFICATION - EXAMPLE

	LVD Archetypes							
	#1	#2	#3	#4	#5	#6	#7	TOTAL
LVD Focused Statistics								
SUMMARY STATISTICS								
# of Circuits	248	233	257	492	341	213	259	**2,043**
% of Total	*12%*	*11%*	*13%*	*24%*	*17%*	*10%*	*13%*	***100%***
CUSTOMER								
# of Customers	11,844	152,356	161,670	763,240	257,832	165,754	327,777	**1,840,473**
% of Total Customers	*1%*	*8%*	*9%*	*41%*	*14%*	*9%*	*18%*	***100%***
Average # of Customers/ Circuit	48	654	629	1551	756	778	1266	**901**
Residential Net Promoter Score (CMS Nov. Survey; Sum of respondents)	-	15%	21%	20%	12%	10%	10%	**15%**
Promoters	-	26	53	221	70	71	111	**552**
Neutrals	-	18	31	123	47	30	66	**315**
Detractors	-	17	29	127	50	56	85	**364**
# of Critical Customers (e.g., Hospital, Police, Telephone etc.)	69	188	120	276	125	40	103	**921**
% of Total Critical Customers	*7%*	*20%*	*13%*	*30%*	*14%*	*4%*	*11%*	***100%***
% of Circuits serving one or more Critical Customer	*23%*	*42%*	*25%*	*31%*	*25%*	*12%*	*27%*	***0***
# of Priority Customers (e.g., Major customers, Business centers)	446	1,053	806	1,848	919	445	725	**6,242**
% of Total Priority Customers	*7%*	*17%*	*13%*	*30%*	*15%*	*7%*	*12%*	***100%***
% of Circuits serving one or more Priority Customer	*65%*	*90%*	*83%*	*91%*	*71%*	*65%*	*75%*	***79%***
OPERATIONS								
Total Line Miles	577	3,348	2,390	11,134	15,281	10,149	17,467	**60,348**
Median Line Miles/ Circuit	1	12	9	20	42	48	60	**18**
Average Line Miles/ Circuit	2	14	9	23	45	48	67	**29**
Standard Deviation of Line Miles/ Circuit	4	10	5	13	22	20	35	**28**
Overhead Miles	289	2,387	1,556	7,622	14,138	9,249	15,693	**50,934**
Overhead Miles % of Total	*50%*	*71%*	*65%*	*68%*	*93%*	*91%*	*90%*	***84%***
Underground Miles	289	961	835	3,513	1,142	900	1,775	**9,414**
Underground Miles % of Total	*50%*	*29%*	*35%*	*32%*	*7%*	*9%*	*10%*	***16%***
Median Customers/ Line Mile	15	47	69	71	19	16	19	**31**

Figure 141

CALCULATIONS OF LVD ARCHETYPE ENVELOPE GUARDRAILS – ILLUSTRATIVE EXAMPLE

LVD Planned Capital Projects (Excludes forestry)
All spend values are loaded

Year	Illustrative
Total LVD Budget Allocation	$225M
Envelope Percent Change	20%

		LVD						
Archetype Metrics	**TOTAL**	**#1**	**#2**	**#3**	**#4**	**#5**	**#6**	**#7**
# of Circuits (LVD)	***2,163***	*422*	*224*	*260*	*476*	*337*	*258*	*186*
Spend/ Circuit (LVD)	**$104,022**	$43.9M	$23.3M	$27.0M	$49.5M	$35.1M	$26.8M	$19.3M
# of Customers (LVD Circuits)	**1,782,404**	*15,334*	*157,564*	*178,952*	*712,991*	*274,157*	*201,343*	*242,063*
Spend/ Customer (LVD)	**$126**	$1.9M	$19.9M	$22.6M	$90.0M	$34.6M	$25.4M	$30.6M
Total Line Miles (LVD)	**58,190**	*528*	*3,245*	*2,666*	*11,221*	*14,775*	*12,749*	*13,006*
Spend/ Line Mile (LVD)	**$3,867**	$2.0M	$12.5M	$10.3M	$43.4M	$57.1M	$49.3M	$50.3M
Yearly SAIDI Contribution (Excl. MED; Excluding HVD, '15-19)	***153***	*0.72*	*12.29*	*6.79*	*38.23*	*23.65*	*27.00*	*44.67*
Spend/ Minute of SAIDI Contribution	**$1,467,333**	$1.1M	$18.0M	$10.0M	$56.1M	$34.7M	$39.6M	$65.5M
Yearly SAIFI Contribution (Excl. MED; Excluding HVD, '15-19)	**0.76**	*0.00*	*0.07*	*0.04*	*0.22*	*0.12*	*0.13*	*0.19*
Spend/ Frequency Contribution	**$294M**	$1.1M	$19.5M	$11.1M	$63.7M	$34.4M	$38.6M	$56.6M
Guardrail Analysis								
Median Allocated Spend per Archetype	**$225M**	$2.1M	$20.7M	$11.8M	$59.5M	$36.8M	$40.9M	$53.3M
Median spend as a % of Total	***100%***	*0.9%*	*9.2%*	*5.3%*	*26.4%*	*16.3%*	*18.2%*	*23.7%*
Low Budget Spend Envelope (-20%)	**$180M**	$1.6M	$16.6M	$9.5M	$47.6M	$29.4M	$32.7M	$42.6M
Medium Budget Spend Envelope (Base)	**$225M**	$2.1M	$20.7M	$11.8M	$59.5M	$36.8M	$40.9M	$53.3M
High Budget Spend Envelope (+20%)	**$270M**	$2.5M	$24.8M	$14.2M	$71.3M	$44.1M	$49.1M	$64.0M

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

2021-2025 Distribution Unit Costs

Case No.: U-22070
Exhibit No.: A-96 (EMD-12)
Page: 1 of 2
Witness: EMDuke
Date: June 2026

Line No.	Program / Investment Category	2021 (a) Capital	2021 (b) Projects	2021 (c) Unit Cost	2022 (d) Capital	2022 (e) Projects	2022 (f) Unit Cost	2023 (g) Capital	2023 (h) Projects	2023 (i) Unit Cost	2024 (j) Capital	2024 (k) Projects	2024 (l) Unit Cost	2025 (m) Capital	2025 (n) Projects	2025 (o) Unit Cost
1	**Lines New Business - LVD**	**$ 111,920,506**	**10,652**		**$ 128,886,338**	**9,662**		**$ 136,184,733**	**9,980**		**$ 116,118,244**	**9,040**		**$ 114,567,658**	**9,134**	
2	New Services	$ 111,920,506	10,652	$ 10,507	$ 128,886,338	9,662	$ 13,340	$ 136,184,733	9,980	$ 13,646	$ 116,118,244	9,040	$ 12,971	$ 114,567,658	9,134	$ 12,542
3	**Lines Strategic Customers - HVD**	**$ 20,268,195**	**7**		**$ 4,279,998**	**2**		**$ 11,070,690**	**6**		**$ 57,836,000**	**7**		**$ 40,821,378**	**2**	
4	Investment Category	$ 20,268,195	7	$ 2,895,456	$ 4,279,998	2	$ 2,139,999	$ 11,070,690	6	$ 1,845,115	$ 57,836,000	7	$ 8,262,286	$ 40,821,378	2	**$ 20,410,689**
5	**Metro New Business**	**$ 2,430,593**	**23**		**$ 1,856,029**	**43**		**$ 1,588,725**	**41**		**$ 11,187,596**	**34**		**$ 6,209,984**	**42**	
6	Projects	$ 2,430,593	23	$ 105,678	$ 1,856,029	43	$ 43,163	$ 1,588,725	41	$ 38,749	$ 11,187,596	34	$ 329,047	$ 6,209,984	42	$ 147,857
7	**Transformers - LVD**	**$ 37,927,064**	**10,433**		**$ 49,208,671**	**12,496**		**$ 64,137,462**	**15,047**		**$ 122,886,409**	**18,954**		**$ 152,452,000**	**17,414**	
8	Transformers	$ 37,927,064	10,433	$ 3,635	$ 49,208,671	12,496	$ 3,938	$ 64,137,462	15,047	$ 4,262	$ 122,886,409	18,954	$ 6,483	$ 152,452,000	17,414	$ 8,755
	New Business															
9	**Lines Reliability - LVD**	**$ 39,451,348**	**1,293**		**$ 50,631,252**	**10,745**		**$ 34,935,151**	**7,949**		**$ 25,824,724**	**751**		**$ 85,434,295**	**1,531**	
10	Targeted Circuit Improvements (projects)	$ 23,427,418	209	$ 112,093	$ 42,034,097	10,546	$ 3,986	$ 27,278,225	7,798	$ 3,498	$ 17,763,268.00	503	$ 35,315	$ 66,659,512	826	$ 80,702
11	Pole Replacements (poles)	$ 10,599,623	1,055	$ 10,047	$ 2,534,948	172	$ 14,738	$ 1,894,863	137	$ 13,831	$ 1,330,180.00	231	$ 5,758	$ 7,613,230	640	$ 11,896
12	Circuit Exit Enhancements (projects)	$ 1,266,069	29	$ 43,658	$ 1,403,810	27	$ 51,993	$ 655,794	14	$ 46,842	$ 529,504.00	17	$ 31,147	$ 3,574,045	65	$ 54,985
13	ROW Easements	$ 4,158,238	N/A		$ 4,658,397	N/A		$ 5,106,269	N/A		$ 6,201,772.00	N/A		$ 7,587,498	n/a	
14	**Lines Reliability - HVD**	**$ 58,092,338**	**570**		**$ 42,565,119**	**715**		**$ 21,703,195**	**254**		**$ 32,263,573**	**552**		**$ 99,313,770**	**1,841**	
15	Line rebuilds (miles)	$ 32,946,529	32	$ 1,029,579	$ 18,219,292	40	$ 455,482	$ 15,077,709	9	$ 1,675,301	$ 8,976,122	12	$ 748,010	$ 18,257,970	11	$ 1,659,815
16	Pole top rehabilitations (miles)	$ 13,583,527	110	$ 123,487	$ 7,195,963	95	$ 75,747	$ 504,706	7	$ 72,101	$ 5,583,078	49	$ 113,940	$ 15,124,928	90	$ 168,055
17	Pole replacements (poles)	$ 9,739,363	402	$ 24,227	$ 15,152,831	545	$ 27,803	$ 6,011,798	234	$ 25,691	$ 16,201,485	488	$ 33,200	$ 53,015,880	1,327	$ 39,952
18	Switches (incl. SCADA additions) (locations)	$ 1,822,919	26	$ 70,112	$ 1,997,034	35	$ 57,058	$ 108,982	4	$ 27,245	$ 607,027	3	$ 202,342	$ 3,649,543	13	$ 280,734
	Pole top assembly replacements													$ 5,315,072	344	$ 15,451
	HVD line sensors													$ 838,268	56	$ 14,969
19	ROW Easements										$ 895,861			$ 3,112,109		
20	**Substations Reliability - LVD**	**$ 19,017,331**	**85**		**$ 16,884,427**	**72**		**$ 14,708,696**	**16**		**$ 17,573,928**	**48**		**$ 43,277,673**	**32**	
21	New or rebuilt substations	$ 1,124,659	2	$ 562,330	$ 4,628,403	4	$ 1,157,101	$ 6,067,843	3	$ 2,022,614	$ 9,317,237	7	$ 1,331,034	$ 14,455,558	1	$ 14,455,558
22	Mobile substations	$ 4,745,155	1	$ 4,745,155	$ 3,333,542	1	$ 3,333,542	$ 2,250,653	2	$ 1,125,327	$ 25,620	-	$ -	$ 6,387,921	0	$ -
23	Animal mitigation	$ 4,655,023	50	$ 93,100	$ 4,701,094	31	$ 151,648	$ 1,026,099	6	$ 171,017	$ 2,219,122	18	$ 123,285	$ 816,547	5	$ 163,309
24	Regulator replacements	$ 879,762	15	$ 58,651	$ 728,105	31	$ 23,487	$ 5,481	-	$ -	$ 715,226	14	$ 51,088	$ 4,283	0	$ -
25	Transformer replacements	$ 5,115,612	7	$ 730,802	$ 3,287,007	3	$ 1,095,669	$ 5,245,914	3	$ 1,748,638	$ 3,894,229	3	$ 1,298,076	$ 15,143,088	4	$ 3,785,772
26	Other Projects and Charges	$ 2,497,118	10	$ 249,712	$ 206,276	2	$ 103,138	$ 112,705	2	$ 56,353	$ 1,402,494	6	$ 233,749	$ 6,470,276	22	$ 294,103
27	**Substations Reliability - HVD**	**$ 3,455,799**	**59**		**$ 3,992,844**	**62**		**$ 3,261,649**	**42**		**$ 5,715,476**	**55**		**$ 22,824,868**	**126**	
28	Circuit breaker/switcher replacements	$ 2,216,790	19	$ 116,673	$ 1,470,249	14	$ 105,018	$ 2,678,521	17	$ 157,560	$ 2,659,728	20	$ 132,986	$ 9,687,026	29	$ 334,035
29	Transformer bushing replacements	$ 539,983	5	$ 107,997	$ 472,881	4	$ 118,220	$ 38,952	N/A	N/A	$ 1,367,384	10	$ 136,738	$ 1,203,502	12	$ 100,292
30	Switch replacements	$ 567,972	12	$ 47,331	$ 909,232	22	$ 41,329	$ 211,344	5	$ 42,269	$ 1,083,967	10	$ 108,397	$ 3,283,855	28	$ 117,281
31	Other	$ 131,054	23	$ 5,698	$ 1,140,482	22	$ 51,840	$ 332,832	20	$ 16,642	$ 604,397	15	$ 40,293	$ 8,650,485	57	$ 151,763
32	**System Protection**	**$ 2,620,098**	**13**		**$ 4,503,577**	**41**		**$ 4,386,998**	**36**		**$ 4,848,000**	**17**		**$ 5,244,000**	**17**	
33	Total Relay Replacements	$ 2,620,098	13	$ 201,546	$ 4,503,577	41	$ 109,843	$ 4,386,998	36	$ 121,861	$ 4,848,000	17	$ 285,176	$ 5,244,000	17	**$ 308,471**
34	**Repetitive Outages - LVD**	**$ 10,713,652**	**350**		**$ 9,253,597**	**346**		**$ 4,082,239**	**122**		**$ 4,491,324**	**215**		**$ 12,902,618**	**301**	
35	Total Repetitive Outage Projects	$ 10,713,652	350	$ 30,610	$ 9,253,597	346	$ 26,744	$ 4,082,239	122	$ 33,461	$ 4,491,324	215	$ 20,890	$ 12,902,618	301	$ 42,866
36	**Metro Reliability**	**$ 5,737,248**	**20**		**$ 4,124,833**	**37**		**$ 3,985,200**	**35**		**$ 6,689,896**	**22**		**$ 4,628,866**	**18**	
37	Obsolete or Needed Civil Assets	$ 1,769,322	1	$ 1,769,322	$ 712,306	9	$ 79,145	$ 1,554,333	5	$ 310,867	$ 3,228,969	6	$ 538,161	$ 2,048,884	7	$ 292,698
38	Obsolete or Needed Electrical Assets	$ 2,085,336	14	$ 148,953	$ 1,559,203	16	$ 97,450	$ 624,775	15	$ 41,652	$ 684,703	8	$ 85,588	1,825,039	5	$ 365,008
39	Dead Fronting Equipment	$ 1,827,937	4	$ 456,984	$ 1,832,347	10	$ 183,235	$ 873,040	13	$ 67,157	$ 1,634,741	5	$ 326,948	$ (20,183)	4	$ (5,046)
40	New Technologies	$ 54,653	1		$ 20,978	2	$ 10,489	$ 933,052	2	$ 466,526	$ 1,141,484	3	$ 380,495	$ 775,127	2	$ 387,563
41	**Grid Automation**	**$ 74,153,885**	**2,343**		**$ 52,816,893**	**3,167**		**$ 29,037,543**	**2,575**		**$ 20,195,352**	**3,206**		**$ 20,179,288**	**1,210**	
42	DSCADA & SCADA	$ 19,213,429	84	$ 228,731	$ 13,954,409	64	$ 218,038	$ 5,446,740	11	$ 495,158	$ 1,341	0		***shifted to LVD Substations Reliability - see witness LaFrance's testimony**		
43	ATR Loops	$ 16,707,963	25	$ 668,319	$ 15,868,980	36	$ 440,805	$ 11,110,673	24	$ 462,945	*shifted to LVD Lines Reliability - see Fig. 37 of witness Partlan's testimony					
44	Line Sensors	$ 8,085,793	1,719	$ 4,704	$ 3,518,698	2,342	$ 1,502	$ 5,969,833	2,379	$ 2,509	$ 10,831,582	2979	$ 3,636	$ 6,397,990	1005	$ 6,366
45	Voltage Regulator Controllers	$ 6,358,823	162	$ 39,252	$ 5,654,047	367	$ 15,406	$ 3,143,732	160	$ 19,648	$ 3,501,251	156	$ 22,444	$ 9,369,559	205	$ 45,705
46	LVD Capacitor Upgrades & Replacements	$ 787,394	353	$ 2,231	$ 415,640	358	$ 1,161	$ 109,507	-		$ 291,425	71	4104.577465			
47	Misc Sub & HVD Work	$ -			$ -											
48	Circuit West	$ 32														
49	Cellular Communications Upgrades															
50	Substation Modernization										$ 3,481	N/A		$ 263	N/A	
51	Advanced Technology Projects	$ 23,696,696	-		$ 13,934,001	-		$ 3,252,695	-		$ 5,524,312			$ 4,411,476	N/A	
52	Substations Comm Upgrades	$ (696,245)	-		$ (528,883)	-		$ 4,364			$ 41,960	N/A				
53	**Lines and Subs Rehabilitation HVD (now Transformer Replacements & Sub Rebuilds)**	**$ 29,896,106**	**779**		**$ 39,183,968**	**867**		**$ 28,395,172**	**634**		**$ 26,676,254**	**603**				
54	Pole replacements	$ 4,007,742	227	$ 17,655	$ 7,098,950	291	$ 24,395	$ 4,277,002	146	$ 29,295	$ 6,981,392	284	$ 24,582			
55	Pole top assembly replacements	$ 5,597,280	541	$ 10,346	$ 5,579,111	563	$ 9,910	$ 4,061,358	482	$ 8,426	$ 3,056,556	301	$ 10,155	**Moved to HVD Lines Reliability and HVD Substations Reliabiltiy - see testimony of Company witness LaFrance**		
56	Switch (incl. MOAB) replacements	$ 552,306	4	$ 138,077	$ 958,270	10	$ 95,827	$ 273,642	5	$ 54,728	$ 1,422,525	17	$ 83,678			
57	Miscellaneous other replacements	$ 46,576	7	$ 6,654	$ 186,377	3	$ 62,126	$ 181,203	1	$ 181,203	$ 24,695	1	$ 24,695			
58	HVD substation replacement projects	$ 19,692,203			$ 25,361,260			$ 19,601,967			$ 15,191,086					
59	**Substations Rehabilitation LVD**	**$ 18,379,139**	**32**		**$ 10,941,033**	**20**		**$ 8,481,963**	**12**		**$ 13,860,340**	**11**		**$ 22,881,389**	**13**	
60	Allis Chalmers transformer replacements	$ 12,464,595	15	$ 830,973	$ 6,408,239	5	$ 1,281,648	$ 4,499,628	4	$ 1,124,907	$ 6,018,840	3	$ 2,006,280	$ 10,248,206	4	$ 2,562,052
61	Equipment replacement and regulatory	$ 3,908,037	14	$ 279,146	$ 3,077,226	13	$ 236,710	$ 3,982,335	8	$ 497,792	$ 7,841,500	8	$ 980,187	$ 12,633,183	9	$ 1,403,687
62	Transformer at imminent risk of failure	$ 2,006,506	3	$ 668,835	$ 1,455,568	2	$ 727,784	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -
63	**Lines Rehabilitation - LVD**	**$ 33,547,774**	**809**		**$ 29,068,083**	**804**		**$ 12,529,815**	**584**		**$ 44,434,897**	**9,959**		**$ 16,973,687**	**1,501**	
64	Security assessment repairs projects*	$ 23,684,410	267	$ 88,706	$ 19,095,171	188	$ 101,570	$ 7,641,659	180	$ 42,454	31,650,187	8,893	$ 3,559	-	-	$ -
65	Imminent rehabilitation	$ 9,863,364	542	$ 18,198	$ 9,972,912	616	$ 16,190	4,888,156	404	$ 12,099	$ 11,592,837.00	577	$ 20,092	$ 13,068,529.09	530	$ 24,658
66	Modern Replacement Program	$ -	-		$ -	-		$ -	-		$ 1,191,873.00	489	$ 2,437	$ 3,905,157.49	971	$ 4,022
67	**Metro Rehabilitation**	**$ 3,163,241**	**7**		**$ 4,678,237**	**25**		**$ 7,033,641**	**25**		**$ 2,687,522**	**22**		**$ 4,511,531**	**22**	
68	Crushed duct replacements	$ 2,545,721	5	$ 509,144	$ 1,562,800	5	$ 312,560	$ 2,704,924	7	$ 386,418	$ 513,480	6	$ 85,580	$ (51,209)	3	$ (17,070)
69	Vault or manhole rehabilitation	$ 617,520	2	$ 308,760	$ 3,115,436	20	$ 155,772	$ 4,328,718	18	$ 240,484	$ 2,070,385	11	$ 188,217	$ 4,509,412	17	$ 265,260
70	Imminent failure										$ 103,657	5	$ 20,731	$ 53,328	2	$ 26,664
	Grid Storage	**$ 4,605,834**	**5**		**$ 646,667**	**4**										
71	Capacity Upgrade Deferral	$ 4,293,304	1	$ 4,293,304	$ 219,727	1	$ 219,727									
72	Islanded Battery	$ 161,717	1	$ 161,717	$ 357,301	1	$ 357,301									
73	Distribution Automation Battery	$ 1,389	1	$ 1,389	$ -	-										
74	DC-coupled Solar + Storage	$ 9,825	1	$ 9,825	$ -	-										
75	Fast Frequency Regulation Market participation	$ 139,988	1	$ 139,988	$ 6,110	1	$ 6,110									
76	Parkview Battery Main Controller Replacement				$ 63,529	1	$ 63,529									
77	**Reliability**															

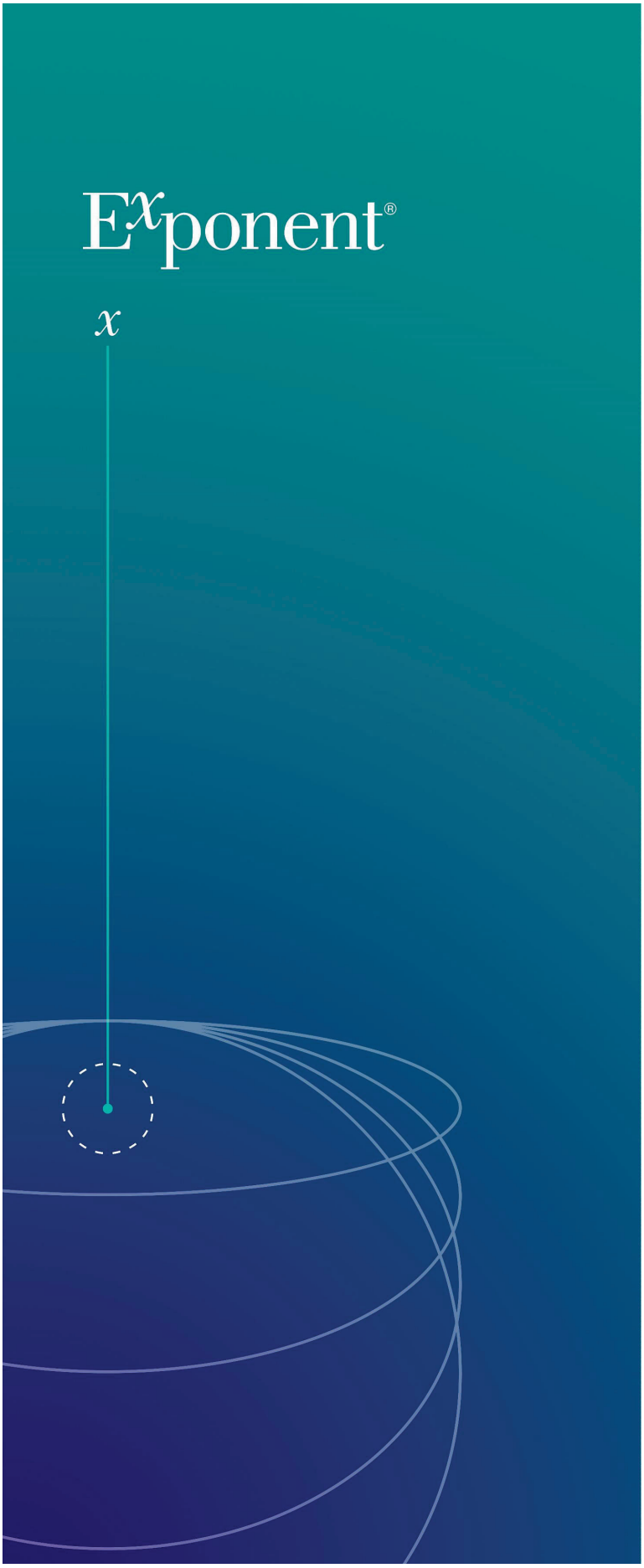
***Security assessment repair now in LVD Lines Demand Failures - see testimony of witness Partlan**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

2021-2025 Distribution Unit Costs

Case No.: U-22070
Exhibit No.: A-96 (EMD-12)
Page: 2 of 2
Witness: EMDuke
Date: June 2026

Line No.	Program / Investment Category	2021 (d) Capital	2021 (e) Projects	2021 (f) Unit Cost	2022 (g) Capital	2022 (h) Projects	2022 (i) Unit Cost	2023 (j) Capital	2023 (k) Projects	2023 (l) Unit Cost	2024 (m) Capital	2024 (n) Projects	2024 (o) Unit Cost	2025 (m) Capital	2025 (n) Projects	2025 (o) Unit Cost
1	**Lines Capacity - LVD**	**$ 8,216,776**	**42**		**$ 7,706,145**	**63**		**$ 2,926,592**	**45**		**$ 9,424,100**	**76**		**$ 17,845,695**	**244**	
2	Overloaded equipment upgrades	$ 5,228,367	34	**$ 153,776**	$ 7,434,754	59	$ 126,013	$ 275,156	29	$ 9,488	$ 6,336,921	56	$ 113,159	$ 11,868,665	192	$ 61,816
3	Lines capacity projects assoc. w/ substation work	$ 2,988,409	8	**$ 373,551**	$ 271,391	4	$ 67,848	$ 2,651,436	16	$ 165,715	$ 3,087,179	20	$ 154,359	$ 5,977,030	52	$ 114,943
4	**Lines & Subs Capacity - HVD**	**$ 17,365,080**	**53**		**$ 29,292,429**	**135**		**$ 25,805,134**	**89**		**$ 27,163,000**	**95**		**$ 20,005,504**	**33**	
5	Load carrying capabilities and voltage support	$ 4,162,164	2	$ 2,081,082	$ 9,364,969	3	$ 3,121,656	$ 6,578,947	2	$ 3,289,473	$ 4,974,403	1	$ 4,974,403	$ 8,512,980	5	$ 1,702,596
6	New interconnections	$ 239,077	12	$ 19,923	$ 2,457,816	15	$ 163,854	$ 1,160,532	25	$ 46,421	$ (1,012,641)	11	$ (92,058)	$ (298,308)	3	$ (99,436)
7	Improved functionality	$ 4,230,554	16	$ 264,410	$ 9,761,576	91	$ 107,270	$ 8,899,117	16	$ 556,195	$ 13,775,703	43	$ 320,365	$ 7,099,117	20	$ 354,956
8	Coordination with Transmission	$ 3,983,908	17	$ 234,348	$ 2,733,013	4	$ 683,253	$ 2,016,771	5	$ 403,354	$ 8,786,917	5	$ 1,757,383	$ 2,848,670	4	$ 712,167
9	ROW procurement	$ 4,749,378	6	$ 791,563	$ 4,975,056	22	$ 226,139	$ 7,149,768	41	$ 174,385	$ 638,618	35	$ 18,246	$ 1,843,045	1	$ 1,843,045
10	**Substations Capacity - LVD**	**$ 15,068,327**	**79**		**$ 12,766,649**	**73**		**$ 14,529,968**	**65**		**$ 25,886,601**	**20**		**$ 33,612,167**	**10**	
11	New substations	$ 8,974,225	5	$ 1,794,845	$ 4,186,031	3	$ 1,395,344	$ 7,436,504	-	-	$ 19,741,625	8	$ 2,467,703	$ 8,504,842	1	$ 8,504,842
12	Existing substations capacity increase projects	$ 5,146,266	17	$ 302,722	$ 6,947,750	7	$ 992,536	$ 4,607,030	8	$ 575,879	$ 6,144,976	12	$ 512,081	$ 25,107,326	9	$ 2,789,703
13	Other Projects and Charges	$ 947,835	57	$ 16,629	$ 1,632,869	63		$ 2,486,433	57	$ 43,622	$ -	-	$ -	$ -	-	$ -
14	**New Business Cap - LVD**	**$ 23,672,169**	**1,553**		**$ 27,187,902**	**1,544**		**$ 29,054,330**	**1,438**		**$ 33,429,196**	**1,294**		**$ 32,679,000**	**1,089**	
15	Orders	$ 23,672,169	1,553	$ 15,243	$ 27,187,902	1,544	$ 17,609	$ 29,054,330	1,438	$ 20,205	33,429,196	1,294	$ 25,834	$ 32,679,000	1,089	$ 30,008
16	**Conservative Voltage Reduction CVR**	**$ 7,191,371**	**204**		**$ 3,145,109**	**160**		**$ 1,310,828**	**38**		**$ 2,246,180**	**56**		**$ 4,976,754**	**176**	
17	Construct Project	$ 7,191,371	204	$ 35,252	$ 3,145,109	160	$ 19,657	$ 1,310,828	38	$ 34,495	$ 2,246,180	56	$ 40,110	$ 4,976,754	176	$ 28,277
	Capacity															
18	**Lines Failures - LVD**	**$ 123,508,957**	**29,986**		**$ 142,776,767**	**31,785**		**$ 159,370,587**	**31,508**		**$ 137,322,405**	**25,905**		**237,073,716**	**27,702**	
19	Service Restoration Orders	$ 123,508,957	29,986	$ 4,119	$ 142,776,767	31,785	$ 4,492	$ 159,370,587	31,508	$ 5,058	$ 137,322,405	25,905	$ 5,301	$ 237,073,716	27,702	**$ 8,558**
20	**Lines & Subs Failures - HVD**	**$ 6,051,000**	**206**		**$ 10,015,000**	**256**		**$ 13,523,830**	**433**		**$ 11,705,270**	**299**		**$ 13,379,934**	**417**	
21	Pole replacements	$ 1,618,000	86	$ 18,800	$ 2,515,000	76	$ 33,092	$ 2,955,115	97	$ 30,465	$ 4,434,237	97	$ 45,714	$ 5,304,485	142	$ 37,356
22	Pole top assembly replacements	$ 905,000	109	$ 8,300	$ 886,000	86	$ 10,302	$ 1,568,123	156	$ 10,052	$ 1,514,290	156	$ 9,707	$ 2,878,524	259	$ 11,114
23	Switch (incl. MOAB) replacements	$ 1,193,000	9	$ 132,600	$ 1,716,000	12	$ 143,000	$ 574,376	5	$ 114,875	$ 849,749	5	$ 169,950	$ 640,668	2	$ 320,334
24	Miscellaneous other replacements	$ 75,000	2	$ 37,300	$ 38,000	8	$ 4,750	$ 130,672	41	$ 3,187	$ 489,181	41	$ 11,931	$ 565,679	14	$ 40,406
25	HVD substation failure projects	$ 2,260,000	N/A		$ 4,860,000	74	$ 65,676	$ 8,295,544	134	$ 61,907	$ 4,417,813			$ 3,990,578		
26	**Substations Failures - LVD**	**$ 12,781,598**	**298**		**$ 8,055,636**	**239**		**$ 14,868,807**	**216**		**$ 11,478,428**	**258**		**$ 11,268,483**	**259**	
27	Allis Chalmers Substation Transformer Replacements	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -
28	Regulators	$ 2,793,635	86	$ 32,484	$ 2,294,466	67	$ 34,246	$ 3,043,913	52	$ 58,537	$ 5,289,888	88	$ 60,112	$ 4,985,239	83	$ 60,063
29	Reclosers	$ 867,933	53	$ 16,376	$ 999,513	58	$ 17,233	$ 824,022	34	$ 24,236	$ 1,686,206	50	$ 33,724	$ 1,071,165	61	$ 17,560
30	Transformers	$ 5,957,753	6	$ 992,959	$ 1,429,349	2	$ 714,674	$ 3,296,081	4	$ 824,020	$ 539,677	1	$ 539,677	$ 2,009,779	2	$ 1,004,889
31	End-of-Life Condition – Substation Rebuild	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -
32	Other Equipment and Charges	$ 3,162,277	153	$ 20,668	$ 3,332,308	112	$ 29,753	$ 7,704,792	126	$ 61,149	$ 3,962,656	119	$ 33,300	$ 3,202,300	113	$ 28,339
33	**Meters - LVD**	**$ 22,368,078**	**205,706**		**$ 30,974,526**	**122,436**		**$ 58,653,212**	**148,820**		**$ 35,076,620**	**71,154**		**$ 27,379,900**	**52,144**	
34	Meters, Transformers, & Sockets	$ 22,368,078	205,706	$ 109	$ 30,974,526	122,436	$ 253	$ 58,653,212	148,820	$ 394	$ 35,076,620	71,154	$ 493	$ 27,379,900	52,144	$ 525
35	**Metro Failures**	**$ 50,156**	**11**		**$ 121,581**	**24**		**$ 463,641**	**22**		**$ 17,531**	**10**		**$ (53,307)**	**4**	
36	Projects	$ 50,156	11	$ 4,560	$ 121,581	24	$ 5,066	$ 463,641	22	$ 21,075	$ 17,531	10	$ 1,753	$ (53,307)	4	$ (13,327)
	Demand Failures															
37	**Lines Relocations - LVD**	**$ 38,895,000**	**3,949**		**$ 52,814,000**	**3,727**		**$ 46,849,000**	**3,985**		**$ 51,502,458**	**4,582**		**$ 88,912,518**		
38	Customer requested and other internal relocations	$ 27,202,000	2,856	$ 9,525	$ 27,091,000	2,257	$ 12,003	$ 26,696,000	2,131	$ 12,527	$ 25,443,532	2,718	$ 9,361	$ 30,741,930	2,832	$ 10,855
39	LVD underbuild relocations	$ 5,240,000	264	$ 19,848	$ 11,149,000	234	$ 47,645	$ 7,130,000	199	$ 35,829	$ 5,635,991	224	$ 25,161	$ 5,044,428	157	$ 32,130
40	Make-ready work	$ 6,453,000	829	$ 7,784	$ 14,574,000	1,236	$ 11,791	$ 13,023,000	1,655	$ 7,869	$ 20,422,935	1,640	$ 12,453	$ 53,126,160	1,492	$ 35,607
41	**Lines Relocations - HVD**	**$ 1,709,173**	**17**		**$ 2,564,824**	**18**		**$ 5,319,332**	**36**		**$ 844,774**	**29**		**$ 609,849**	**37**	
42	Projects	$ 1,709,173	17	$ 100,540	$ 2,564,824	18	$ 142,490	$ 5,319,332	36	$ 147,759	$ 844,774	29	$ 29,130	$ 609,849	37	16,482
43	**Metro Relocations**	**$ 6,549,541**	**16**		**$ 6,887,820**	**43**		**$ 5,160,711**	**47**		**$ 11,420,267**	**27**		**$ 14,353,203**	**37**	
44	Projects	$ 6,549,541	16	$ 409,346	$ 6,887,820	43	$ 160,182	$ 5,160,711	47	$ 109,802	$ 11,420,267	27	$ 422,973	$ 14,353,203	37	$ 387,924
	Asset Relocations															
45	**Computer & Equipment**	**$ 378**			**$ 6,272,688**			**$ 412,000**			$ -			**(65,000)**		
46	**Tools**	**$ 11,114,404**	**374**		**$ 3,757,000**	**-**		**$ 5,537,898**			**$ 7,773,000**			**$ 8,461,003**		
47	Truck tool packages	$ 5,885,000	169	$ 34,822	$ -	-		$ 977,898	16	$ 61,119	$ 727,000	24	$ 30,292	$ 2,670,176	67	$ 39,853
48	General capital tools	$ 3,399,728			$ 2,557,000			$ 4,560,000			$ 7,046,000			$ 5,790,827		
49	Reconductoring Equipment	$ 516,068	8		$ 125,000											
50	Employee fall restraint kits	$ 426,424	136		$ 420,000											
51	Substation bird mitigation equipment	$ 48,000	4		$ 70,000											
52	Tool crib/cabinet stock	$ 600,000	30		$ 225,000											
53	Infrared Cameras	$ 54,384	21		$ -											
54	Substation control house battery carts	$ 16,800	3		$ 35,000											
55	Breaker and HVD equipment testers	$ 168,000	3		$ 325,000											
56	**System Control Projects**	**$ 1,193,499**	**107**		**$ 2,520,610**	**11**	$ 229,146	**$ 41,289**	**4**		**$ 896,025**	8		**$ 57,000**		
57	HVD operations projects	$ 180,135	96	$ 1,876	$ 1,836,500	7	$ 262,357		-		$ -					
58	HVD Remote M&C Cap		-	$ -		-			-		$ -					
59	Operating technology enhancements	$ (23,803)	1	$ (23,803)	$ 192,510	2	$ 96,255		-		$ -					
60	Operations center modifications	$ 1,037,167	10	$ 103,717	$ 491,600	2	$ 245,800	$ 41,289	4	$ 10,322	$ 896,025	8	$ 112,003	$ 57,000	1	$ 57,000
61	Emergency Operations Center										$ -	0				
	Electric Other															



Consumers Energy

Reliability and Disconnections Regression Analysis for Environmental Justice Communities

Exponent®

Consumers Energy

Reliability and Disconnections Regression Analysis for Environmental Justice Communities

Exponent Report

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each metric (the Vulnerable group) and all other census tracts within Consumers service territory (the Non-Vulnerable group). Significance is assessed at $\alpha = 0.05$. 66

Limitations

The study presented in this report is intended for use by Consumers Energy Company ("Consumers") to inform their decisions related to distributional equity of electric reliability among the various communities that they serve. While this study is informative, it is understood and agreed that responsibility for these decisions remain fully with Consumers. Proper application of this report requires recognition and understanding of the limitations of both the scope and methodology of the study. The scope of the study was limited to performing regression analysis to assess correlations between electric reliability and: (1) demographic characteristics of communities served by Consumers; and (2) physical characteristics of distribution circuits. The scope of the study also included regression analysis of correlations between residential involuntary disconnections for non-payment and demographic characteristics of communities within Consumers' service territory.

In the analysis, Exponent has relied on data and various other information provided by Consumers. We cannot verify the correctness of this input data and rely on Consumers for their accuracy.

Exponent has exercised professional skill and care ordinarily provided by professionals practicing in the same or similar locality under the same or similar circumstances in the preparation of this report, and the findings presented herein are made based on information available to Exponent as of the date of this report. This report may be supplemented to expand or modify our findings based on additional analysis or review of additional information.

It is noted that the Executive Summary cannot summarize all of Exponent's technical evaluation, analysis, conclusions, and recommendations. Hence, the main part of this report is at all times the controlling document.

Executive Summary

The primary objective of this study was to update the set of analyses previously conducted (i.e., the "2025 Analysis") to quantify differences in the reliability experienced by Environmental Justice ("EJ") and Non-EJ communities within Consumers Energy Company's ("Consumers") service territory from 2020-2024[1] with an additional year's worth of data from 2025. A further objective of this study was to update the regression analysis of rates of residential involuntary disconnection for nonpayment ("disconnection rates") among Consumers' customers that was previously conducted using data from 2020-2023 with data for 2024. We also aimed to refine the disconnection regression analysis by including additional independent variables in the model and providing additional context for the results.

To quantify differences in the reliability experienced by EJ and Non-EJ communities in Consumers' service territory, we used statistical techniques including the binary difference-in-means *t*-test and regression analysis. The results of this analysis suggest that EJ communities tend to experience better average reliability than non-EJ communities, consistent with our findings in the 2025 Analysis. The results of the updated regression analysis also indicate that MiEJScreen Overall Score is statistically significant and correlated with improving reliability as quantified by the following metrics (when all other variables, as well as county and year factors, are held constant): SAIDI including and excluding MEDs; SAIFI including and excluding MEDs; CAIDI including and excluding MEDs; CELID-5 and -24; CEMI-4, -5, and -7; Total Customer Interruptions; and Unique Customers with an Interruption. These findings are consistent with those of the 2025 Analysis.

We also examined differences in the reliability experienced by groups of customers that may be disadvantaged, or reasonably expected to be more vulnerable to disruptions in electric service, and other customers in Consumers' service territory. Consistent with our findings in the 2025 Analysis, we found that Urban census tracts tend to have better average reliability than Rural census tracts; that Low-Income census tracts tend to have better average reliability than High-Income census tracts; and that High-Percent-Minority-Percentile census tracts tend to have better average reliability than Low-Percent-Minority-Percentile census tracts. In 2025, we observed notable exceptions to this general pattern: Non-EJ, Rural, High-Income, and Low-Percent-Minority-Percentile census tracts had better average reliability in terms of the percentage of catastrophic-weather restorations made within 48 hours than EJ, Urban, Low-Income, and High-Percent-Minority-Percentile census tracts. On average, High-Income and Low-Percent-Minority-Percentile census tracts also had better reliability in terms of CAIDI including MEDs and the percentage of all-weather restorations made within 36 hours, than Low-Income and High-Percent-Minority-Percentile census tracts, respectively.

[1] Consumers Energy Company. Rate Case No. U-21870. "Reliability Regression Analysis for Environmental Justice Communities." Exhibit A-135. June 2, 2025.

We also assessed how different physical characteristics of distribution circuits (also called feeders) and the demographic characteristics of the communities they serve relate to their reliability. We found that feeders' physical characteristics, rather than demographic characteristics of the populations they serve, drive differences in reliability across feeders. None of the demographic characteristics – including whether a feeder serves an EJ census tract – had statistically significant correlations with any of the four feeder reliability metrics. Relative to the reference voltage (4.8/8.32 kV Wye Grounded), having an alternative voltage configuration is often statistically significant and has a large effect on reliability. We also found that, consistent with expectations, increasing Primary Miles and Mean Canopy Cover are statistically significant and associated with increases in both SAIDI and SAIFI (both including and excluding MEDs), indicating that increases in these characteristics are associated with worse reliability. Primary Underground Percentage and Customers Per Primary Line Mile had statistically significant negative correlations with all metrics, indicating that increases in these characteristics are associated with improved reliability.

The results of the regression analysis of disconnection rates were enhanced by the addition of electric energy burden (i.e., the percentage of household income that is spent on electric energy costs[2]) to the set of independent variables. As expected, electric energy burden has the greatest correlation with disconnection rate of all the independent variables included in the model. Notably, the statistically significant positive correlation previously observed in the 2025 Analysis between Percentage Minority Population and disconnection rate persists even when electric energy burden (along with the same variables previously included in the model) is controlled for.

[2] United States Department of Energy. Low-Income Energy Affordability Data (LEAD) Tool Factsheet. July 2024. https://www.energy.gov/sites/default/files/2024-07/lead-tool-factsheet_072624.pdf

Data

In addition to the annual reliability and disconnection data provided for the 2025 Analysis,[3] Consumers also provided reliability and disconnection data for 2025. The updated reliability and disconnection data were used in the regression analyses detailed in subsequent sections. Demographic data was obtained in a similar fashion to the 2025 Analysis, using the MiEJScreen tool and data from the United States Bureau of the Census ("Census Bureau"). These demographic data were used as independent variables in the regression analyses, along with feeder characteristics provided by Consumers. The following subsections detail the different datasets used, highlighting variables and data that are new or different relative to the 2025 Analysis.

2010 Census Tract-Level Data

Reliability Data

Consumers provided annual values of 18 reliability metrics at the 2010 Census-tract level for 2020 through 2025. The reliability data provided was the same as in the 2025 Analysis, but with an additional year of data for 2025. Values of three reliability indices were calculated both with and without Major Event Days ("MEDs"), i.e., days during which "the daily system SAIDI [System Average Interruption Duration Index] exceeds a threshold value."[4]

- Total number of customers interrupted;
- Unique number of customers with an interruption;
- SAIDI excluding MEDs: the total duration of interruption for the average customer during a year,[5] excluding MEDs; expressed in minutes.
- SAIDI including MEDs: the total duration of interruption for the average customer during a year, including MEDs; expressed in minutes.
- System Average Interruption Frequency Index ("SAIFI") excluding MEDs: how often the average customer experiences a sustained interruption during a year, excluding MEDs,[6] expressed in interruptions per customer.
- SAIFI including MEDs: how often the average customer experiences a sustained interruption during a year, including MEDs; expressed in interruptions per customer.

[3] Consumers Energy Company. Rate Case No. U-21870. " Reliability Regression Analysis for Environmental Justice Communities." Exhibit A-135. June 2, 2025. p5.

[4] IEEE Standards Association. (2022). IEEE Guide for Electric Power Distribution Reliability Indices (IEEE Std 1366-2022). The Institute of Electrical and Electronics Engineers, Inc. p20.

[5] IEEE 1366-2022, p15.

[6] *Ibid*.

- Customer Average Interruption Duration Index ("CAIDI") excluding MEDs: the average time to restore service,[7] excluding MEDs; expressed in minutes.
- CAIDI including MEDs: the average time to restore service, including MEDs; expressed in minutes.
- The Customers Experiencing Multiple Interruptions Index ("CEMI-n"), which indicates the percentage of individual customers experiencing n or more sustained interruptions in a year;[8] values were provided for the following metrics:
  - CEMI-4
  - CEMI-5
  - CEMI-7
  - CEMI-10
- The Customers Experiencing Long Interruption Durations Index ("CELID-t"), which indicates the percentage of individual customers that experience a single interruption of at least a given duration, t, in hours;[9] values were provided for the following metrics:
  - CELID-5
  - CELID-24
- The percentage of normal-weather restorations made within 8 hours: Consumers defines normal-weather conditions as those that leave less than 1% of their customers without power.[10]
- The percentage of gray-sky weather restorations made within 24 hours: Consumers defines gray-sky events as those that leave less than 10% of their customers without power.[11]
- The percentage of all-weather restorations made within 36 hours: this category considers restorations made under normal, gray-sky, and catastrophic-weather conditions.
- The percentage of catastrophic-weather restorations made within 48 hours: Consumers defines catastrophic events as those that leave at least 10% of their customers without power.[12]

Demographic Data

The demographic variables and MiEJScreen Overall Score[13] used in the report are identical to those used in the 2025 Analysis.[14] As before, the following demographic variables were extracted from the MiEJScreen Tool:

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[7] IEEE 1366-2022, p15.

[8] *Ibid*, p17.

[9] *Ibid*.

[10] https://www.consumersenergy.com/outages-and-safety/outage-credit

[11] *Ibid*.

[12] *Ibid*.

[13] The MiEJScreen Overall Score is called "MiEJ Score Percentile" in the data available to download through the MiEJScreen: Environmental Justice Screening Tool (Version 1.0) at the following link: https://egle.maps.arcgis.com/apps/webappviewer/index.html?id=b100011f137945138a52a35ec6d8676f

[14] Consumers Energy Company. Rate Case No. U-21870. " Reliability Regression Analysis for Environmental Justice Communities." Exhibit A-135. June 2, 2025. p7.

- Percent Minority Percentile, which is based on "the sum of all race/ethnicity categories except White/Non-Hispanic. It includes Black, American Indian/Alaskan native, Asian, Native Hawaiian-Other Pacific Islander and two or more races." The value of this variable is not the actual percentage of the aforementioned racial/ethnic groups within a census tract's population but rather the census tract's percentile, based on the census tract's rank among the other census tracts in terms of the percentage of its population comprised by Black, Indigenous, and People of Color ("BIPOC");[15]
- Poverty, which is the "percent of population living below two times the federal poverty level";[16]
- Median Household Income in the past 12 months;
- Population Density, in units of 100 people per square mile;
- Percent Unemployed, which is the "percent of the population over the age of 16 that is unemployed and eligible for the labor force."[17] This excludes "retirees, students, homemakers, [and] institutionalized persons."; and
- Housing Burden, which is "the percent of households paying more than 30% of their income on shelter costs."[18]

Urbanized Area and Urban Cluster Data

For details on Urbanized Area ("UA") and Urban Cluster ("UC") data, refer to the 2025 Analysis.[19]

2020 Census Tract-Level Data

Reliability Data

For 2020 through 2025, Consumers provided annual values of the same 18 reliability metrics at the 2020 Census-tract level that they provided at the 2010 Census-tract level.

Residential Involuntary Disconnection Data

Consumers provided annual disconnection counts for 2020 through 2025 for 2020 Census tracts within their service territory. Consumers provided updated disconnection counts for each year from 2020 through 2024, i.e., the disconnection counts in the current study are not the same as

[15] MiEJScreen1.0: Michigan Environmental Justice Mapping and Screening Tool Technical Report, p10.

[16] *Ibid*, p36.

[17] *Ibid*, p41.

[18] *Ibid*, p41.

[19] Consumers Energy Company. Rate Case No. U-21870. " Reliability Regression Analysis for Environmental Justice Communities." Exhibit A-135. June 2, 2025. p7.

those used in the 2025 Analysis.[20] Disconnection rates, in units of disconnections per 1000 households, were calculated at the census-tract level as specified in the following section.

Demographic Data

The Census Bureau provides annual American Community Survey ("ACS") 5-year estimates for demographic variables. The annual ACS 5-year estimates that were used in the 2025 Analysis[21] were also used in this analysis and are shown in Table 1. When the present analysis was carried out, ACS 5-year estimates were available for each year from 2020 through 2024. Because ACS data for 2025 was not available when the present analysis was carried out, disconnection rates were not calculated for 2025 and are therefore not included in this report.

The U.S. Department of Energy's Low-income Energy Affordability Data ("LEAD") Tool tabulates data on average annual energy cost and energy burden. These data have been used in studies assessing correlations between disconnections and demographic characteristics of communities.[22] We used data on Energy Burden (% Income), Electric from the LEAD Tool, which represents the percentage of gross household income spent on the cost of electric energy.[23] This data was tabulated once, i.e., does not vary by year, for 2020 Census tracts.[24]

Table 1. American Community Survey variables used in the study with table codes and descriptions.

ACS Code	Estimate	Table description
B01003_001E	Total	Total Population
B11001_001E	Total Households	Household Type (Including Living Alone)
B03002_003E	Total Not Hispanic or Latino (White alone)	Hispanic or Latino Origin by Race
B19013_001E	Median	Median Household Income in Past 12 months
B17001_001E	Total	Poverty Status in Past 12 Months by Sex by Age
B17001_002E	Total for income in past 12 months below poverty level	Poverty Status in Past 12 Months by Sex by Age

[20] *Ibid*, p8.

[21] *Ibid*, p9.

[22] Memmott, T., Konisky, D.M., and Carley, S. (2024). *Assessing demographic vulnerability and weather impacts on utility disconnections in California*. Nature Communications, Vol. 15:9458. https://doi.org/10.1038/s41467-024-53913-y

[23] U.S. Department of Energy. Low-Income Energy Affordability (LEAD) Tool Fact Sheet. July 2024. https://www.energy.gov/sites/default/files/2024-07/lead-tool-factsheet_072624.pdf

[24] https://www.energy.gov/scep/slsc/lead-tool

ACS Code	Estimate	Table description
B25077_001E	Median	Median Home Value (Dollars)
B23025_005E	Total in Civilian Labor Force Unemployed	Employment Status for Population 16+
B23025_003E	Total in Civilian Labor Force	Employment Status for Population 16+
B25003_001E	Total	Tenure
B25003_003E	Total Renter Occupied	Tenure
B25034_001E	Total	Year Structure Built
B25034_002E	Total Built 2020 or later	Year Structure Built
B25034_003E	Total Built 2010 to 2019	Year Structure Built
B25034_004E	Total Built 2000 to 2009	Year Structure Built
B25034_005E	Total Built 1990 to 1999	Year Structure Built

Table 2. Additional calculated predictor variables and associated American Community Survey reference codes.

Variable	Calculation	ACS Reference
Disconnection Rate	$\frac{\#\ of\ disconnects}{Total\ \#\ of\ Households/1000}$	$\frac{\#\ of\ disconnects}{\text{B11001_001E}}$
Unemployment Rate	$\frac{Unemployed\ Population}{Civilian\ Labor\ Force} \times 100$	$\frac{\text{B23025_005E}}{\text{B23025_003E}} \times 100$
Percentage of Renters	$\frac{Renter - Occupied\ Housing\ Units}{Total\ Occupied\ Housing\ Units} \times 100$	$\frac{\text{B25003_003E}}{\text{B25003_001E}} \times 100$
Percentage of Homes built after 1990	$\frac{Built\ 1990to1999\ +\ 2000to2009\ +2010to2019\ +\ 2020\ or\ later}{Total\ Housing\ Units} \times 100$	$\frac{\text{B25034_005E} + \text{B25034_004E} + \text{B25034_003E} + \text{B25034_002E}}{\text{B25034_001E}} \times 100$
Percent Minority Population	$\left(1 - \frac{Non - Hispanic\ White\ Population}{Census\ Tract\ Population}\right) \times 100$	$\left(1 - \frac{\text{B03002_003E}}{\text{B01003_001E}}\right) \times 100$
Percent Below Poverty Population	$\frac{Population\ Below\ Poverty}{Population\ for\ whom\ Poverty\ Status\ is\ Determined} \times 100$	$\frac{\text{B17001_002E}}{\text{B17001_001E}} \times 100$
Population Density	$\frac{Total\ Households}{Land\ Area}$	$\frac{\text{B11001_001E}}{Land\ Area}$

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Circuit-Level Data

The following sections summarize data provided by Consumers for individual circuits, also called "feeders."

Reliability Data

Consumers provided annual values of the following four reliability metrics for 1943[25] feeders from 2020 through 2025:

- SAIDI excluding MEDs;
- SAIDI including MEDs;
- SAIFI including MEDs; and
- SAIFI excluding MEDs.

Circuit-2010 Census Tract Overlap Data

For each feeder, Consumers provided the percentage of its length that falls within a 2010 Census tract.

Circuit Characteristics Data

Consumers provided data on the following characteristics (the same as specified in the 2025 Analysis[26]) for each feeder:

- Customers per Primary Line Mile;
- Mean Canopy Cover Percentage: the percentage of the land surface covered by trees along the length of a circuit;
- Open Wire Secondary Miles;
- Primary Miles;
- Primary Underground Percentage: the percentage of a feeder's primary line mileage that is underground;
- Voltage: the voltage (kV) and configuration of phases (Delta or Wye Grounded);
- Primary Miles; and
- Year of Last Trim: the year that vegetation proximal to the feeder was most recently trimmed.

[25] In the 2025 Analysis, we stated erroneously on p11 that we used data for 2400 feeders when in fact we used data for 1934 feeders.

[26] Consumers Energy Company. Rate Case No. U-21870. "Reliability Regression Analysis for Environmental Justice Communities". Exhibit A-135. June 2, 2025. p11.

Methods

As discussed in the 2025 Analysis,[27] we used two types of statistical methods to assess whether statistically significant differences are observed in the reliability of different groups of customers within Consumers' service territory. First, the binary difference-in-means *t*-test was applied to assess whether differences in the average reliability of two groups of census tracts were statistically significant. Second, regression models were fitted to assess the magnitude and direction of correlation between the demographic characteristics of a census tract and its reliability, or between the characteristics of a circuit (including both its physical characteristics and the types of communities it serves) and its reliability. The following sections summarize how groups of census tracts were defined, how feeders were classified, and how linear regression models were specified.

Classifying 2010 Census Tracts

2010 Census tracts were classified into the following groups as specified in the 2025 Analysis:[28]

- EJ or Non-EJ;
- Urban or Rural;
- Low Income or High Income; and
- Low Percent Minority Percentile or High Percent Minority Percentile.

Except for the Urban or Rural category, classification was carried out based on MiEJScreen data. Since MiEJScreen data is time-invariant, 2010 Census tracts' classifications do not vary by year.

Classifying 2020 Census Tracts

2020 Census tracts were classified into the following groups as specified in the 2025 Analysis:[29]

- Low Income and High Income; and
- Low Percentage Minority Population and High Percentage Minority Population.

The classification of 2020 Census tracts was carried out based on ACS data, which are provided annually. Therefore, 2020 Census tracts' classifications are assessed annually.

[27] *Ibid*, p12.

[28] *Ibid*, p12-13.

[29] *Ibid*, p13.

Classifying Feeders as Serving a Group of Census Tracts

Feeders were classified as serving groups of 2010 Census tracts as specified in the 2025 Analysis.[30]

Binary Difference-in-Means *t*-test

The binary difference-in-means *t*-test was carried out as specified in the 2025 Analysis.[31]

Linear Regression

We used mixed-effects linear regression to assess how 2010 Census tract-level reliability varies as a function of characteristics of the communities within those census tracts. Our census-tract-level reliability regression models include both time and county-level fixed effects as well as census tract-level random effects and are specified as described in the 2025 Analysis.[32] We also used mixed-effects linear regression to analyze how feeder reliability varies with both physical characteristics of feeders and demographic characteristics of the census tracts served by a feeder. Our feeder-level reliability regression models include both time fixed effects and feeder-level random effects and are specified as in the 2025 Analysis.[33] We used panel linear regression with both time and county-level fixed effects to evaluate relationships between 2020 Census tract-level disconnection rates and characteristics of the communities within those census tracts, as detailed in the 2025 Analysis.[34]

[30] *Ibid*, p13-14.

[31] *Ibid*, p14.

[32] *Ibid*, p16.

[33] *Ibid*, p16-17.

[34] *Ibid*, p15-16.

Descriptive Analysis Results: Reliability

Descriptive Analysis: Average Reliability

The average value of each reliability metric in each year from 2020 through 2025 is shown in Table 3, considering all 1084 census tracts (per the 2010 Census) in Consumers' service territory for which reliability data was available. Tract-level average reliability values for 2020 through 2024 are identical to those reported in the 2025 Analysis.[35] The total number of census tracts in the present analysis differs from the 1050 census tracts included in the 2025 Analysis due to reliability data for additional tracts available in 2025. The values in this table are provided as a reference for the regression coefficients reported and discussed in subsequent sections. For the same reason, the average value of each feeder-level reliability metric in each year from 2020 through 2025 is shown in . Note that feeder-level reliability data are not identical to those reported in the 2025 Analysis as a result of updated data provided by Consumers.

Table 3. The average value (over all 1084 of the 2010 Census tracts in Consumers' service territory for which reliability data was provided) of each 2010 Census-tract-level reliability metric in each year from 2020 through 2025.

Reliability Metric	2020	2021	2022	2023	2024	2025
Unique Customers with an Interruption	1113.87	1211.56	1102.35	1142.70	1088.09	1111.59
Total Customer Interruptions	2363.38	2827.99	2281.05	2452.29	2382.12	2458.24
SAIDI including MEDs	511.22	930.59	447.32	911.41	478.95	968.66
SAIDI excluding MEDs	195.52	239.23	181.27	179.70	160.90	175.61
SAIFI including MEDs	1.32	1.61	1.26	1.38	1.31	1.49
SAIFI excluding MEDs	1.01	1.07	0.96	0.97	0.89	0.92
CAIDI including MEDs	363.92	518.43	345.51	529.50	346.91	567.70
CAIDI excluding MEDs	191.92	211.60	188.66	188.96	182.07	196.66
CEMI-4	0.09	0.13	0.09	0.11	0.11	0.14
CEMI-5	0.05	0.07	0.05	0.05	0.06	0.08
CEMI-7	0.01	0.02	0.01	0.02	0.02	0.02
CEMI-10	0.00	0.00	0.00	0.00	0.00	0.00
CELID-5	0.27	0.39	0.27	0.35	0.29	0.38
CELID-24	0.08	0.16	0.06	0.16	0.07	0.17
Percentage of all-weather restorations made within 36 hours	96.97	94.49	97.88	93.16	97.77	92.34
Percentage of catastrophic-weather restorations made within 48 hours	89.17	79.68	94.05	85.60	95.34	83.89
Percentage of normal-weather restorations made within 8 hours	95.18	93.42	94.45	93.95	94.34	94.08
Percentage of gray-sky-weather restorations made within 24 hours	93.33	89.58	89.37	97.15	94.42	94.71

[35] *Ibid*, p18.

Table 4. The average value (over all feeders in Consumers' distribution system for which reliability data was provided) of each of four feeder-level reliability metrics in each year from 2020 through 2025.

Reliability Metric	2020	2021	2022	2023	2024	2025
SAIDI excluding MEDs	193.65	235.95	184.18	195.9	183.69	196.32
SAIDI including MEDs	535.83	970.7	467.62	1074.43	589.62	957.13
SAIFI excluding MEDs	1.01	1.08	0.94	1.02	1.01	1.05
SAIFI including MEDs	1.33	1.62	1.23	1.47	1.5	1.65

Comparing the Average Reliability of Groups of Census Tracts

To assess whether there were statistically significant differences in the reliability of groups of 2010 Census tracts in Consumers' service territory from 2020 through 2025, we carried out the binary difference-in-means *t*-test. As in the 2025 Analysis,[36] the test was performed for each of the following paired groups of 2010 Census tracts in each year for each reliability metric:

- EJ and Non-EJ;
- Urban and Rural;
- Low Income and High Income; and
- High Percent Minority Percentile and Low Percent Minority Percentile.

The following subsections detail the findings of each set of comparisons.

EJ and Non-EJ Census Tracts

For EJ and Non-EJ census tracts, the results of the binary difference-in-means *t*-test for each reliability metric and each year from 2020 through 2025 are shown in Table 5. The results for 2020 through 2024 are identical to the previously reported results in the 2025 Analysis[37] and are included to facilitate comparison with the results for 2025.

In 2025, statistically significant differences in the mean reliability experienced by EJ and Non-EJ census tracts are observed for Unique Customers with an Interruption and Total Customer Interruptions; SAIDI including MEDs; SAIFI including and excluding MEDs; CEMI-4, -5, and -7; CELID-5; and the percentage of catastrophic-weather restorations made within 48 hours. The percentage of catastrophic-weather restorations made within 48 hours is the only metric by which Non-EJ tracts experienced statistically significant better average reliability, as shown for

[36] *Ibid*, p19.

[37] *Ibid*, p19.

2025 in Table 5. For all other reliability metrics by which a statistically significant difference in average reliability exists, EJ tracts experienced better average reliability.

2025 is the only year in which the difference in the mean SAIDI excluding MEDs of EJ and Non-EJ census tracts is not statistically significant. 2025 is also the only year in which the difference in the mean percentage of catastrophic-weather restorations made within 48 hours between EJ and Non-EJ census tracts is significant. The 2025 Analysis found that for all statistically significant differences, EJ tracts experience better average reliability, but in 2025 Non-EJ tracts experienced better average reliability in terms of the percentage of catastrophic-weather restorations made within 48 hours.

Table 5. Comparison of census-tract-level reliability metrics for each year from 2020 through 2025 averaged for EJ census tracts and for non-EJ census tracts. The difference is calculated by subtracting the EJ Mean from the Non-EJ Mean. Statistical significance is assessed at $\alpha = 0.05$, and the group that experiences better reliability is assessed only for statistically significant differences in mean reliability.

Reliability Metric	Year	Non-EJ Mean	EJ Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.13E+03	8.90E+02	2.37E+02	6.62E-03	TRUE	EJ
	2021	1.23E+03	8.19E+02	4.14E+02	5.55E-07	TRUE	EJ
	2022	1.12E+03	8.52E+02	2.64E+02	2.86E-03	TRUE	EJ
	2023	1.16E+03	8.10E+02	3.52E+02	6.20E-05	TRUE	EJ
	2024	1.10E+03	7.97E+02	3.08E+02	2.97E-04	TRUE	EJ
	2025	1.14E+03	6.75E+02	4.60E+02	2.91E-08	TRUE	EJ
Total Customer Interruptions	2020	2.39E+03	1.82E+03	5.72E+02	1.33E-02	TRUE	EJ
	2021	2.91E+03	1.39E+03	1.52E+03	5.83E-16	TRUE	EJ
	2022	2.31E+03	1.77E+03	5.42E+02	5.06E-02	FALSE	N/A
	2023	2.50E+03	1.56E+03	9.40E+02	3.44E-04	TRUE	EJ
	2024	2.44E+03	1.43E+03	1.01E+03	1.56E-06	TRUE	EJ
	2025	2.53E+03	1.14E+03	1.39E+03	8.49E-13	TRUE	EJ
SAIDI including MEDs	2020	5.24E+02	2.85E+02	2.39E+02	5.69E-05	TRUE	EJ
	2021	9.66E+02	3.06E+02	6.60E+02	3.74E-28	TRUE	EJ
	2022	4.56E+02	2.90E+02	1.66E+02	1.49E-04	TRUE	EJ
	2023	9.36E+02	4.76E+02	4.60E+02	2.50E-05	TRUE	EJ
	2024	4.90E+02	2.89E+02	2.00E+02	1.40E-05	TRUE	EJ
	2025	9.90E+02	5.86E+02	4.03E+02	5.20E-04	TRUE	EJ
SAIDI excluding MEDs	2020	1.99E+02	1.38E+02	6.08E+01	5.05E-05	TRUE	EJ
	2021	2.45E+02	1.34E+02	1.11E+02	3.55E-07	TRUE	EJ
	2022	1.84E+02	1.28E+02	5.60E+01	2.02E-04	TRUE	EJ
	2023	1.84E+02	1.10E+02	7.36E+01	6.37E-10	TRUE	EJ
	2024	1.64E+02	1.06E+02	5.85E+01	5.07E-05	TRUE	EJ
	2025	1.78E+02	1.30E+02	4.85E+01	1.48E-01	FALSE	N/A
SAIFI including MEDs	2020	1.33E+00	1.16E+00	1.75E-01	1.01E-01	FALSE	N/A
	2021	1.65E+00	1.05E+00	5.98E-01	2.69E-08	TRUE	EJ

Reliability Metric	Year	Non-EJ Mean	EJ Mean	Difference	*p*-value	Significant?	Better?
	2022	1.27E+00	1.20E+00	7.19E-02	6.35E-01	FALSE	N/A
	2023	1.40E+00	1.04E+00	3.57E-01	5.60E-03	TRUE	EJ
	2024	1.33E+00	9.16E-01	4.14E-01	1.27E-04	TRUE	EJ
	2025	1.53E+00	8.39E-01	6.91E-01	3.80E-08	TRUE	EJ
SAIFI excluding MEDs	2020	1.01E+00	9.36E-01	7.63E-02	4.32E-01	FALSE	N/A
	2021	1.09E+00	7.92E-01	2.93E-01	1.41E-03	TRUE	EJ
	2022	9.61E-01	8.85E-01	7.55E-02	4.25E-01	FALSE	N/A
	2023	9.76E-01	7.85E-01	1.91E-01	2.75E-02	TRUE	EJ
	2024	9.03E-01	6.90E-01	2.13E-01	1.78E-02	TRUE	EJ
	2025	9.37E-01	5.97E-01	3.40E-01	9.85E-04	TRUE	EJ
CAIDI including MEDs	2020	3.71E+02	2.30E+02	1.41E+02	9.12E-07	TRUE	EJ
	2021	5.30E+02	3.16E+02	2.14E+02	8.10E-08	TRUE	EJ
	2022	3.49E+02	2.76E+02	7.30E+01	2.81E-03	TRUE	EJ
	2023	5.36E+02	4.09E+02	1.28E+02	5.02E-02	FALSE	N/A
	2024	3.49E+02	3.17E+02	3.15E+01	2.61E-01	FALSE	N/A
	2025	5.63E+02	6.57E+02	-9.37E+01	3.30E-01	FALSE	N/A
CAIDI excluding MEDs	2020	1.94E+02	1.63E+02	3.03E+01	3.64E-03	TRUE	EJ
	2021	2.14E+02	1.77E+02	3.66E+01	2.09E-02	TRUE	EJ
	2022	1.90E+02	1.64E+02	2.58E+01	1.85E-02	TRUE	EJ
	2023	1.90E+02	1.75E+02	1.43E+01	3.57E-01	FALSE	N/A
	2024	1.83E+02	1.64E+02	1.91E+01	1.22E-01	FALSE	N/A
	2025	1.97E+02	1.98E+02	-1.12E+00	9.56E-01	FALSE	N/A
CEMI-4	2020	9.27E-02	6.30E-02	2.97E-02	1.14E-01	FALSE	N/A
	2021	1.35E-01	3.33E-02	1.02E-01	7.35E-17	TRUE	EJ
	2022	9.26E-02	8.33E-02	9.27E-03	7.09E-01	FALSE	N/A
	2023	1.09E-01	6.48E-02	4.46E-02	4.68E-02	TRUE	EJ
	2024	1.11E-01	4.29E-02	6.79E-02	2.01E-05	TRUE	EJ
	2025	1.40E-01	4.51E-02	9.50E-02	5.81E-06	TRUE	EJ
CEMI-5	2020	4.68E-02	3.19E-02	1.50E-02	2.71E-01	FALSE	N/A
	2021	7.55E-02	1.09E-02	6.47E-02	8.31E-23	TRUE	EJ
	2022	4.59E-02	4.29E-02	3.05E-03	8.66E-01	FALSE	N/A
	2023	5.56E-02	3.07E-02	2.49E-02	6.01E-02	FALSE	N/A
	2024	6.28E-02	1.73E-02	4.54E-02	7.17E-08	TRUE	EJ
	2025	7.94E-02	2.41E-02	5.54E-02	1.98E-04	TRUE	EJ
CEMI-7	2020	1.25E-02	3.78E-03	8.75E-03	6.95E-04	TRUE	EJ
	2021	2.09E-02	1.28E-04	2.07E-02	5.36E-21	TRUE	EJ
	2022	9.95E-03	9.26E-03	6.86E-04	9.14E-01	FALSE	N/A
	2023	1.60E-02	3.88E-03	1.22E-02	2.29E-05	TRUE	EJ
	2024	1.97E-02	1.69E-03	1.80E-02	2.54E-15	TRUE	EJ
	2025	2.58E-02	1.73E-03	2.41E-02	5.09E-15	TRUE	EJ
CEMI-10	2020	2.92E-03	1.00E-04	2.82E-03	1.14E-02	TRUE	EJ

Reliability Metric	Year	Non-EJ Mean	EJ Mean	Difference	*p*-value	Significant?	Better?
	2021	2.22E-03	0.00E+00	2.22E-03	5.07E-07	TRUE	EJ
	2022	1.43E-03	5.04E-05	1.38E-03	6.36E-03	TRUE	EJ
	2023	2.32E-03	9.52E-06	2.31E-03	9.66E-06	TRUE	EJ
	2024	4.79E-03	1.30E-05	4.77E-03	3.99E-05	TRUE	EJ
	2025	4.99E-03	0.00E+00	4.99E-03	1.26E-05	TRUE	EJ
CELID-5	2020	2.77E-01	1.71E-01	1.06E-01	1.66E-03	TRUE	EJ
	2021	4.03E-01	2.08E-01	1.95E-01	1.20E-07	TRUE	EJ
	2022	2.77E-01	2.16E-01	6.09E-02	4.16E-02	TRUE	EJ
	2023	3.58E-01	2.24E-01	1.35E-01	7.58E-04	TRUE	EJ
	2024	3.00E-01	1.95E-01	1.05E-01	2.94E-04	TRUE	EJ
	2025	3.82E-01	2.56E-01	1.27E-01	1.23E-03	TRUE	EJ
CELID-24	2020	8.20E-02	3.83E-02	4.37E-02	1.47E-02	TRUE	EJ
	2021	1.66E-01	3.00E-02	1.36E-01	1.17E-25	TRUE	EJ
	2022	6.15E-02	3.39E-02	2.76E-02	1.70E-02	TRUE	EJ
	2023	1.68E-01	8.74E-02	8.06E-02	9.36E-04	TRUE	EJ
	2024	7.17E-02	5.51E-02	1.66E-02	2.69E-01	FALSE	N/A
	2025	1.78E-01	1.23E-01	5.41E-02	5.47E-02	FALSE	N/A
Percentage of all-weather restorations made within 36 hours	2020	9.69E+01	9.91E+01	-2.21E+00	1.44E-04	TRUE	EJ
	2021	9.44E+01	9.70E+01	-2.62E+00	3.21E-02	TRUE	EJ
	2022	9.78E+01	9.96E+01	-1.81E+00	1.98E-11	TRUE	EJ
	2023	9.30E+01	9.55E+01	-2.44E+00	8.37E-02	FALSE	N/A
	2024	9.77E+01	9.89E+01	-1.21E+00	3.95E-02	TRUE	EJ
	2025	9.26E+01	8.75E+01	5.14E+00	7.07E-02	FALSE	N/A
Percentage of catastrophic-weather restorations made within 48 hours	2020	8.92E+01	8.87E+01	5.32E-01	9.01E-01	FALSE	N/A
	2021	7.95E+01	8.25E+01	-2.94E+00	5.22E-01	FALSE	N/A
	2022	9.40E+01	9.52E+01	-1.20E+00	7.43E-01	FALSE	N/A
	2023	8.56E+01	8.51E+01	5.57E-01	9.04E-01	FALSE	N/A
	2024	9.54E+01	9.49E+01	4.41E-01	8.28E-01	FALSE	N/A
	2025	8.46E+01	7.03E+01	1.43E+01	5.58E-03	TRUE	Non-EJ
Percentage of normal-weather restorations made within 8 hours	2020	9.52E+01	9.48E+01	4.25E-01	8.30E-01	FALSE	N/A
	2021	9.34E+01	9.43E+01	-9.71E-01	5.37E-01	FALSE	N/A
	2022	9.46E+01	9.25E+01	2.04E+00	2.76E-01	FALSE	N/A
	2023	9.40E+01	9.25E+01	1.51E+00	5.27E-01	FALSE	N/A
	2024	9.42E+01	9.60E+01	-1.71E+00	1.89E-01	FALSE	N/A
	2025	9.40E+01	9.55E+01	-1.47E+00	2.74E-01	FALSE	N/A
Percentage of gray-sky-weather restorations made within 24 hours	2020	9.30E+01	9.91E+01	-6.15E+00	1.03E-16	TRUE	EJ
	2021	8.93E+01	9.56E+01	-6.39E+00	4.88E-05	TRUE	EJ
	2022	8.94E+01	8.96E+01	-2.50E-01	9.33E-01	FALSE	N/A
	2023	9.73E+01	9.43E+01	2.98E+00	2.80E-01	FALSE	N/A
	2024	9.45E+01	9.32E+01	1.25E+00	6.96E-01	FALSE	N/A
	2025	9.47E+01	9.44E+01	2.91E-01	9.14E-01	FALSE	N/A

Urban and Rural Census Tracts

For Urban and Rural census tracts, the results of the binary difference-in-means *t*-test for each reliability metric and each year from 2020 through 2025 are shown in Table 6. The results for 2020 through 2024 are identical to the results of the 2025 Analysis and are included to facilitate comparison with results for 2025.[38]

For 2025, statistically significant differences in the mean reliability experienced by Urban and Rural census tracts are observed for Unique Customers with an Interruption; Total Customer Interruptions; SAIDI and SAIFI (each excluding and including MEDs); CAIDI excluding MEDs; CEMI-4, -5, -7, and -10; CELID-5 and -24; the percentage of catastrophic-weather restorations made within 48 hours; and the percentage of normal-weather restorations made within 8 hours. The percentage of catastrophic-weather restorations made within 48 hours in 2025 is the only metric by which Rural tracts experienced better average reliability. By all other metrics, Urban tracts consistently experienced better average reliability.

Table 6. Comparison of census-tract-level reliability metrics for each year from 2020 through 2025 averaged for Rural census tracts and for Urban census tracts. Significance is assessed at α = 0.05.

Reliability Metric	Year	Rural Mean	Urban Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.24E+03	9.41E+02	3.03E+02	1.30E-11	TRUE	Urban
	2021	1.37E+03	1.01E+03	3.58E+02	7.08E-14	TRUE	Urban
	2022	1.22E+03	9.51E+02	2.65E+02	1.57E-08	TRUE	Urban
	2023	1.24E+03	1.01E+03	2.32E+02	1.89E-06	TRUE	Urban
	2024	1.22E+03	9.15E+02	3.04E+02	1.53E-10	TRUE	Urban
	2025	1.26E+03	9.16E+02	3.43E+02	2.09E-12	TRUE	Urban
Total Customer Interruptions	2020	2.91E+03	1.64E+03	1.28E+03	2.32E-25	TRUE	Urban
	2021	3.66E+03	1.72E+03	1.94E+03	1.57E-43	TRUE	Urban
	2022	2.76E+03	1.65E+03	1.11E+03	9.54E-20	TRUE	Urban
	2023	2.93E+03	1.82E+03	1.11E+03	2.21E-17	TRUE	Urban
	2024	2.99E+03	1.57E+03	1.42E+03	9.00E-25	TRUE	Urban
	2025	3.20E+03	1.47E+03	1.74E+03	2.90E-34	TRUE	Urban
SAIDI including MEDs	2020	6.65E+02	3.07E+02	3.58E+02	6.84E-23	TRUE	Urban
	2021	1.35E+03	3.80E+02	9.65E+02	4.73E-55	TRUE	Urban
	2022	5.86E+02	2.63E+02	3.23E+02	3.78E-36	TRUE	Urban
	2023	1.13E+03	6.24E+02	5.05E+02	1.08E-09	TRUE	Urban
	2024	6.20E+02	2.91E+02	3.29E+02	2.51E-21	TRUE	Urban
	2025	1.30E+03	5.28E+02	7.72E+02	8.48E-22	TRUE	Urban
SAIDI excluding MEDs	2020	2.49E+02	1.25E+02	1.24E+02	1.63E-26	TRUE	Urban
	2021	3.15E+02	1.38E+02	1.77E+02	2.66E-31	TRUE	Urban
	2022	2.30E+02	1.16E+02	1.14E+02	2.19E-31	TRUE	Urban

[38] *Ibid*, p22.

Reliability Metric	Year	Rural Mean	Urban Mean	Difference	*p*-value	Significant?	Better?
	2023	2.18E+02	1.30E+02	8.81E+01	9.70E-20	TRUE	Urban
	2024	2.08E+02	9.83E+01	1.10E+02	1.04E-30	TRUE	Urban
	2025	2.32E+02	1.01E+02	1.31E+02	2.04E-32	TRUE	Urban
SAIFI including MEDs	2020	1.62E+00	9.26E-01	6.96E-01	2.67E-34	TRUE	Urban
	2021	2.09E+00	9.90E-01	1.10E+00	1.21E-67	TRUE	Urban
	2022	1.53E+00	9.17E-01	6.09E-01	4.10E-30	TRUE	Urban
	2023	1.62E+00	1.05E+00	5.69E-01	2.66E-21	TRUE	Urban
	2024	1.63E+00	8.77E-01	7.55E-01	1.01E-34	TRUE	Urban
	2025	1.96E+00	8.69E-01	1.10E+00	6.45E-57	TRUE	Urban
SAIFI excluding MEDs	2020	1.20E+00	7.50E-01	4.53E-01	9.05E-23	TRUE	Urban
	2021	1.32E+00	7.43E-01	5.73E-01	9.28E-36	TRUE	Urban
	2022	1.15E+00	7.05E-01	4.42E-01	8.53E-26	TRUE	Urban
	2023	1.13E+00	7.53E-01	3.75E-01	3.10E-18	TRUE	Urban
	2024	1.11E+00	6.07E-01	4.99E-01	1.18E-29	TRUE	Urban
	2025	1.18E+00	5.67E-01	6.18E-01	1.63E-41	TRUE	Urban
CAIDI including MEDs	2020	3.88E+02	3.32E+02	5.54E+01	6.51E-03	TRUE	Urban
	2021	6.14E+02	3.92E+02	2.22E+02	6.14E-21	TRUE	Urban
	2022	3.83E+02	2.96E+02	8.61E+01	3.26E-08	TRUE	Urban
	2023	5.44E+02	5.11E+02	3.30E+01	3.29E-01	FALSE	N/A
	2024	3.52E+02	3.40E+02	1.26E+01	4.29E-01	FALSE	N/A
	2025	5.83E+02	5.47E+02	3.64E+01	2.57E-01	FALSE	N/A
CAIDI excluding MEDs	2020	2.01E+02	1.80E+02	2.03E+01	6.86E-03	TRUE	Urban
	2021	2.29E+02	1.88E+02	4.10E+01	1.11E-06	TRUE	Urban
	2022	2.00E+02	1.74E+02	2.61E+01	8.15E-07	TRUE	Urban
	2023	1.97E+02	1.78E+02	1.90E+01	1.37E-03	TRUE	Urban
	2024	1.91E+02	1.71E+02	2.02E+01	1.83E-04	TRUE	Urban
	2025	2.04E+02	1.87E+02	1.71E+01	4.67E-02	TRUE	Urban
CEMI-4	2020	1.32E-01	3.65E-02	9.58E-02	5.75E-30	TRUE	Urban
	2021	2.01E-01	3.58E-02	1.65E-01	1.60E-61	TRUE	Urban
	2022	1.29E-01	4.32E-02	8.58E-02	4.83E-25	TRUE	Urban
	2023	1.47E-01	5.42E-02	9.27E-02	2.08E-21	TRUE	Urban
	2024	1.55E-01	4.33E-02	1.12E-01	3.90E-33	TRUE	Urban
	2025	2.10E-01	3.61E-02	1.73E-01	3.86E-50	TRUE	Urban
CEMI-5	2020	7.10E-02	1.29E-02	5.81E-02	4.71E-25	TRUE	Urban
	2021	1.16E-01	1.38E-02	1.02E-01	4.47E-42	TRUE	Urban
	2022	6.58E-02	1.93E-02	4.65E-02	1.14E-17	TRUE	Urban
	2023	7.96E-02	2.10E-02	5.87E-02	7.33E-21	TRUE	Urban
	2024	9.18E-02	1.86E-02	7.31E-02	2.88E-27	TRUE	Urban
	2025	1.23E-01	1.46E-02	1.08E-01	3.60E-35	TRUE	Urban
CEMI-7	2020	2.01E-02	1.39E-03	1.87E-02	2.46E-11	TRUE	Urban
	2021	3.20E-02	3.54E-03	2.84E-02	1.04E-13	TRUE	Urban
	2022	1.51E-02	3.03E-03	1.21E-02	5.86E-08	TRUE	Urban

Reliability Metric	Year	Rural Mean	Urban Mean	Difference	*p*-value	Significant?	Better?
	2023	2.52E-02	2.49E-03	2.27E-02	3.04E-13	TRUE	Urban
	2024	2.96E-02	4.40E-03	2.52E-02	4.74E-12	TRUE	Urban
	2025	4.21E-02	1.36E-03	4.07E-02	2.95E-17	TRUE	Urban
CEMI-10	2020	4.83E-03	5.11E-05	4.78E-03	9.64E-03	TRUE	Urban
	2021	3.68E-03	3.39E-06	3.67E-03	4.79E-07	TRUE	Urban
	2022	2.37E-03	1.39E-05	2.36E-03	4.79E-03	TRUE	Urban
	2023	3.84E-03	2.25E-05	3.81E-03	1.03E-05	TRUE	Urban
	2024	6.01E-03	2.57E-03	3.44E-03	1.39E-01	FALSE	N/A
	2025	8.27E-03	3.82E-05	8.23E-03	1.40E-05	TRUE	Urban
CELID-5	2020	3.42E-01	1.77E-01	1.65E-01	4.14E-26	TRUE	Urban
	2021	5.11E-01	2.35E-01	2.76E-01	4.80E-58	TRUE	Urban
	2022	3.33E-01	1.94E-01	1.39E-01	8.27E-21	TRUE	Urban
	2023	3.98E-01	2.89E-01	1.09E-01	2.36E-08	TRUE	Urban
	2024	3.58E-01	2.11E-01	1.47E-01	6.75E-19	TRUE	Urban
	2025	4.83E-01	2.33E-01	2.50E-01	3.75E-43	TRUE	Urban
CELID-24	2020	1.06E-01	4.51E-02	6.07E-02	7.02E-11	TRUE	Urban
	2021	2.39E-01	5.33E-02	1.85E-01	5.01E-52	TRUE	Urban
	2022	8.23E-02	3.06E-02	5.18E-02	2.57E-15	TRUE	Urban
	2023	1.92E-01	1.27E-01	6.53E-02	4.35E-05	TRUE	Urban
	2024	9.03E-02	4.50E-02	4.53E-02	2.25E-07	TRUE	Urban
	2025	2.19E-01	1.16E-01	1.03E-01	8.68E-12	TRUE	Urban
Percentage of all-weather restorations made within 36 hours	2020	9.70E+01	9.69E+01	1.73E-01	7.47E-01	FALSE	N/A
	2021	9.28E+01	9.68E+01	-4.04E+00	5.62E-13	TRUE	Urban
	2022	9.71E+01	9.89E+01	-1.75E+00	2.09E-06	TRUE	Urban
	2023	9.32E+01	9.32E+01	-2.32E-03	9.98E-01	FALSE	N/A
	2024	9.77E+01	9.79E+01	-1.53E-01	7.26E-01	FALSE	N/A
	2025	9.28E+01	9.17E+01	1.06E+00	2.26E-01	FALSE	N/A
Percentage of catastrophic-weather restorations made within 48 hours	2020	9.03E+01	8.75E+01	2.88E+00	7.13E-02	FALSE	N/A
	2021	7.87E+01	8.12E+01	-2.54E+00	1.98E-01	FALSE	N/A
	2022	9.37E+01	9.46E+01	-8.67E-01	5.46E-01	FALSE	N/A
	2023	8.59E+01	8.51E+01	8.30E-01	6.34E-01	FALSE	N/A
	2024	9.57E+01	9.48E+01	8.55E-01	3.96E-01	FALSE	N/A
	2025	8.56E+01	8.15E+01	4.05E+00	1.81E-02	TRUE	Rural
Percentage of normal-weather restorations made within 8 hours	2020	9.50E+01	9.55E+01	-4.98E-01	4.48E-01	FALSE	N/A
	2021	9.30E+01	9.40E+01	-1.05E+00	1.41E-01	FALSE	N/A
	2022	9.49E+01	9.39E+01	9.36E-01	2.16E-01	FALSE	N/A
	2023	9.43E+01	9.35E+01	7.59E-01	3.33E-01	FALSE	N/A
	2024	9.43E+01	9.44E+01	-1.36E-01	8.61E-01	FALSE	N/A
	2025	9.35E+01	9.49E+01	-1.43E+00	4.19E-02	TRUE	Urban
Percentage of gray-sky-weather restorations made within 24 hours	2020	9.23E+01	9.47E+01	-2.39E+00	2.24E-02	TRUE	Urban
	2021	8.99E+01	8.91E+01	8.55E-01	4.95E-01	FALSE	N/A
	2022	8.78E+01	9.15E+01	-3.70E+00	2.79E-03	TRUE	Urban

Reliability Metric	Year	Rural Mean	Urban Mean	Difference	*p*-value	Significant?	Better?
	2023	9.75E+01	9.65E+01	9.79E-01	2.69E-01	FALSE	N/A
	2024	9.40E+01	9.50E+01	-9.69E-01	3.49E-01	FALSE	N/A
	2025	9.46E+01	9.49E+01	-2.43E-01	8.13E-01	FALSE	N/A

Low-Income and High-Income Census Tracts

For Low-Income and High-Income census tracts, the results of the binary difference-in-means *t*-test for each reliability metric and each year from 2020 through 2025 are shown in Table 7. The results for 2020 through 2024 are identical to the results of the 2025 Analysis.[39] In 2025, statistically significant differences in the mean reliability experienced by Low-Income and High-Income census tracts were observed in terms of Unique Customers with an Interruption and Total Customer Interruptions; SAIDI and SAIFI, each including and excluding MEDs; CAIDI including MEDs; CEMI-4, -5, -7, and -10; CELID-5; the percentage of all-weather restorations made within 36 hours and the percentage of catastrophic-weather restorations made within 48 hours. For CAIDI including MEDs, the percentage of all-weather restorations made within 36 hours, and the percentage of catastrophic-weather restorations made within 48 hours, High-Income tracts experienced better average reliability in 2025. By all other metrics, Low-Income tracts experienced better average reliability in 2025. There are no statistically significant differences between the average reliability of High-Income and Low-Income tracts for any year in terms of CAIDI excluding MEDs, the percentage of normal-weather restorations made within 8 hours, or the percentage of gray-sky-weather restorations made within 24 hours.

With respect to the results of the 2025 Analysis, a similar trend is observed in the present analysis: for all but three reliability metrics, Low-Income tracts experienced better average reliability in 2025. Two of the three metrics by which High-Income tracts were previously found to have experienced better average reliability are the same in the current analysis: the percentage of all-weather restorations made within 36 hours (in 2020), and the percentage of catastrophic-weather restorations made within 48 hours (in 2020 and 2024).

Table 7. Comparison of census-tract-level reliability metrics for each year from 2020 through 2025 averaged for High-Income census tracts and for Low-Income census tracts. Significance is assessed at α = 0.05.

Reliability Metric	Year	High-Income Mean	Low-Income Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.16E+03	6.83E+02	4.79E+02	5.98E-13	TRUE	Low
	2021	1.26E+03	7.75E+02	4.85E+02	8.84E-13	TRUE	Low
	2022	1.15E+03	6.50E+02	5.03E+02	6.21E-12	TRUE	Low
	2023	1.19E+03	7.04E+02	4.88E+02	2.89E-12	TRUE	Low
	2024	1.14E+03	5.93E+02	5.50E+02	1.19E-15	TRUE	Low

[39] *Ibid*, p25.

Reliability Metric	Year	High-Income Mean	Low-Income Mean	Difference	*p*-value	Significant?	Better?
	2025	1.16E+03	6.96E+02	4.61E+02	1.01E-09	TRUE	Low
Total Customer Interruptions	2020	2.48E+03	1.31E+03	1.17E+03	1.29E-10	TRUE	Low
	2021	2.97E+03	1.59E+03	1.37E+03	4.72E-09	TRUE	Low
	2022	2.41E+03	1.11E+03	1.30E+03	5.53E-15	TRUE	Low
	2023	2.59E+03	1.25E+03	1.34E+03	1.61E-16	TRUE	Low
	2024	2.51E+03	1.25E+03	1.26E+03	5.68E-06	TRUE	Low
	2025	2.59E+03	1.28E+03	1.31E+03	4.82E-10	TRUE	Low
SAIDI including MEDs	2020	5.27E+02	3.71E+02	1.56E+02	1.96E-03	TRUE	Low
	2021	9.85E+02	4.49E+02	5.36E+02	1.60E-15	TRUE	Low
	2022	4.68E+02	2.58E+02	2.10E+02	3.05E-10	TRUE	Low
	2023	9.58E+02	5.00E+02	4.58E+02	7.43E-06	TRUE	Low
	2024	4.98E+02	3.06E+02	1.92E+02	5.31E-03	TRUE	Low
	2025	1.00E+03	6.74E+02	3.27E+02	9.28E-04	TRUE	Low
SAIDI excluding MEDs	2020	2.03E+02	1.32E+02	7.11E+01	1.28E-06	TRUE	Low
	2021	2.45E+02	1.85E+02	5.99E+01	1.19E-03	TRUE	Low
	2022	1.86E+02	1.42E+02	4.34E+01	7.56E-03	TRUE	Low
	2023	1.85E+02	1.33E+02	5.17E+01	6.58E-04	TRUE	Low
	2024	1.66E+02	1.18E+02	4.82E+01	4.16E-03	TRUE	Low
	2025	1.82E+02	1.14E+02	6.89E+01	4.39E-04	TRUE	Low
SAIFI including MEDs	2020	1.37E+00	9.33E-01	4.33E-01	1.47E-07	TRUE	Low
	2021	1.66E+00	1.21E+00	4.47E-01	2.19E-05	TRUE	Low
	2022	1.31E+00	8.39E-01	4.72E-01	1.62E-09	TRUE	Low
	2023	1.42E+00	9.78E-01	4.45E-01	2.18E-07	TRUE	Low
	2024	1.36E+00	8.26E-01	5.35E-01	1.04E-06	TRUE	Low
	2025	1.56E+00	9.29E-01	6.27E-01	1.70E-11	TRUE	Low
SAIFI excluding MEDs	2020	1.04E+00	7.09E-01	3.33E-01	3.16E-06	TRUE	Low
	2021	1.08E+00	9.39E-01	1.46E-01	7.68E-02	FALSE	N/A
	2022	9.83E-01	7.19E-01	2.64E-01	6.92E-05	TRUE	Low
	2023	9.89E-01	7.64E-01	2.25E-01	1.05E-03	TRUE	Low
	2024	9.25E-01	5.98E-01	3.27E-01	8.26E-07	TRUE	Low
	2025	9.55E-01	5.93E-01	3.63E-01	3.12E-07	TRUE	Low
CAIDI including MEDs	2020	3.56E+02	4.33E+02	-7.68E+01	9.30E-02	FALSE	N/A
	2021	5.29E+02	4.21E+02	1.08E+02	7.77E-03	TRUE	Low
	2022	3.49E+02	3.13E+02	3.59E+01	2.81E-01	FALSE	N/A
	2023	5.42E+02	4.15E+02	1.28E+02	1.31E-02	TRUE	Low
	2024	3.45E+02	3.67E+02	-2.25E+01	5.06E-01	FALSE	N/A
	2025	5.50E+02	7.26E+02	-1.76E+02	2.09E-02	TRUE	High
CAIDI excluding MEDs	2020	1.91E+02	2.04E+02	-1.36E+01	3.29E-01	FALSE	N/A
	2021	2.11E+02	2.17E+02	-6.03E+00	6.85E-01	FALSE	N/A
	2022	1.88E+02	1.99E+02	-1.11E+01	2.62E-01	FALSE	N/A
	2023	1.90E+02	1.81E+02	9.17E+00	3.32E-01	FALSE	N/A

Reliability Metric	Year	High-Income Mean	Low-Income Mean	Difference	*p*-value	Significant?	Better?
	2024	1.81E+02	1.94E+02	-1.36E+01	1.89E-01	FALSE	N/A
	2025	1.96E+02	2.06E+02	-1.03E+01	4.68E-01	FALSE	N/A
CEMI-4	2020	9.65E-02	4.37E-02	5.28E-02	7.02E-06	TRUE	Low
	2021	1.37E-01	6.25E-02	7.49E-02	2.31E-06	TRUE	Low
	2022	9.86E-02	3.34E-02	6.52E-02	3.94E-13	TRUE	Low
	2023	1.14E-01	4.70E-02	6.67E-02	2.86E-08	TRUE	Low
	2024	1.15E-01	4.13E-02	7.32E-02	4.00E-08	TRUE	Low
	2025	1.45E-01	4.70E-02	9.78E-02	6.17E-10	TRUE	Low
CEMI-5	2020	4.89E-02	2.05E-02	2.84E-02	1.77E-04	TRUE	Low
	2021	7.66E-02	3.15E-02	4.52E-02	6.90E-05	TRUE	Low
	2022	4.95E-02	1.20E-02	3.75E-02	2.93E-13	TRUE	Low
	2023	5.85E-02	1.70E-02	4.15E-02	7.42E-12	TRUE	Low
	2024	6.48E-02	2.07E-02	4.40E-02	3.64E-05	TRUE	Low
	2025	8.25E-02	2.19E-02	6.07E-02	2.91E-08	TRUE	Low
CEMI-7	2020	1.31E-02	2.87E-03	1.02E-02	1.77E-06	TRUE	Low
	2021	2.14E-02	5.11E-03	1.63E-02	1.93E-05	TRUE	Low
	2022	1.09E-02	9.28E-04	9.98E-03	2.08E-11	TRUE	Low
	2023	1.69E-02	2.21E-03	1.47E-02	2.32E-11	TRUE	Low
	2024	1.98E-02	9.38E-03	1.04E-02	1.67E-01	FALSE	N/A
	2025	2.70E-02	3.01E-03	2.39E-02	9.39E-12	TRUE	Low
CEMI-10	2020	3.06E-03	2.34E-04	2.83E-03	1.71E-02	TRUE	Low
	2021	2.31E-03	1.76E-04	2.14E-03	1.36E-05	TRUE	Low
	2022	1.51E-03	2.64E-05	1.48E-03	5.29E-03	TRUE	Low
	2023	2.44E-03	5.03E-06	2.43E-03	9.20E-06	TRUE	Low
	2024	4.59E-03	4.03E-03	5.56E-04	8.93E-01	FALSE	N/A
	2025	5.24E-03	1.16E-04	5.13E-03	2.21E-05	TRUE	Low
CELID-5	2020	2.80E-01	1.94E-01	8.67E-02	2.21E-04	TRUE	Low
	2021	4.05E-01	2.81E-01	1.24E-01	1.40E-05	TRUE	Low
	2022	2.83E-01	1.90E-01	9.31E-02	1.70E-04	TRUE	Low
	2023	3.65E-01	2.28E-01	1.37E-01	1.17E-06	TRUE	Low
	2024	3.08E-01	1.75E-01	1.32E-01	5.85E-08	TRUE	Low
	2025	3.89E-01	2.60E-01	1.29E-01	5.07E-06	TRUE	Low
CELID-24	2020	8.12E-02	6.62E-02	1.50E-02	3.12E-01	FALSE	N/A
	2021	1.70E-01	6.32E-02	1.07E-01	5.03E-14	TRUE	Low
	2022	6.24E-02	3.89E-02	2.35E-02	2.43E-02	TRUE	Low
	2023	1.73E-01	8.49E-02	8.77E-02	2.79E-05	TRUE	Low
	2024	7.38E-02	4.42E-02	2.96E-02	1.37E-02	TRUE	Low
	2025	1.78E-01	1.42E-01	3.60E-02	1.21E-01	FALSE	N/A
Percentage of all-weather restorations made within 36 hours	2020	9.73E+01	9.44E+01	2.88E+00	3.33E-02	TRUE	High
	2021	9.44E+01	9.57E+01	-1.34E+00	1.77E-01	FALSE	N/A
	2022	9.79E+01	9.81E+01	-2.49E-01	7.86E-01	FALSE	N/A

Reliability Metric	Year	High-Income Mean	Low-Income Mean	Difference	*p*-value	Significant?	Better?
	2023	9.29E+01	9.51E+01	-2.16E+00	6.95E-02	FALSE	N/A
	2024	9.79E+01	9.70E+01	9.07E-01	3.92E-01	FALSE	N/A
	2025	9.30E+01	8.63E+01	6.75E+00	2.18E-03	TRUE	High
Percentage of catastrophic-weather restorations made within 48 hours	2020	9.02E+01	7.97E+01	1.04E+01	2.53E-03	TRUE	High
	2021	7.99E+01	7.75E+01	2.42E+00	5.09E-01	FALSE	N/A
	2022	9.39E+01	9.59E+01	-2.05E+00	3.59E-01	FALSE	N/A
	2023	8.57E+01	8.42E+01	1.55E+00	6.63E-01	FALSE	N/A
	2024	9.58E+01	9.04E+01	5.40E+00	4.10E-02	TRUE	High
	2025	8.49E+01	7.42E+01	1.07E+01	2.37E-03	TRUE	High
Percentage of normal-weather restorations made within 8 hours	2020	9.52E+01	9.47E+01	5.63E-01	6.50E-01	FALSE	N/A
	2021	9.34E+01	9.34E+01	3.37E-02	9.80E-01	FALSE	N/A
	2022	9.45E+01	9.44E+01	2.02E-02	9.84E-01	FALSE	N/A
	2023	9.40E+01	9.33E+01	7.77E-01	5.28E-01	FALSE	N/A
	2024	9.46E+01	9.19E+01	2.71E+00	1.18E-01	FALSE	N/A
	2025	9.42E+01	9.32E+01	9.49E-01	4.18E-01	FALSE	N/A
Percentage of gray-sky-weather restorations made within 24 hours	2020	9.34E+01	9.24E+01	1.00E+00	5.84E-01	FALSE	N/A
	2021	8.97E+01	8.82E+01	1.48E+00	5.05E-01	FALSE	N/A
	2022	8.97E+01	8.63E+01	3.38E+00	1.96E-01	FALSE	N/A
	2023	9.76E+01	9.26E+01	4.96E+00	5.50E-02	FALSE	N/A
	2024	9.45E+01	9.41E+01	3.45E-01	8.62E-01	FALSE	N/A
	2025	9.49E+01	9.24E+01	2.56E+00	2.69E-01	FALSE	N/A

High-Percent-Minority-Percentile and Low Percent-Minority-Percentile Census Tracts

For Low-Percent-Minority-Percentile and High-Percent-Minority-Percentile census tracts, the results of the binary difference-in-means *t*-test for each reliability metric and each year from 2020 through 2025 are shown in Table 8. In 2025, statistically significant differences in the mean reliability experienced by Low-Percent-Minority-Percentile and High-Percent-Minority-Percentile census tracts are observed for Unique Customers with an Interruption and Total Customer Interruptions; SAIDI and SAIFI (each excluding and including MEDs); CAIDI including MEDs; CEMI-4, -5, -7, and -10; CELID-5; the percentage of all-weather restorations made within 36 hours; and the percentage of catastrophic-weather restorations made within 48 hours. In 2025, Low-Percent-Minority-Percentile tracts experienced better average reliability than High-Percent-Minority-Percentile tracts in terms of CAIDI including MEDs, the percentage of all-weather restorations made within 36 hours, and the percentage of catastrophic-weather restorations made within 48 hours. By all other reliability metrics, High-Percent-Minority-Percentile tracts experienced better average reliability in 2025. In general, when statistically significant differences in the average reliability of the two groups exist, High-Percent-Minority-Percentile tracts experience better average reliability. Except for the three metrics previously

noted in 2025, the only other instance where Low-Percent-Minority-Percentile tracts had better average reliability is in terms of the percentage of catastrophic-weather restorations made within 48 hours in 2020. There are no statistically significant differences among High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile tracts for any year for the percentage of normal-weather restorations made within 8 hours or the percentage of gray-sky-weather restorations made within 24 hours.

Table 8. Comparison of census-tract-level reliability metrics for each year from 2020 through 2025 averaged for High-Percent-Minority-Percentile ("High PM") census tracts and for Low-Percent-Minority-Percentile ("Low PM") census tracts. Significance is assessed at α = 0.05.

Reliability Metric	Year	Low PM Mean	High PM Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.15E+03	7.69E+02	3.83E+02	6.02E-10	TRUE	High PM
	2021	1.26E+03	7.96E+02	4.61E+02	3.37E-14	TRUE	High PM
	2022	1.14E+03	7.51E+02	3.90E+02	4.06E-08	TRUE	High PM
	2023	1.18E+03	7.73E+02	4.11E+02	1.01E-10	TRUE	High PM
	2024	1.13E+03	6.93E+02	4.38E+02	5.28E-11	TRUE	High PM
	2025	1.16E+03	6.79E+02	4.81E+02	1.25E-14	TRUE	High PM
Total Customer Interruptions	2020	2.46E+03	1.47E+03	9.89E+02	2.17E-09	TRUE	High PM
	2021	2.99E+03	1.38E+03	1.60E+03	5.97E-27	TRUE	High PM
	2022	2.39E+03	1.26E+03	1.13E+03	2.01E-13	TRUE	High PM
	2023	2.57E+03	1.37E+03	1.21E+03	2.01E-14	TRUE	High PM
	2024	2.52E+03	1.17E+03	1.34E+03	1.76E-18	TRUE	High PM
	2025	2.61E+03	1.09E+03	1.52E+03	6.12E-24	TRUE	High PM
SAIDI including MEDs	2020	5.27E+02	3.67E+02	1.60E+02	6.94E-04	TRUE	High PM
	2021	9.98E+02	3.20E+02	6.78E+02	2.83E-42	TRUE	High PM
	2022	4.70E+02	2.41E+02	2.29E+02	4.44E-14	TRUE	High PM
	2023	9.69E+02	3.90E+02	5.79E+02	3.16E-13	TRUE	High PM
	2024	5.03E+02	2.64E+02	2.39E+02	1.69E-09	TRUE	High PM
	2025	1.01E+03	6.32E+02	3.74E+02	7.77E-05	TRUE	High PM
SAIDI excluding MEDs	2020	2.01E+02	1.42E+02	5.96E+01	1.86E-05	TRUE	High PM
	2021	2.49E+02	1.51E+02	9.75E+01	1.53E-09	TRUE	High PM
	2022	1.88E+02	1.22E+02	6.55E+01	1.74E-06	TRUE	High PM
	2023	1.84E+02	1.40E+02	4.38E+01	3.07E-03	TRUE	High PM
	2024	1.68E+02	9.82E+01	6.96E+01	1.34E-06	TRUE	High PM
	2025	1.82E+02	1.22E+02	5.93E+01	2.67E-03	TRUE	High PM
SAIFI including MEDs	2020	1.36E+00	1.02E+00	3.33E-01	1.91E-05	TRUE	High PM
	2021	1.68E+00	1.05E+00	6.22E-01	1.27E-13	TRUE	High PM
	2022	1.30E+00	9.04E-01	4.00E-01	7.26E-07	TRUE	High PM
	2023	1.42E+00	1.02E+00	3.99E-01	5.62E-06	TRUE	High PM
	2024	1.36E+00	8.15E-01	5.47E-01	7.12E-11	TRUE	High PM
	2025	1.56E+00	8.82E-01	6.80E-01	9.19E-14	TRUE	High PM

Reliability Metric	Year	Low PM Mean	High PM Mean	Difference	*p*-value	Significant?	Better?
SAIFI excluding MEDs	2020	1.03E+00	8.00E-01	2.32E-01	1.33E-03	TRUE	High PM
	2021	1.09E+00	8.56E-01	2.37E-01	8.34E-04	TRUE	High PM
	2022	9.81E-01	7.38E-01	2.43E-01	2.12E-04	TRUE	High PM
	2023	9.80E-01	8.40E-01	1.41E-01	4.74E-02	TRUE	High PM
	2024	9.24E-01	5.94E-01	3.31E-01	6.89E-07	TRUE	High PM
	2025	9.55E-01	6.00E-01	3.55E-01	5.87E-07	TRUE	High PM
CAIDI including MEDs	2020	3.59E+02	4.06E+02	-4.68E+01	2.59E-01	FALSE	N/A
	2021	5.35E+02	3.69E+02	1.66E+02	1.79E-04	TRUE	High PM
	2022	3.53E+02	2.80E+02	7.32E+01	2.59E-04	TRUE	High PM
	2023	5.50E+02	3.42E+02	2.08E+02	3.18E-07	TRUE	High PM
	2024	3.47E+02	3.42E+02	5.07E+00	8.64E-01	FALSE	N/A
	2025	5.53E+02	7.01E+02	-1.48E+02	3.97E-02	TRUE	Low PM
CAIDI excluding MEDs	2020	1.91E+02	2.01E+02	-9.75E+00	4.91E-01	FALSE	N/A
	2021	2.15E+02	1.82E+02	3.33E+01	1.34E-03	TRUE	High PM
	2022	1.90E+02	1.73E+02	1.75E+01	5.06E-02	FALSE	N/A
	2023	1.90E+02	1.81E+02	9.02E+00	3.59E-01	FALSE	N/A
	2024	1.83E+02	1.71E+02	1.20E+01	1.76E-01	FALSE	N/A
	2025	1.95E+02	2.13E+02	-1.84E+01	2.14E-01	FALSE	N/A
CEMI-4	2020	9.58E-02	4.92E-02	4.66E-02	1.41E-04	TRUE	High PM
	2021	1.40E-01	3.69E-02	1.03E-01	1.66E-24	TRUE	High PM
	2022	9.76E-02	4.21E-02	5.55E-02	1.01E-06	TRUE	High PM
	2023	1.13E-01	5.21E-02	6.08E-02	6.66E-06	TRUE	High PM
	2024	1.14E-01	4.31E-02	7.11E-02	4.57E-10	TRUE	High PM
	2025	1.46E-01	4.00E-02	1.06E-01	3.58E-13	TRUE	High PM
CEMI-5	2020	4.85E-02	2.40E-02	2.45E-02	3.35E-03	TRUE	High PM
	2021	7.86E-02	1.28E-02	6.57E-02	5.46E-27	TRUE	High PM
	2022	4.89E-02	1.77E-02	3.12E-02	1.67E-07	TRUE	High PM
	2023	5.81E-02	2.01E-02	3.80E-02	6.08E-06	TRUE	High PM
	2024	6.55E-02	1.33E-02	5.22E-02	8.40E-19	TRUE	High PM
	2025	8.27E-02	2.14E-02	6.13E-02	4.83E-09	TRUE	High PM
CEMI-7	2020	1.31E-02	3.10E-03	9.97E-03	4.42E-06	TRUE	High PM
	2021	2.17E-02	1.72E-03	2.00E-02	4.05E-16	TRUE	High PM
	2022	1.09E-02	7.75E-04	1.01E-02	6.03E-13	TRUE	High PM
	2023	1.67E-02	3.71E-03	1.30E-02	5.98E-07	TRUE	High PM
	2024	2.07E-02	8.19E-04	1.99E-02	2.17E-19	TRUE	High PM
	2025	2.70E-02	3.04E-03	2.39E-02	1.93E-11	TRUE	High PM
CEMI-10	2020	3.06E-03	2.00E-04	2.86E-03	1.53E-02	TRUE	High PM
	2021	2.33E-03	0.00E+00	2.33E-03	5.03E-07	TRUE	High PM
	2022	1.51E-03	0.00E+00	1.51E-03	4.41E-03	TRUE	High PM
	2023	2.43E-03	1.10E-05	2.42E-03	9.74E-06	TRUE	High PM
	2024	5.03E-03	1.59E-05	5.01E-03	4.02E-05	TRUE	High PM

Reliability Metric	Year	Low PM Mean	High PM Mean	Difference	*p*-value	Significant?	Better?
	2025	5.23E-03	2.35E-04	5.00E-03	4.37E-05	TRUE	High PM
CELID-5	2020	2.78E-01	2.16E-01	6.20E-02	1.36E-02	TRUE	High PM
	2021	4.14E-01	1.94E-01	2.20E-01	4.76E-20	TRUE	High PM
	2022	2.82E-01	1.98E-01	8.35E-02	4.43E-04	TRUE	High PM
	2023	3.67E-01	2.04E-01	1.63E-01	4.95E-09	TRUE	High PM
	2024	3.06E-01	1.86E-01	1.21E-01	5.87E-07	TRUE	High PM
	2025	3.89E-01	2.57E-01	1.33E-01	5.05E-06	TRUE	High PM
CELID-24	2020	8.14E-02	6.44E-02	1.71E-02	2.59E-01	FALSE	N/A
	2021	1.72E-01	3.86E-02	1.34E-01	1.36E-34	TRUE	High PM
	2022	6.34E-02	3.01E-02	3.33E-02	2.29E-05	TRUE	High PM
	2023	1.74E-01	7.37E-02	1.00E-01	2.24E-07	TRUE	High PM
	2024	7.29E-02	5.20E-02	2.08E-02	7.52E-02	FALSE	N/A
	2025	1.79E-01	1.39E-01	4.01E-02	7.79E-02	FALSE	N/A
Percentage of all-weather restorations made within 36 hours	2020	9.72E+01	9.53E+01	1.86E+00	1.13E-01	FALSE	N/A
	2021	9.44E+01	9.58E+01	-1.43E+00	2.28E-01	FALSE	N/A
	2022	9.77E+01	9.92E+01	-1.47E+00	5.10E-05	TRUE	High PM
	2023	9.28E+01	9.67E+01	-3.91E+00	3.73E-05	TRUE	High PM
	2024	9.78E+01	9.73E+01	5.03E-01	5.58E-01	FALSE	N/A
	2025	9.29E+01	8.70E+01	5.88E+00	6.94E-03	TRUE	Low PM
Percentage of catastrophic-weather restorations made within 48 hours	2020	9.03E+01	7.84E+01	1.19E+01	1.82E-03	TRUE	Low PM
	2021	7.98E+01	7.79E+01	1.92E+00	6.00E-01	FALSE	N/A
	2022	9.37E+01	9.75E+01	-3.79E+00	5.87E-02	FALSE	N/A
	2023	8.53E+01	8.92E+01	-3.92E+00	1.80E-01	FALSE	N/A
	2024	9.57E+01	9.16E+01	4.17E+00	7.42E-02	FALSE	N/A
	2025	8.52E+01	7.19E+01	1.33E+01	3.22E-04	TRUE	Low PM
Percentage of normal-weather restorations made within 8 hours	2020	9.52E+01	9.52E+01	-2.97E-02	9.80E-01	FALSE	N/A
	2021	9.33E+01	9.45E+01	-1.15E+00	2.63E-01	FALSE	N/A
	2022	9.46E+01	9.31E+01	1.49E+00	2.29E-01	FALSE	N/A
	2023	9.42E+01	9.21E+01	2.07E+00	1.39E-01	FALSE	N/A
	2024	9.44E+01	9.36E+01	7.80E-01	5.97E-01	FALSE	N/A
	2025	9.41E+01	9.35E+01	6.34E-01	5.92E-01	FALSE	N/A
Percentage of gray-sky-weather restorations made within 24 hours	2020	9.32E+01	9.42E+01	-1.02E+00	5.51E-01	FALSE	N/A
	2021	8.99E+01	8.64E+01	3.50E+00	1.56E-01	FALSE	N/A
	2022	8.97E+01	8.67E+01	2.99E+00	2.60E-01	FALSE	N/A
	2023	9.73E+01	9.52E+01	2.11E+00	2.63E-01	FALSE	N/A
	2024	9.43E+01	9.54E+01	-1.07E+00	5.59E-01	FALSE	N/A
	2025	9.50E+01	9.20E+01	2.94E+00	2.16E-01	FALSE	N/A

Summary of Comparisons of Average Reliability Among Groups of Census Tracts

Comparisons of average reliability in each year from 2020 through 2025 among EJ and Non-EJ; Urban and Rural; Low-Income and High-Income; and High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile census tracts show that when statistically significant differences in the average reliability of each pair of groups exist, it is generally the EJ, Urban, Low-Income, and High-Percent-Minority-Percentile census tracts that have better average reliability than their counterparts. The metrics by which EJ, Urban, Low-Income, and High-Percent-Minority-Percentile census tracts experienced better average reliability include SAIDI and SAIFI (both including and excluding MEDs), indicating that customers in these census tracts had shorter and less frequent interruptions on average than customers in Non-EJ, Rural, High-Income, and Low-Percent-Minority-Percentile census tracts, respectively.

EJ, Urban, Low-Income, and High-Percent-Minority-Percentile census tracts also experienced better average reliability in terms of CEMI-4, -5, -7, and -10 and CELID-5 than Non-EJ, Rural, High-Income, and Low-Percent-Minority Percentile census tracts, respectively. This indicates that smaller proportions of customers in EJ, Urban, Low-Income, and High-Percent-Minority-Percentile tracts experienced multiple sustained interruptions and long interruption durations than in Non-EJ, Rural, High-Income, and Low-Percent-Minority Percentile tracts, respectively.

Notable changes were observed in 2025 compared to the 2020 through 2024 period. For the first time, statistically significant differences were observed in the average percentage of normal-weather restorations made within 8 hours between Urban and Rural census tracts, with Urban tracts experiencing better average reliability in 2025. High-Income census tracts experienced better average reliability in 2025 than Low-Income census tracts in terms of CAIDI including MEDs and the percentage of all-weather restorations made within 36 hours. Low-Percent-Minority-Percentile census tracts also experienced better average reliability in 2025 than High-Percent-Minority-Percentile census tracts in terms of CAIDI including MEDs and the percentage of all-weather restorations made within 36 hours. Additionally, in 2025, statistically significant differences in the average percentage of catastrophic-weather restorations made within 48 hours were observed for all four pairs of census tract groups:

- Non-EJ tracts and Rural tracts experienced better average reliability in terms of the percentage of catastrophic-weather restorations made within 48 hours in 2025 than EJ tracts and Urban tracts, respectively, marking a reversal from the previous consistent pattern where EJ and Urban tracts experienced better reliability across all metrics;
- High-Income tracts experienced better average reliability than Low-Income tracts in terms of the percentage of catastrophic-weather restorations made within 48 hours in 2025, continuing a pattern previously observed in 2020 and 2024;[40] and

[40] *Ibid*, p25-27.

- Low-Percent-Minority-Percentile tracts experienced better average reliability than High-Percent-Minority-Percentile tracts in terms of the percentage of catastrophic-weather restorations made within 48 hours in 2020 and 2025.

Reliability Regression Results: Census Tracts

To assess the relationships between the demographic characteristics of different census tracts and the electric reliability experienced by customers within those census tracts, we fit mixed-effects linear regression models considering both county-level and year fixed effects to each of the 18 reliability metrics tabulated for 2010 Census tracts from 2020 through 2025. The procedure is identical to that performed in the 2025 Analysis,[41] but with an additional year of data for 2025. As before, two sets of models are implemented: (1) using MiEJScreen Overall Score as an independent variable; and (2) using Percent Minority Percentile as an independent variable.

Census-Tract-Level Reliability Regression Results Considering MiEJScreen Overall Score

For each of the 18 reliability metrics, we fit five different models with the following independent variables, for a total of 90 regression models:

1. MiEJScreen Overall Score;
2. MiEJScreen Overall Score and Poverty;
3. MiEJScreen Overall Score and Median Household Income past 12 months (in $10,000 increments)
4. MiEJScreen Overall Score and Population Density (in increments of 100 people per square mile); and
5. MiEJScreen Overall Score, Poverty, Median Household Income past 12 months, Population Density, Percent Unemployed, and Housing Burden.

Table 9 shows the values of the regression coefficients for each independent variable in each of the five models for SAIDI excluding MEDs. The MiEJScreen Overall Score has a statistically significant negative correlation with SAIDI excluding MEDs in each of the five models fitted. That is, as the MiEJScreen Overall Score of a census tract increases, its reliability as measured by SAIDI excluding MEDs tends to improve when all other variables are held constant. In Model 1, in which the MiEJScreen Overall Score is the only independent variable, a one percentage point increase in the MiEJScreen Overall Score is associated with a 1.49 minute decrease in SAIDI excluding MEDs when county and year factors are held constant. In Model 5 – which includes controls for Poverty, Median Household Income, Past 12 Months, Population Density, Percent Unemployed, and Housing Burden – an increase of one percentage point in the MiEJScreen Overall Score is associated with a 1.40 minute decrease in SAIDI excluding MEDs when all other independent variables, as well as county and year factors, are held constant.

[41] *Ibid*, p31.

The coefficients of the other predictors in Model 5 that are statistically significant can be interpreted as follows when all other independent variables, county, and year factors are held constant:

- An increase in Population Density of 100 people per square mile is associated with a 0.79 minute decrease in SAIDI excluding MEDs; and
- A one percentage point increase in Percent Unemployed is associated with an approximately 3 minute increase in SAIDI excluding MEDs.

For SAIDI excluding MEDs, the updated results for Model 5 (based on reliability data from 2020 through 2025) are generally consistent with those of the 2025 Analysis (based on reliability data from 2020 through 2024):[42]

- The MiEJScreen Overall Score coefficient in Model 5 remained relatively stable at -1.40 minutes, compared to -1.36 minutes in the prior report.[43]
- The coefficient of Population Density also remained relatively stable at -0.79 minutes, compared to a previous value of -0.9 minutes.[44]
- The coefficient of Percent Unemployed increased slightly, from 2.91 minutes in the previous analysis results to 3.03 minutes currently.[45]

As shown in Table 10, MiEJScreen Overall Score has a statistically significant negative correlation with SAIFI excluding MEDs in each of the five models fitted. When all else is held constant, increasing MiEJScreen Overall Score is associated with decreasing SAIFI excluding MEDs, indicating improving reliability at the census-tract level. These results are consistent with those of the 2025 Analysis.[46]

As shown in Appendix A, MiEJScreen Overall Score has a statistically significant ($p < 0.05$) negative correlation with the following reliability metrics in Model 5: SAIDI including MEDs; SAIFI including MEDs; CAIDI excluding and including MEDs; CELID-5 and -24; CEMI-4, -5, and -7; Total Customer Interruptions; and Unique Customers with an Interruption. When all else is held constant, as the MiEJScreen Overall Score of a census tract increases, its reliability (as measured by the aforementioned metrics) tends to improve. The correlation between MiEJScreen Overall Score and the remaining reliability metrics (namely, CEMI-10 as well as the restoration percentages) is not statistically significant at the $p < 0.05$ level. This is largely consistent with the results of the 2025 Analysis.[47] Considered as a whole, these results show no evidence that census

[42] *Ibid*, p33.

[43] *Ibid*, p33.

[44] *Ibid*.

[45] *Ibid*.

[46] *Ibid*, p33-34.

[47] *Ibid*, p35-36.

tracts with higher MiEJScreen Overall Scores tend to have worse reliability than other census tracts.

Table 9. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIDI excluding MEDs (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIDI excluding MEDs	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-1.49e+00*** (1.20e-01)	-1.60e+00*** (1.59e-01)	-1.62e+00*** (1.81e-01)	-1.12e+00*** (1.48e-01)	-1.40e+00*** (1.99e-01)
Poverty	-	1.36e-01 (1.29e-01)	-	-	2.66e-01 (1.83e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	-1.84e+00 (1.97e+00)	-	1.05e+00 (2.35e+00)
Population Density (People per Sq. Mile)	-	-	-	-7.51e-01*** (1.81e-01)	-7.88e-01*** (1.87e-01)
Percent Unemployed	-	-	-	-	3.03e+00*** (5.97e-01)
Housing Burden	-	-	-	-	-2.57e-01 (1.53e-01)

Table 10. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIFI excluding MEDs (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIFI excluding MEDs	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-6.12e-03*** (4.60e-04)	-6.79e-03*** (6.11e-04)	-6.77e-03*** (6.97e-04)	-4.43e-03*** (5.70e-04)	-5.83e-03*** (7.68e-04)
Poverty	-	8.13e-04 (4.95e-04)	-	-	1.02e-03 (7.02e-04)
Median Household Income, Past 12 Months (per $10,000)	-	-	-9.40e-03 (7.60e-03)	-	4.44e-03 (9.02e-03)
Population Density (People per Sq. Mile)	-	-	-	-3.49e-03*** (6.94e-04)	-3.89e-03*** (7.18e-04)
Percent Unemployed	-	-	-	-	1.03e-02*** (2.29e-03)

Housing Burden	-	-	-	-	-2.02e-04 (5.88e-04)

Census-Tract-Level Reliability Regression Results Considering Percent Minority Percentile

For each of the 18 reliability metrics, we fit five different models with the following independent variables, for a total of 90 regression models:

1. Percent Minority Percentile;
2. Percent Minority Percentile and Poverty;
3. Percent Minority Percentile and Median Household Income past 12 months (in $10,000 increments)
4. Percent Minority Percentile and Population Density (in increments of 100 people per square mile); and
5. Percent Minority Percentile, Poverty, Median Household Income past 12 months, Population Density, Percent Unemployed, and Housing Burden.

Table 11 shows that Percent Minority Percentile has a statistically significant negative correlation with SAIDI excluding MEDs in each of the five models that were fitted. As the Percent Minority Percentile of a census tract increases, the reliability of that census tract (as measured by SAIDI excluding MEDs) also tends to increase, when all other independent variables, as well as county and year factors, are held constant. In Model 5, a one percentage point increase in the Percent Minority Percentile of a census tract is associated with a decrease of approximately 1 minute in the census tract's SAIDI excluding MEDs when all other variables are held constant. This is consistent with previously reported findings based on reliability data from 2020 through 2024.[48] The coefficients of the other independent variables in Model 5 can be interpreted as follows when all other independent variables, as well as county and year factors, are held constant:

- A one percentage point increase in Poverty is associated with a 0.6 minute increase in SAIDI excluding MEDs;
- A $10,000 increase in Median Household Income, Past 12 Months is associated with a 9 minute increase[49] in SAIDI excluding MEDs;
- An increase in Population Density of 100 people per square mile is associated with a decrease of 0.9 minutes in SAIDI excluding MEDs;

[48] *Ibid*, p35.

[49] In the 2025 Analysis, we stated erroneously on p35 that a $10,000 increase in Median Household Income, Past 12 Months is associated with a 0.9 minute increase in SAIDI excluding MEDs. Per Table 11 on p36 of the 2025 Analysis, that increase is in fact associated with a 9 minute increase in SAIDI excluding MEDs. The result of our current analysis is therefore consistent with the result of the 2025 Analysis.

- A one percentage point increase in Percent Unemployed is associated with a 3.2 minute increase in SAIDI excluding MEDs; and
- The correlation between Housing Burden and SAIDI excluding MEDs is not statistically significant at the $p < 0.05$ level.

With the exception of Housing Burden, which did have a statistically significant correlation with SAIDI excluding MEDs in the previous model, the present magnitude, direction, and statistical significance of the correlations between the independent variables in Model 5 and SAIDI excluding MEDs are consistent with those of the previous model that was fitted using reliability data from 2020 through 2024.[50]

A statistically significant negative correlation is also observed between Percent Minority Percentile and SAIFI excluding MEDs, as shown in Table 12. When all else is held constant, increasing Percent Minority Percentile is associated with improving reliability at the census tract level. These results are consistent with those of the 2025 Analysis.[51]

As shown in Appendix A, Percent Minority Percentile has a statistically significant ($p < 0.05$) negative correlation with the following reliability metrics: SAIDI including MEDs; SAIFI including MEDs; CELID-5 and -24; CEMI-4, -5, -7, and -10; Total Customer Interruptions; and Unique Customers with an Interruption. When all else is held constant, as the Percent Minority Percentile of a census tract increases, its reliability (as measured by the aforementioned metrics) tends to improve. The correlation between Percent Minority Percentile and the remaining reliability metrics (namely, CAIDI excluding and including MEDs as well as the restoration percentages) is not statistically significant at the $p < 0.05$ level. This is largely consistent with the results of the previous model fitted using reliability data from 2020 through 2024.[52]

Considered as a whole, these results show no evidence that census tracts with higher Percent Minority Percentile values tend to have worse reliability than other census tracts.

Table 11. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIDI excluding MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIDI excluding MEDs	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-1.16e+00*** (1.03e-01)	-1.15e+00*** (1.35e-01)	-9.54e-01*** (1.21e-01)	-8.09e-01*** (1.21e-01)	-9.85e-01*** (1.42e-01)

[50] Consumers Energy Company. Rate Case No. U-21870. "Reliability Regression Analysis for Environmental Justice Communities". Exhibit A-135. June 2, 2025. p35.

[51] *Ibid*, pA-18.

[52] *Ibid*, p35-36.

Poverty	-	-2.57e-02 (1.27e-01)	-	-	5.76e-01** (1.89e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	5.07e+00*** (1.53e+00)	-	8.78e+00*** (2.09e+00)
Population Density	-	-	-	-9.70e-01*** (1.70e-01)	-9.11e-01*** (1.82e-01)
Percent Unemployed	-	-	-	-	3.18e+00*** (5.99e-01)
Housing Burden	-	-	-	-	-2.60e-01 (1.53e-01)

Table 12. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIFI excluding MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIFI excluding MEDs	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-4.77e-03*** (3.98e-04)	-4.84e-03*** (5.19e-04)	-3.94e-03*** (4.67e-04)	-3.17e-03*** (4.63e-04)	-4.09e-03*** (5.45e-04)
Poverty	-	1.11e-04 (4.87e-04)	-	-	2.30e-03** (7.27e-04)
Median Household Income, Past 12 Months (per $10,000)	-	-	2.00e-02*** (5.90e-03)	-	3.66e-02*** (8.05e-03)
Population Density	-	-	-	-4.37e-03*** (6.55e-04)	-4.40e-03*** (6.99e-04)
Percent Unemployed	-	-	-	-	1.09e-02*** (2.30e-03)
Housing Burden	-	-	-	-	-2.16e-04 (5.88e-04)

Reliability Regression Results: Feeders

The feeder-level regression analysis in the 2025 Analysis[53] was repeated with updated feeder characteristics[54] and annual reliability data for 2020 through 2025. Feeder reliability was measured in terms of SAIDI and SAIFI, each excluding and including MEDs. For each feeder reliability metric, we fit six different mixed-effects linear regression models to feeder and demographic characteristics in order to determine: (1) how much of the variation in reliability can be attributed to differences between feeders; and (2) to which feeder characteristics or demographic characteristics of the communities served by a feeder the variation in reliability could be correlated. A total of twenty-four mixed-effects linear regression models (six models for each of four feeder reliability metrics) were therefore fitted.

Each of the six mixed-effects linear regression models included different independent variables and fixed effects. Two categories of independent variables were considered: (1) feeder characteristics; and (2) demographic characteristics of the census tracts served by a feeder. The feeder characteristics included in some of the six mixed-effects linear regression models were:

- Customers per Primary Line Mile;
- Mean Canopy Cover Percentage;
- Open Wire Secondary Miles;
- Primary Miles;
- Primary Underground Percentage;
- Voltage,[55] as a categorical variable with the most common (4.8/8.32 kV Wye Grounded) as the reference value; and
- Years Since Last Trim < 7, which was a binary variable with a value of 1 if the vegetation near the feeder had been trimmed in the past seven years and 0 otherwise.

Table 13 lists the different voltage levels and configurations represented in Consumers' electric distribution system, as well as the percentage of feeders that fall into each voltage category. Because it accounts for approximately 55% of feeders, the 4.8/8.3 kV Wye Grounded voltage category is defined as the reference voltage, i.e., the category to which other voltage categories are compared.

[53] *Ibid*, p38.

[54] Time-varying feeder characteristic data were not available for the 2025 Analysis or the present analysis. Both the 2025 Analysis and current analysis assume that feeder characteristics do not vary with time. However, the feeder characteristic data used in the present analysis differ from the data used in the 2025 Analysis. Some changes reflect work undertaken by Consumers, such as circuit fractionalization. It is important to consider that the circuit characteristics used in the current analysis may be different than those used previously for the same circuits, so comparison of overall trends between the two analyses are more meaningful than direct comparisons of regression coefficient values.

[55] Voltage categories in the updated data exclude some categories that existed in the data from the 2025 Analysis and have been replaced with a new "MULTIPLE" category.

Demographic characteristics were included as binary variables in some of the six regression models. A feeder was considered to serve a particular type of census tract – as defined by a particular demographic characteristic – if any part of its length overlapped with any census tract of that type, as previously discussed. The demographic characteristics included in some of the regression models are listed below; all take a value of 1 if the feeder serves the type of census tract described and take a value of 0 otherwise:

- Serves an EJ census tract;
- Serves an Urban census tract;
- Serves a Low-Income census tract; and
- Serves a High-Percent-Minority-Percentile census tract.

The six types of mixed-effects linear regression models that we fit are:

1. Intercept-only: This model provides an overall mean reliability across all feeders across all years when not controlling for any other variables;
2. Feeder characteristic fixed effects: This model quantifies the correlation between each feeder characteristic and feeder reliability;
3. Year fixed effects: This model quantifies potential time-dependent effects on feeder reliability;
4. Feeder characteristic and year fixed effects: This model quantifies the correlation of each feeder characteristic with feeder reliability, considering any potential time-based fixed effects;
5. Demographic fixed effects: This model includes only demographic characteristics and quantifies their correlation with feeder reliability; and
6. Combined effects: This model includes both feeder and demographic characteristics and accounts for any potential time-based fixed effects.

Table 13. The percentage of feeders in Consumer's electric distribution system at each voltage level and configuration.

Voltage	Percentage of Feeders
4.8/8.32 kV Wye Grounded	55.5
7.2/12.47 kV Wye Grounded	22.7
MULTIPLE	18.4
14.4/24.9 kV Wye Grounded	2.5
7.2 kV Delta	0.8
4.8 kV Delta	0.1

Between-Feeder and Within-Feeder Variability

Figure 1 shows the Intraclass Coefficient (“ICC”) for each regression model and demonstrates how explained variance changes with the introduction of different predictors. The ICC is

calculated as previously described[56] and is the ratio of the amount of variance in the model that is explained by between-group variance to the total amount of variance in the model (i.e., the sum of between-group and within-group variance). The ICC can range from 0 to 1, with values closer to 0 indicating greater within-feeder variability and values closer to 1 indicating greater between-feeder variability.

The intercept-only model suggests there is a certain level of baseline variability that is attributed to within-feeder variance and not differences between feeders. The ICC values for the intercept-only models of SAIDI excluding MEDs, SAIDI including MEDs, SAIFI excluding MEDs, and SAIFI including MEDs are 0.59, 0.22, 0.43, and 0.49, respectively. These ICC values indicate that 41%, 78%, 57%, and 51%, respectively, of the variability in these reliability metrics stems from within-feeder variance rather than from differences between feeders. The remaining variability, indicated by the ICC value, results from differences between feeders that additional predictors may help explain.

For all four reliability metrics, Model 2, which includes only feeder characteristic effects, has a lower ICC than Model 5, which includes only demographic characteristic effects. Model 2 having a lower ICC than Model 5 indicates that feeder characteristics explain more of the between-feeder variability than demographic characteristics. For example, for SAIDI excluding MEDs, the ICC decreasing from 0.59 with Model 1 (the intercept-only model) to 0.50 with Model 2 (in which only feeder characteristics are included) means that the feeder characteristics included in Model 2 explain some of the between-feeder variance that is unexplained in Model 1. Model 5 (in which only demographic characteristics are included) has an ICC of 0.58, indicating that the addition of demographic characteristics explains little of the between-feeder variability that is unexplained in Model 1. Similarly, the ICC of Model 6 (which includes both feeder and demographic characteristics) is the same or very similar to that of Model 2 (which includes only feeder characteristics). This further supports the notion that the demographic characteristics included in some of the models do not explain differences in between-feeder reliability but that the feeder characteristics do explain some of these differences.

Also notable is the difference in reliability (as reflected by Model 1, the intercept-only model) for each metric depending on whether MEDs are considered. For SAIDI, approximately 59% of the variability can be attributed to between-feeder differences in the intercept-only model when MEDs are excluded. When MEDs are included, the variability due to between-feeder differences decreases to 22%. For SAIFI, approximately 43% of the variability can be attributed to between-feeder differences in Model 1 when MEDs are excluded. When MEDs are included, the variability due to between-feeder differences increases to 49%. This indicates that when MEDs are included in the reliability metric, SAIFI is more sensitive to differences between feeders than SAIDI.

[56] Consumers Energy Company. Rate Case No. U-21870. "Reliability Regression Analysis for Environmental Justice Communities". Exhibit A-135. June 2, 2025. p17.

For all four reliability metrics, the inclusion of the year fixed effect (Model 3) did not help explain additional between-feeder variability based on the ICC value relative to the intercept-only model (Model 1), as the ICC value of Model 3 is the same as (or, for SAIDI including MEDs, slightly larger than) that of Model 1. Similarly, there was no change in ICC when comparing feeder characteristics-only (Model 2) and feeder characteristics and year fixed effects (Model 4). These observations indicate that there is not a time-based effect that helps explain differences in reliability between feeders.

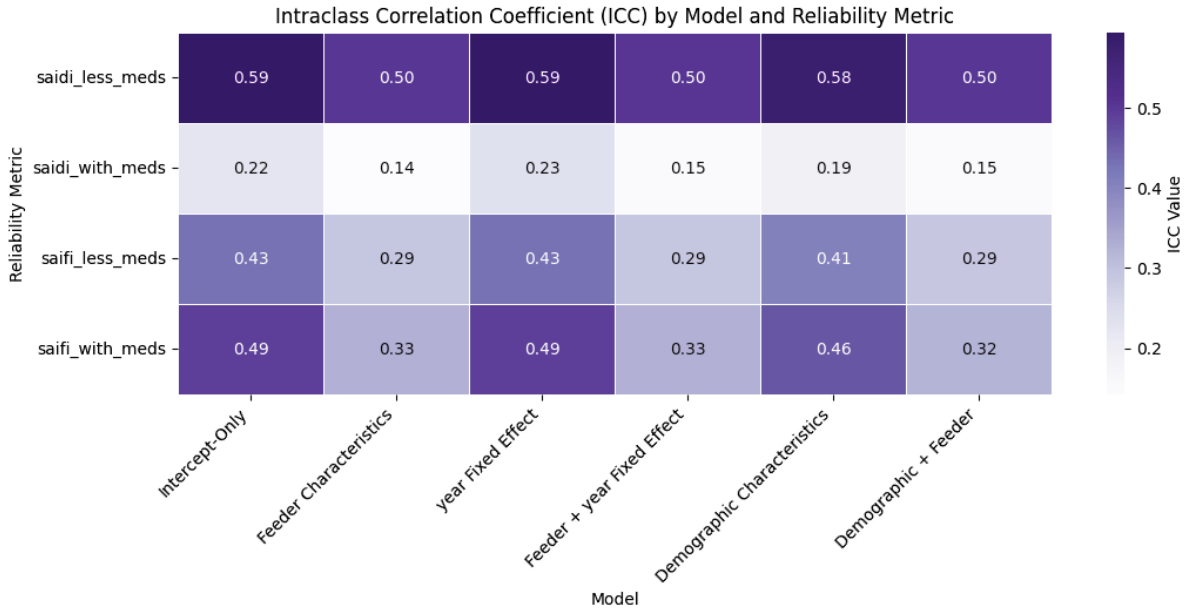


Figure 1. Heatmap of Intraclass Correlation Coefficient ("ICC") values for each reliability metric and feeder-level reliability regression model.

Feeder-Level Reliability Regression Results

The procedure from the 2025 Analysis[57] is repeated for each feeder reliability metric. The coefficients, standard errors, and p-values for each independent variable in each of the six models are estimated and shown in Table 13 (for SAIDI excluding MEDs) through Table 16 (for SAIFI including MEDs). Figure 2 through Figure 5 plot the coefficients from Model 6, which includes feeder characteristics, demographic characteristics, and year fixed effects. Because the Serves Urban, Serves Low Income, Serves High Percent Minority Percentile, Serves EJ, and Years Since Last Trim < 7 predictors are binary variables, their coefficients are the difference in mean reliability between the two groups they represent after controlling for other variables. The coefficients associated with the different voltage categories represent the difference in mean

[57] *Ibid*, p38.

reliability between the voltage of interest and the reference voltage after controlling for other variables.

SAIDI excluding MEDs

For SAIDI excluding MEDs, the regression coefficients of the independent variables in Model 6 are plotted in Figure 2. Table 13 reports the coefficients, standard errors, and p-values for all models for SAIDI excluding MEDs. For Model 6, the coefficients of the feeder characteristics that are statistically significant can be interpreted as follows when all other variables and factors are held constant:

- Voltage: 14.4/24.9 kV Wye Grounded: Feeders in this voltage category have a 274.9-minute longer mean SAIDI excluding MEDs than feeders at the reference voltage (4.8/8.32 kV Wye Grounded). This indicates that, on average, 14.4/24.9 kV Wye Grounded feeders have longer outage durations than 4.8/8.32 kV Wye Grounded feeders when all other variables and factors are held constant.
- Voltage: 7.2/12.47 kV Wye Grounded: Feeders in this voltage category have a 30.8-minute longer mean SAIDI excluding MEDs than feeders at the reference voltage.
- Voltage: MULTIPLE: Feeders in this voltage category have a 31.0-minute longer mean SAIDI excluding MEDs than feeders at the reference voltage.
- Primary Underground Percentage: A one percentage-point increase in Primary Underground Percentage is associated with a 0.86 minute decrease in SAIDI excluding MEDs.
- Customers per Primary Line Mile: An increase of 1 customer per primary line mile is associated with a 0.53 minute decrease in SAIDI excluding MEDs.
- Mean Canopy Cover Percentage: A one percentage-point increase in Mean Canopy Cover Percentage is associated with a 3.9 minute increase in SAIDI excluding MEDs.
- Primary Miles: Every one-mile increase in Primary Miles is associated with a 1.7 minute increase in SAIDI excluding MEDs.

None of the demographic characteristics has a statistically significant correlation with SAIDI excluding MEDs.

The signs of the coefficients in this model broadly agree with our physical understanding of the distribution system. For example, 14.4/24.9 kV Wye Grounded feeders (Figure B3) and 7.2/12.47 kV Wye Grounded feeders (Figure B2) tend to serve census tracts in more remote parts of Consumers' service territory than feeders at the reference voltage (Figure B1). When outages occur, it may therefore take longer for crews to access those feeders, resulting in longer outage durations. When all other variables and factors are held constant, increasing feeder length (in terms of Primary Miles) is also associated with longer outage durations, which may reflect the

difficulty of precisely locating faults on longer circuits and repairing them. Similarly, increasing Mean Canopy Cover Percentage is associated with longer outage durations, which may reflect that locations with greater vegetation are also more remote and require more time to reach when outages occur. In contrast, increasing customer density is associated with shorter outage durations when all other variables and factors are held constant, which may reflect that faults on lines that serve more customers are easier to locate, to access, and may also be of higher priority to remedy. Increasing undergrounding is also associated with shorter outage durations, which is somewhat unexpected, though consistent with the results of the 2025 Analysis.

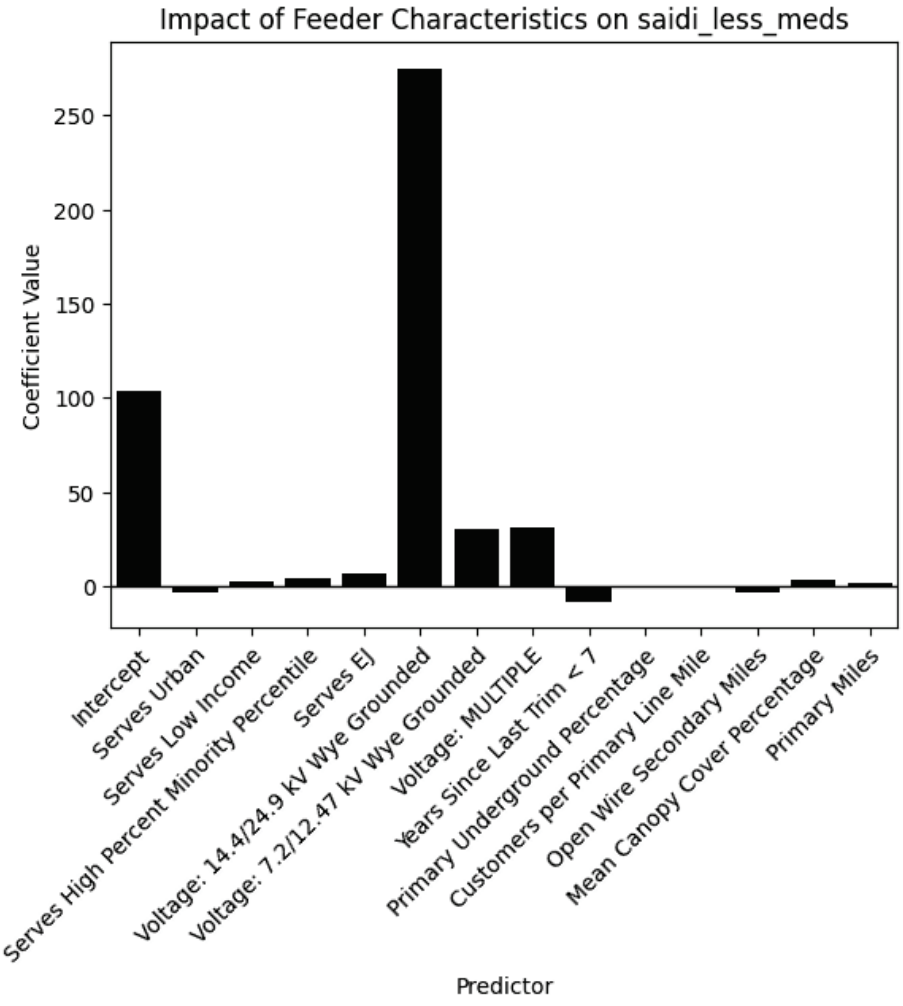


Figure 2. Regression coefficients for Model 6 (including feeder characteristics, demographic characteristics, and year fixed effects) of SAIDI excluding MEDs.

Table 14. Mixed-effects linear regression models for SAIDI excluding MEDs. Coefficients are given with standard errors in parentheses. * indicates significance at the p < 0.05 level.

Model:	1	2	3	4	5	6
Intercept	190.150* (6.097)	101.227* (18.069)	190.590* (8.135)	104.019* (19.062)	199.830* (6.376)	103.760* (19.102)
Serves Urban					-25.005* (5.949)	-3.362 (6.118)
Serves Low Income					-1.983 (7.873)	2.406 (7.897)
Serves High Percent Minority Percentile					-1.879 (14.679)	4.250 (14.696)
Serves EJ					-3.508 (10.400)	6.499 (10.455)
Voltage: 14.4/24.9 kV Wye Grounded		273.868* (37.012)		275.293* (37.087)		274.882* (37.064)
Voltage: 7.2/12.47 kV Wye Grounded		30.373* (13.555)		30.976* (13.585)		30.801* (13.592)
Voltage: MULTIPLE		30.479* (15.320)		31.219* (15.358)		31.006* (15.340)
Years Since Last Trim < 7		-4.959 (7.080)		-8.011 (7.485)		-7.978 (7.485)
yearnp.int64(2021			14.108 (7.471)	13.925 (7.558)		13.929 (7.561)
yearnp.int64(2022			-14.276* (7.249)	-15.415* (7.362)		-15.407* (7.365)
yearnp.int64(2023			4.597 (7.105)	2.565 (7.280)		2.574 (7.283)
yearnp.int64(2024			-5.490 (7.045)	-8.081 (7.294)		-8.071 (7.296)
yearnp.int64(2025			1.252 (6.996)	-1.255 (7.300)		-1.238 (7.303)
Primary Underground Percentage		-0.886* (0.303)		-0.893* (0.304)		-0.859* (0.307)
Customers per Primary Line Mile		-0.538* (0.159)		-0.531* (0.159)		-0.529* (0.161)
Open Wire Secondary Miles		-2.984 (2.604)		-2.951 (2.610)		-2.955 (2.619)
Mean Canopy Cover Percentage		3.822* (0.508)		3.868* (0.511)		3.873* (0.511)
Primary Miles		1.691* (0.258)		1.696* (0.259)		1.696* (0.260)

SAIDI including MEDs

For SAIDI including MEDs, the regression coefficients of the independent variables in Model 6 are plotted in Figure 3. The coefficients, standard errors, and p-values for all models are tabulated in Table 14. For Model 6, the coefficients of the feeder characteristics that are statistically significant can be interpreted as follows when all other variables and factors are held constant:

- Voltage: 14.4/24.9 kV Wye Grounded: Feeders in this voltage category have a 290-minute longer mean SAIDI including MEDs than feeders at the reference voltage (4.8/8.32 kV Wye Grounded).

- Voltage: 7.2/12.47 kV Wye Grounded: Feeders in this voltage category have a 117-minute shorter mean SAIDI including MEDs than feeders at the reference voltage.
- Primary Underground Percentage: A one percentage-point increase in Primary Underground Percentage is associated with a 6.0 minute decrease in SAIDI including MEDs.
- Customers per Primary Line Mile: An increase of 1 customer per primary line mile is associated with a 2.2 minute decrease in SAIDI including MEDs.
- Open Wire Secondary Miles: A one-mile increase in Open Wire Secondary Miles is associated with a 24.2 minute decrease in SAIDI including MEDs.
- Mean Canopy Cover Percentage: A one percentage-point increase in mean canopy cover is associated with a 12.6 minute increase in SAIDI including MEDs.
- Primary Miles: Every one-mile increase in Primary Miles is associated with a 5.8 minute increase in SAIDI including MEDs.

None of the demographic characteristics included in the model has a statistically significant correlation with SAIDI including MEDs.

Though the signs of the coefficients in this model broadly agree with our physical understanding of the distribution system, it is somewhat surprising that 7.2/12.47 kV Wye Grounded feeders (which primarily serve areas in the northern and western parts of Consumers' service territory, as shown in Figure B2) have shorter average outage durations when MEDs are included than feeders at the reference voltage (when all other variables and factors are held constant). This observation is consistent with our 2025 Analysis[58] and may reflect preparations made in advance of forecasted Major Event Days that reduce outage durations in more remote parts of Consumers' service territory.

[58] *Ibid*, p47.

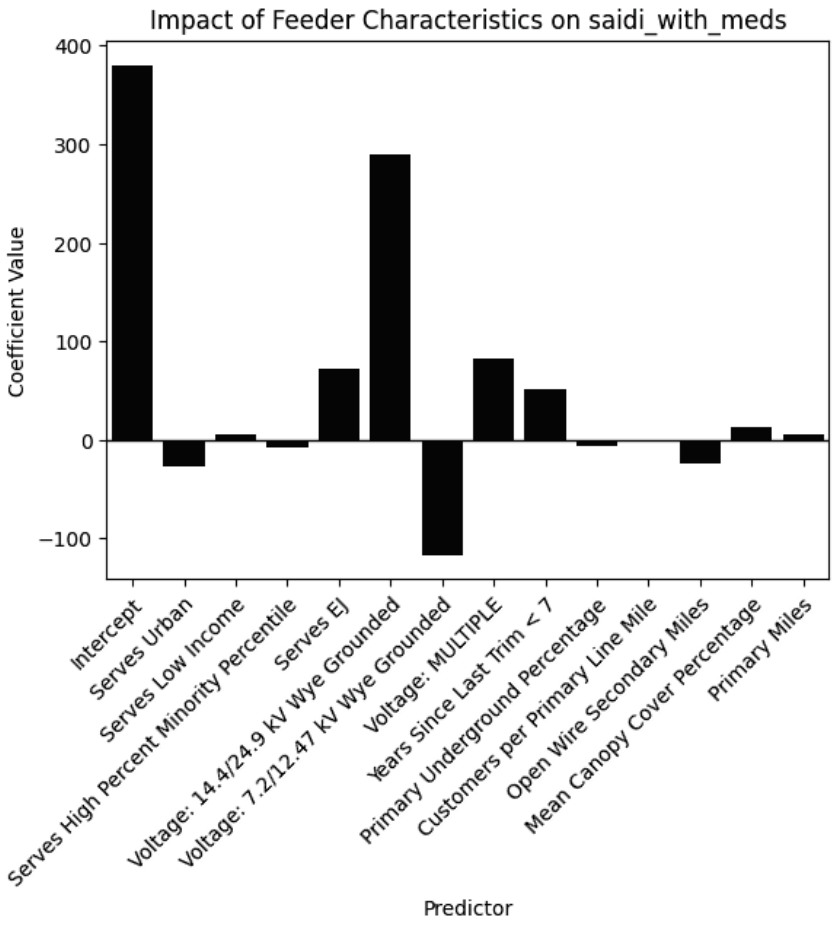


Figure 3. Regression coefficients for Model 6 (including feeder characteristics, demographic characteristics, and year fixed effects) of SAIDI including MEDs.

Table 15. Mixed-effects linear regression models for SAIDI including MEDs. Coefficients are given with standard errors in parentheses. * indicates significance at the $p < 0.05$ level.

Model:	1	2	3	4	5	6
Intercept	762.103* (19.501)	627.152* (58.463)	518.521* (36.465)	379.927* (66.054)	872.024* (21.857)	380.279* (66.589)
Serves Urban					-277.118* (30.583)	-26.922 (32.529)
Serves Low Income					-0.212 (43.318)	5.598 (42.145)
Serves High Percent Minority Percentile					-42.837 (81.013)	-7.869 (78.248)
Serves EJ					-34.086 (56.643)	72.392 (55.526)
Voltage: 14.4/24.9 kV Wye Grounded		306.268* (118.042)		293.414* (118.007)		289.888* (118.106)

Model:	1	2	3	4	5	6
Voltage: 7.2/12.47 kV Wye Grounded		-104.215* (42.542)		-113.219* (42.619)		-116.679* (42.836)
Voltage: MULTIPLE		99.656* (49.604)		84.707 (49.620)		82.352 (49.596)
Years Since Last Trim < 7		12.653 (32.450)		51.255 (32.496)		52.032 (32.495)
yearnp.int64(2021			293.756* (43.646)	294.067* (43.781)		294.204* (43.793)
yearnp.int64(2022			-40.062 (42.233)	-39.341 (42.356)		-39.121 (42.368)
yearnp.int64(2023			522.733* (41.271)	524.351* (41.443)		524.599* (41.453)
yearnp.int64(2024			61.891 (40.816)	64.285 (41.068)		64.564 (41.078)
yearnp.int64(2025			432.859* (40.205)	433.883* (40.441)		434.159* (40.451)
Primary Underground Percentage		-6.496* (0.953)		-6.304* (0.955)		-6.023* (0.981)
Customers per Primary Line Mile		-2.144* (0.489)		-2.214* (0.490)		-2.218* (0.504)
Open Wire Secondary Miles		-23.266* (8.014)		-24.825* (8.036)		-24.220* (8.140)
Mean Canopy Cover Percentage		13.430* (1.651)		12.553* (1.654)		12.577* (1.661)
Primary Miles		5.741* (0.843)		5.809* (0.842)		5.775* (0.853)

SAIFI excluding MEDs

For SAIFI excluding MEDs, the regression coefficients of the independent variables in Model 6 are plotted in Figure 4. The coefficients, standard errors, and p-values for all models are tabulated in Table 15. For Model 6, the coefficients of the feeder characteristics that are statistically significant can be interpreted as follows:

- Voltage: 14.4/24.9 kV Wye Grounded: Feeders in this voltage category have 0.8 more interruptions per customer, on average, than feeders at the reference voltage.
- Voltage: 7.2/12.47 kV Wye Grounded: Feeders in this voltage category have 0.2 more interruptions per customer, on average, than feeders at the reference voltage.
- Voltage: MULTIPLE: Feeders in this voltage category have 0.2 more interruptions per customer, on average, than feeders at the reference voltage.
- Primary Underground Percentage: A one percentage-point increase in Primary Underground Percentage is associated with a decrease of 0.004 interruptions per customer.
- Customers per Primary Line Mile: An increase of 1 customer per primary line mile is associated with a decrease of 0.002 interruptions per customer.
- Mean Canopy Cover Percentage: A one percentage-point increase in mean canopy cover is associated with an increase of 0.02 interruptions per customer.
- Primary Miles: Every one-mile increase in Primary Miles is associated with an increase of 0.009 interruptions per customer.

None of the demographic characteristics has a statistically significant correlation with SAIFI excluding MEDs.

The signs of the coefficients in this model broadly agree with our physical understanding of the distribution system and are generally consistent with the results of the 2025 Analysis. When all other variables and factors are held constant, increasing Primary Underground Percentage is associated with fewer interruptions. This is consistent with our understanding that undergrounding reduces outages caused by vegetation contact and other environmental factors to which overhead wires are susceptible. Increases in Mean Canopy Cover Percentage and Primary Miles are associated with increased interruption frequency. Higher vegetation density increases chances of vegetation contact and longer lines have more exposure to potential hazards, increasing the likelihood of interruptions.

Feeders with 14.4/24.9 kV Wye Grounded and 7.2/12.47 kV Wye Grounded voltages are higher voltage than the reference of 4.8/8.32 kV Wye Grounded. It is unsurprising that circuits with higher electrical demand experience more frequent interruptions, and this is consistent with our 2025 findings. Similarly, increasing customer density is associated with less frequent interruptions. This characteristic was not significant in the 2025 Analysis and is a somewhat surprising result. This may be explained in part by feeder age, which was not included as a variable in the model.

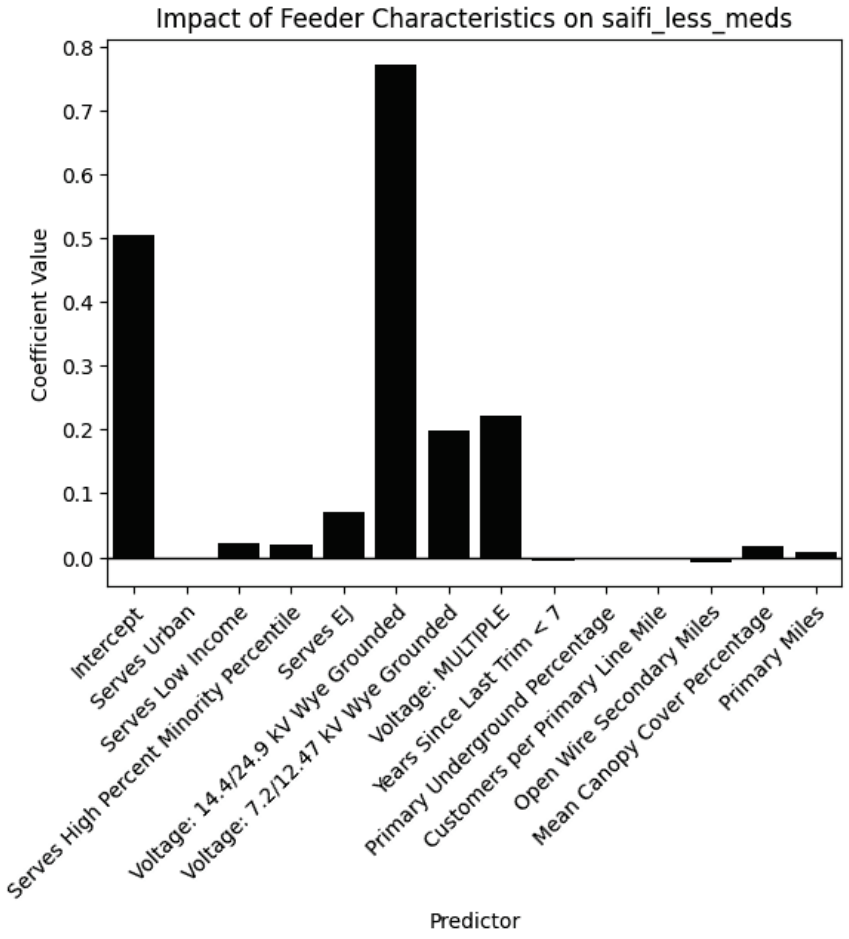


Figure 4. Regression coefficients for Model 6 (including feeder characteristics, demographic characteristics, and year fixed effects) of SAIFI excluding MEDs.

Table 16. Mixed-effects linear regression models for SAIFI excluding MEDs. Coefficients are given with standard errors in parentheses. * indicates significance at the p < 0.05 level.

Model:	**1**	**2**	**3**	**4**	**5**	**6**
Intercept	0.985* (0.021)	0.491* (0.058)	1.003* (0.032)	0.513* (0.063)	1.045* (0.022)	0.505* (0.063)
Serves Urban					-0.157* (0.025)	-0.004 (0.026)
Serves Low Income					-0.012 (0.034)	0.022 (0.034)
Serves High Percent Minority Percentile					-0.018 (0.064)	0.021 (0.063)
Serves EJ					-0.003 (0.045)	0.071 (0.045)
Voltage: 14.4/24.9 kV Wye Grounded		0.770* (0.117)		0.771* (0.117)		0.773* (0.117)

Model:	1	2	3	4	5	6
Voltage: 7.2/12.47 kV Wye Grounded		0.200* (0.043)		0.201* (0.043)		0.199* (0.043)
Voltage: MULTIPLE		0.223* (0.049)		0.223* (0.049)		0.222* (0.049)
Years Since Last Trim < 7		-0.007 (0.028)		-0.006 (0.029)		-0.006 (0.029)
yearnp.int64(2021			-0.003 (0.033)	-0.004 (0.034)		-0.004 (0.034)
yearnp.int64(2022			-0.085* (0.032)	-0.089* (0.033)		-0.089* (0.033)
yearnp.int64(2023			-0.007 (0.032)	-0.014 (0.032)		-0.014 (0.032)
yearnp.int64(2024			-0.013 (0.031)	-0.021 (0.032)		-0.021 (0.032)
yearnp.int64(2025			-0.006 (0.031)	-0.012 (0.032)		-0.012 (0.032)
Primary Underground Percentage		-0.004* (0.001)		-0.004* (0.001)		-0.004* (0.001)
Customers per Primary Line Mile		-0.002* (0.000)		-0.002* (0.000)		-0.002* (0.001)
Open Wire Secondary Miles		-0.006 (0.008)		-0.006 (0.008)		-0.007 (0.008)
Mean Canopy Cover Percentage		0.016* (0.002)		0.016* (0.002)		0.017* (0.002)
Primary Miles		0.009* (0.001)		0.009* (0.001)		0.009* (0.001)

SAIFI including MEDs

For SAIFI including MEDs, the regression coefficients of the independent variables in Model 6 are plotted in Figure 5. The coefficients, standard errors, and p-values for all models are tabulated in Table 16.

For Model 6, the coefficients of the feeder characteristics that are statistically significant can be interpreted as follows:

- Voltage: 14.4/24.9 kV Wye Grounded: Feeders in this voltage category have 0.9 more interruptions per customers, on average, than feeders at the reference voltage.
- Voltage: 7.2/12.47 kV Wye Grounded: Feeders in this voltage category have 0.2 more interruptions per customer, on average, than feeders at the reference voltage.
- Voltage: MULTIPLE: Feeders in this voltage category have 0.3 more interruptions per customer, on average, than feeders at the reference voltage.
- Primary Underground Percentage: A one percentage-point increase in primary underground percentage is associated with a decrease of 0.006 interruptions per customer.
- Customers per Primary Line Mile: An increase of 1 customer per primary line mile is associated with a decrease of 0.003 interruptions per customer.

- Mean Canopy Cover Percentage: A one percentage-point increase in mean canopy cover is associated with an increase of 0.03 interruptions per customer.
- Primary Miles: Every one-mile increase in primary miles is associated with an increase of 0.013 interruptions per customer.

None of the demographic characteristics included in the model has a statistically significant correlation with SAIFI including MEDs.

The signs of the coefficients in this model for SAIFI including MEDs are the same as those of the coefficients for SAIFI excluding MEDs and broadly agree with our physical understanding of the distribution system.

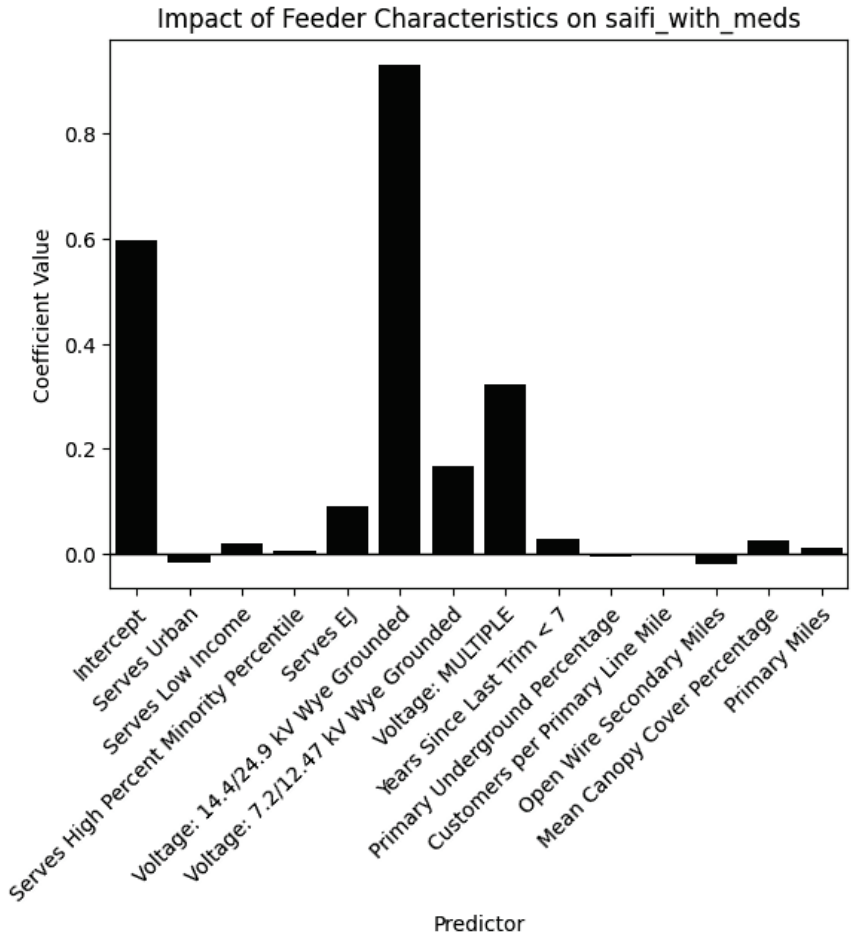


Figure 5. Regression coefficients for Model 6 (including feeder characteristics, demographic characteristics, and year fixed effects) of SAIFI including MEDs.

Table 17. Mixed-effects linear regression models for SAIFI including MEDs. Coefficients are given with standard errors in parentheses. * indicates significance at the p < 0.05 level.

Model:	1	2	3	4	5	6
Intercept	1.476* (0.030)	0.750* (0.080)	1.341* (0.043)	0.602* (0.086)	1.564* (0.031)	0.597* (0.086)
Serves Urban					-0.228* (0.034)	-0.015 (0.034)
Serves Low Income					-0.017 (0.045)	0.020 (0.045)
Serves High Percent Minority Percentile					-0.042 (0.084)	0.006 (0.083)
Serves EJ					-0.018 (0.060)	0.092 (0.059)
Voltage: 14.4/24.9 kV Wye Grounded		0.942* (0.161)		0.931* (0.161)		0.931* (0.160)
Voltage: 7.2/12.47 kV Wye Grounded		0.175* (0.059)		0.170* (0.059)		0.167* (0.059)
Voltage: MULTIPLE		0.339* (0.067)		0.325* (0.067)		0.323* (0.067)
Years Since Last Trim < 7		-0.032 (0.038)		0.030 (0.039)		0.030 (0.039)
yearnp.int64(2021			0.168* (0.043)	0.167* (0.044)		0.168* (0.044)
yearnp.int64(2022			-0.088* (0.042)	-0.090* (0.043)		-0.090* (0.043)
yearnp.int64(2023			0.140* (0.041)	0.137* (0.042)		0.138* (0.042)
yearnp.int64(2024			0.144* (0.041)	0.142* (0.042)		0.143* (0.042)
yearnp.int64(2025			0.268* (0.040)	0.269* (0.042)		0.269* (0.042)
Primary Underground Percentage		-0.006* (0.001)		-0.006* (0.001)		-0.006* (0.001)
Customers per Primary Line Mile		-0.003* (0.001)		-0.003* (0.001)		-0.003* (0.001)
Open Wire Secondary Miles		-0.016 (0.011)		-0.017 (0.011)		-0.018 (0.011)
Mean Canopy Cover Percentage		0.027* (0.002)		0.026* (0.002)		0.026* (0.002)
Primary Miles		0.013* (0.001)		0.013* (0.001)		0.013* (0.001)

Summary of Feeder-Level Reliability Regression Analysis Results

Of the physical characteristics included in the regression models, Voltage often has a statistically significant and relatively large effect on SAIDI and SAIFI, both including and excluding MEDs, indicating that feeder voltages and configurations other than the reference voltage often have quite different average reliability than the reference voltage (4.8/8.32 kV Wye Grounded, the most common circuit configuration in the distribution system).

Primary Miles and Mean Canopy Cover Percentage had statistically significant, positive correlations with SAIDI and SAIFI, both excluding and including MEDs in Model 6. These correlations indicate that as Primary Miles and Mean Canopy Cover Percentage increase, feeder

reliability tends to worsen. As the length of primary miles on a circuit increases, so does its exposure to different hazards, such as vegetation, that could cause interruptions. Similarly, as the amount of vegetation proximal to a feeder increases, so too does the likelihood of it coming into contact with a conductor and causing an outage. This also explains why Primary Underground Percentage had statistically significant, negative correlations with both SAIDI and SAIFI, both excluding and including MEDs, indicating that as the proportion of a feeder that is underground increases, reliability tends to improve. Additionally, Customers per Primary Line Mile had statistically significant, negative correlations with both SAIDI and SAIFI, both excluding and including MEDs, indicating that feeders serving more customers per mile of primary line tend to have better average reliability. Open-Wire Secondary Miles had a statistically significant, negative correlation with SAIDI including MEDs, indicating that feeders with more open-wire secondary miles tend to have shorter average outage durations when Major Event Days are included; however, this relationship was not statistically significant for the other three reliability metrics studied.

None of the demographic characteristics included in the regression models – namely, whether a feeder serves Urban, EJ, Low-Income, or High-Percent-Minority-Percentile census tracts – was found to have a statistically significant correlation with feeder reliability.

Descriptive Analysis Results: Residential Involuntary Disconnection Rates

Descriptive Analysis: Average Disconnection Rates

Table 13 shows yearly statistics (namely, mean, standard deviation, minimum, median, 95th percentile, and maximum values) for disconnection rates across all census tracts in Consumers' service territory from 2020 through 2024. The statistics for 2020 through 2023 do not match those reported in the 2025 Analysis[59] because Consumers issued revised disconnection counts for 2020 through 2024 for use in this report. The disconnection rates reported here for 2020 through 2023 are greater than those in the 2025 Analysis.

Figure 6 plots the average disconnection rate among all census tracts by year and shows that the average disconnection rate among census tracts in Consumers' service territory decreased from 2021 to 2022 before increasing each year from 2022 through 2024. Both the mean and the 95th percentile disconnection rates are 11% higher in 2024 than in 2023. Figure 7 through Figure 11 show the distribution of the disconnection rate among census tracts in Consumers' service territory in each year from 2020 through 2024. All five distributions are right-skewed, with more than half of census tracts experiencing disconnection rates below 50 disconnections per 1000 households. These results are consistent with observations in the 2025 Analysis.

Of note, the maximum disconnection rate in 2024 is 92% greater than the maximum disconnection rate in 2023. The maximum disconnection rate in 2024 occurs in Census Tract 26073000703, located in Isabella County. As shown in Figure 7, this census tract is comprised predominantly by the campus of Central Michigan University and in 2024 includes 18 households and has a Percentage Renters value of 100%; this count of households likely does not reflect the 2270 people living in the census tract because the on-campus student dormitories are not counted as households. This census tract had 15 disconnections in 2024, resulting in the disconnection rate of 833.33 disconnections per 1000 households. One possible explanation for this high disconnection rate is that it reflects in part the transience of students living in apartments off campus, at the eastern edge of the census tract. Census Tract 26073000703 also had the maximum disconnection rate among census tracts in Consumers' service territory in 2022, when it had 4 disconnections and 10 households, resulting in a disconnection rate of 400 disconnections per 1000 households.

Figure 8 maps the logarithm (base 10) of the disconnection rate in each census tract in 2024 and shows that the highest disconnection rates tend to occur in the most densely populated areas.

[59] *Ibid*, p56-61.

Table 18. Descriptive statistics (i.e., mean, standard deviation, minimum, and maximum) of disconnection rates (in units of disconnections per 1000 households) among 2020 Census tracts in Consumers' service territory from 2020 through 2024.

Year	Mean	Standard Deviation	Minimum	Median	95th Percentile	Maximum	No. of Census Tracts
2020	14.90	11.56	0.40	12.15	36.88	80.62	1133
2021	53.67	52.24	0.43	39.45	175.54	363.64	1152
2022	51.56	50.16	0.37	37.31	168.46	400.00	1151
2023	58.08	54.76	0.43	43.82	176.50	435.09	1147
2024	64.68	60.65	0.41	48.46	195.76	833.33	1150

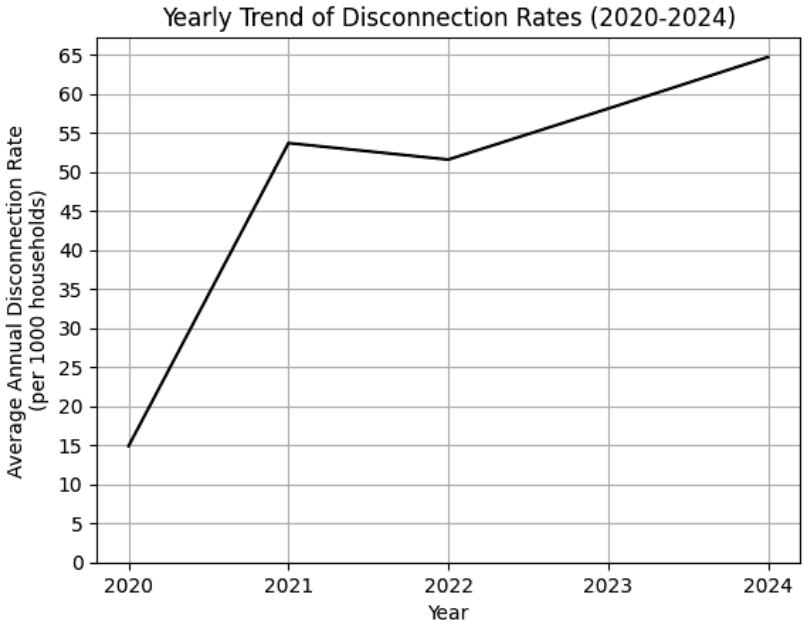


Figure 6. Average annual disconnection rate (in units of disconnections per 1000 households) for each year from 2020 through 2024 for 2020 Census tracts in Consumers' service territory.

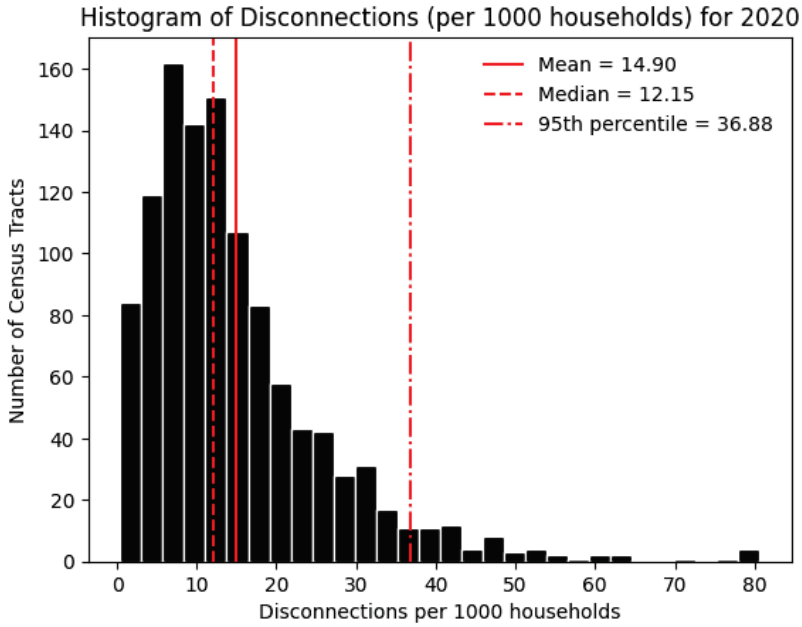


Figure 7. Histogram of 2020 Census-tract-level disconnection rates (in units of disconnections per 1000 households) for 2020.

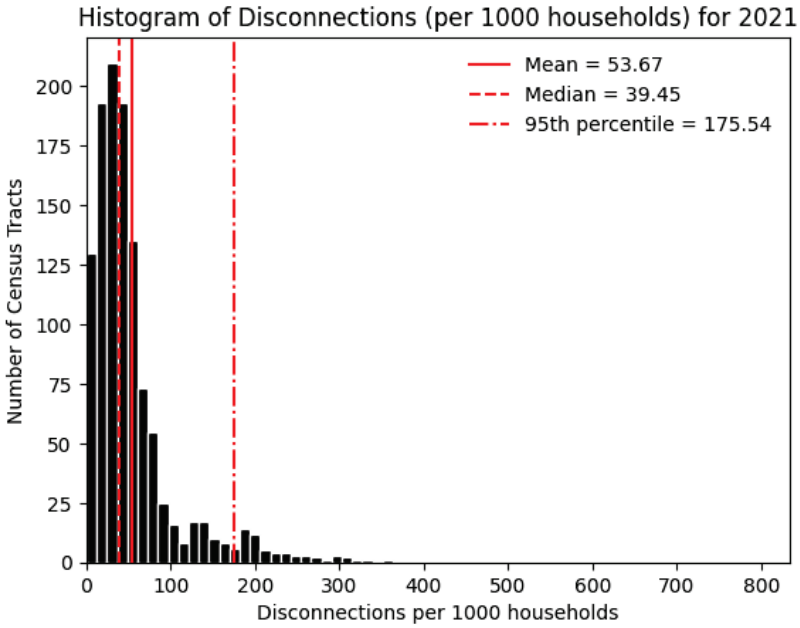


Figure 8. Histogram of 2020 Census-tract-level disconnection rates (in units of disconnections per 1000 households) for 2021.

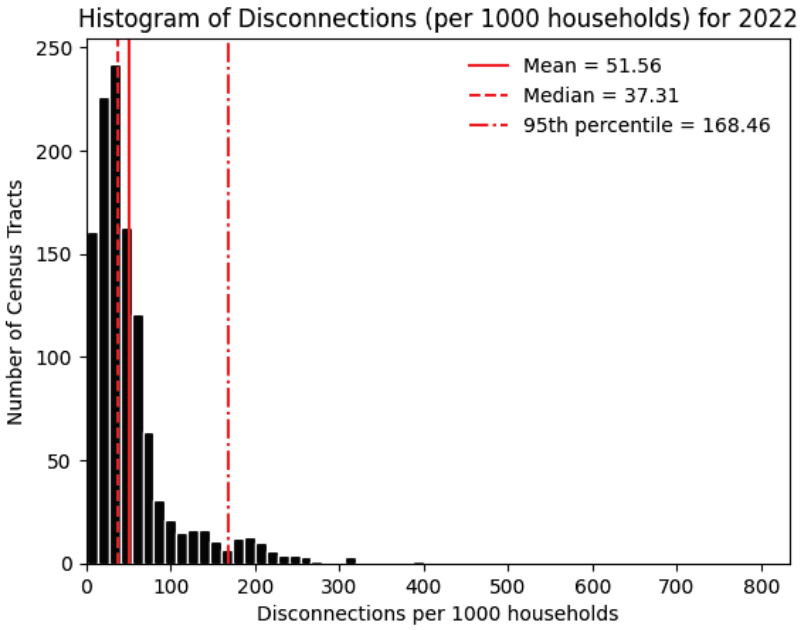


Figure 9. Histogram of 2020 Census-tract-level disconnection rates (in units of disconnections per 1000 households) for 2022.

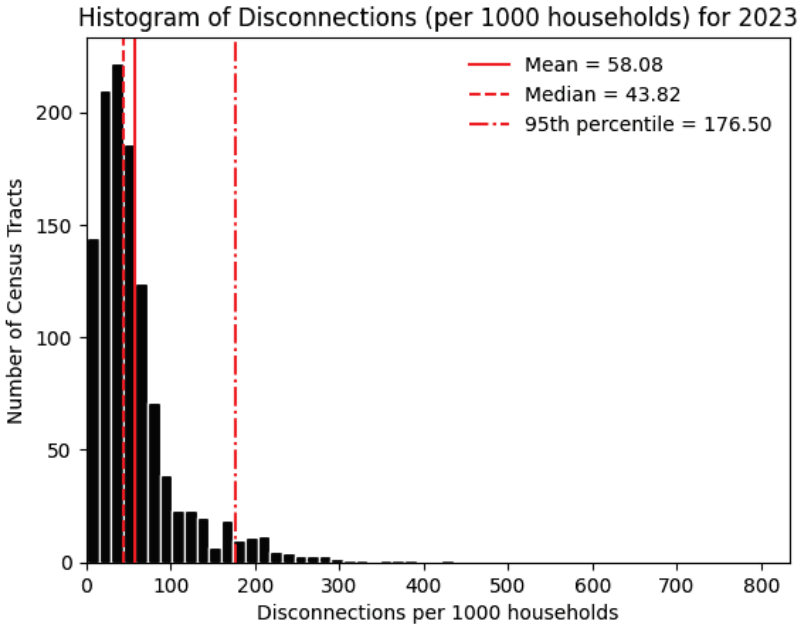


Figure 10. Histogram of 2020 Census-tract-level disconnection rates (in units of disconnections per 1000 households) for 2023.

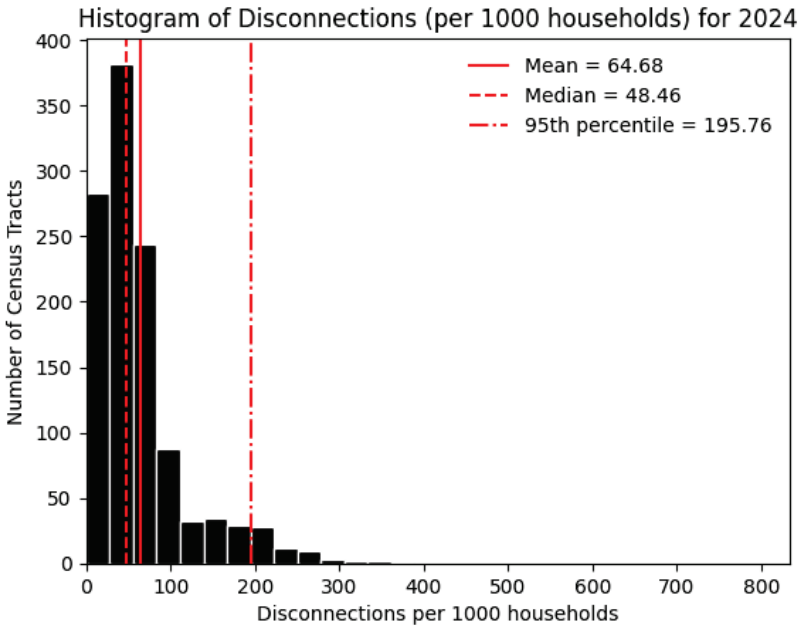


Figure 11. Histogram of 2020 Census-tract-level disconnection rates (in units of disconnections per 1000 households) for 2023.

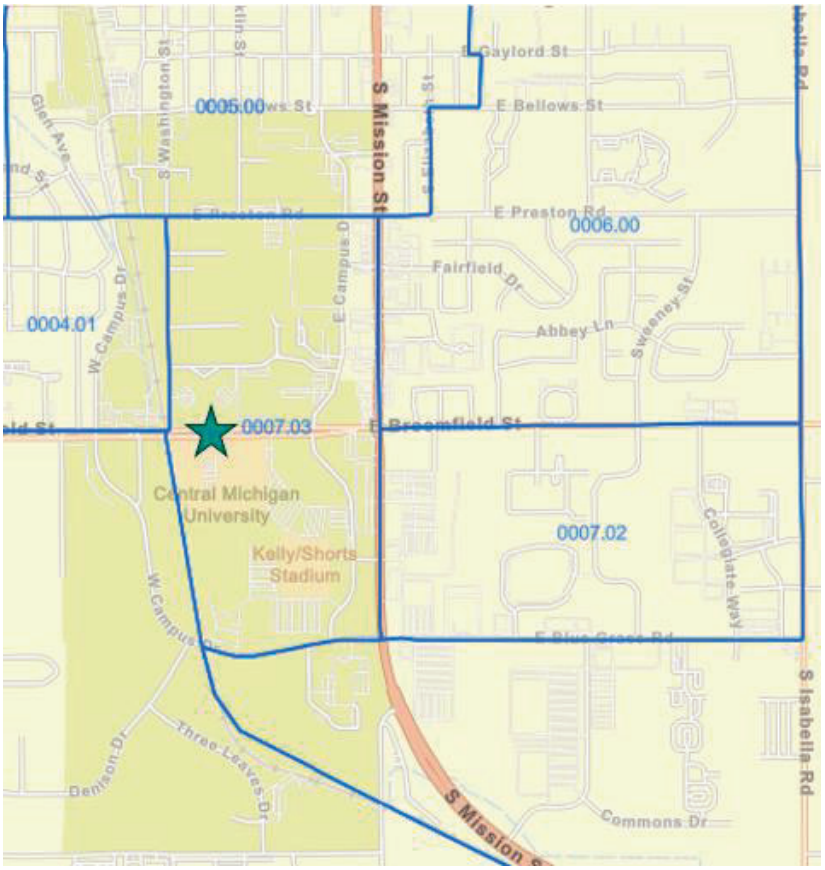


Figure 12. Map showing the boundaries of Census Tract 26073000703, labeled 0007.03, and annotated with a teal star.[60]

[60] https://geomap.ffiec.gov/ffiecgeomap/

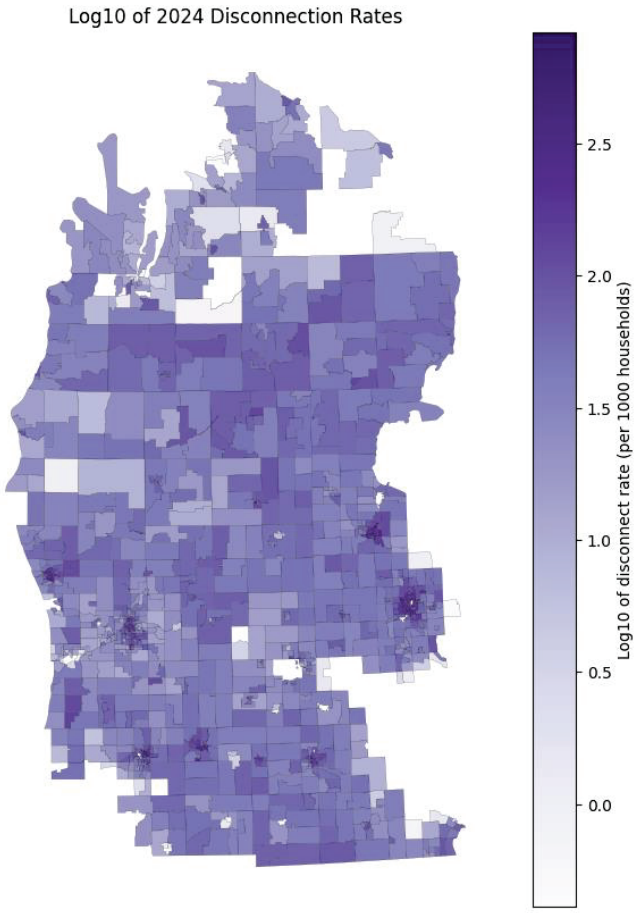


Figure 13. Map of 2020 Census tracts shaded according to the base-10 logarithm of their disconnection rate in 2024, with darker purples corresponding to higher disconnection rates.

Comparing the Average Disconnection Rates of Groups of Census Tracts

To assess whether statistically significant differences exist in the average disconnection rates of groups of census tracts in Consumers' service territory from 2020 through 2024, we carried out the binary difference-in-means *t*-test. As in the 2025 Analysis,[61] the test was performed for each of the following paired groups of census tracts in each year from 2020 through 2024:

- Low Income and High Income; and
- High Percentage Minority Population and Low Percentage Minority Population.

[61] *Ibid*, p62.

The following subsections detail the findings of each set of comparisons.

Low-Income and High-Income Census Tracts

For Low-Income and High-Income census tracts, the results of the binary difference-in-means *t*-test for each year from 2020 through 2024[62] are shown in Table 18. Consistent with the findings of the 2025 Analysis,[63] statistically significant differences in the mean disconnection rate between High-Income and Low-Income census tracts are observed in each year. Low-Income Census tracts experience higher (worse) disconnection rates on average.

Table 19. Comparison of 2020 Census-tract-level disconnection rates for each year from 2020 through 2024 averaged for Low-Income and High-Income census tracts. The difference is calculated by subtracting the Low-Income Mean from the High-Income Mean. Statistical significance is assessed at α = 0.05, and the group that experiences a worse average disconnection rate is assessed only for statistically significant differences in mean disconnection rate.

Year	High-Income Mean	Low-Income Mean	Difference	*p*-value	Significant?	Worse?
2020	13.08	31.24	-18.15	5.84E-23	TRUE	Low-Income
2021	43.23	145.42	-102.19	1.07E-26	TRUE	Low-Income
2022	41.84	135.68	-93.85	1.48E-25	TRUE	Low-Income
2023	47.35	151.01	-103.66	1.80E-24	TRUE	Low-Income
2024	53.29	164.61	-111.32	2.81E-28	TRUE	Low-Income

High-Percentage-Minority-Population and Low-Percentage-Minority-Population Census Tracts

For High-Percentage-Minority-Population and Low-Percentage-Minority-Population census tracts, the results of the binary difference-in-means *t*-test for each year from 2020 through 2024 are shown in Table 15. Consistent with the findings of the 2025 Analysis,[64] statistically significant differences in the mean disconnection rate between High-Minority and Low-Minority census tracts are observed in each year. High-Minority census tracts experience higher (worse) disconnection rates on average. The results using the updated data are generally consistent with the results reported in the 2025 Analysis.[65]

[62] Table 19 on p. 62 of the 2025 Analysis erroneously included disconnection rates for 2024 but should only have included disconnection rates for 2020 through 2023, as ACS 5-Year Estimates of the number of households in a Census tract (used with disconnect count to calculate disconnection rate) had not yet been published for 2024.

[63] Consumers Energy Company. Rate Case No. U-21870. "Reliability Regression Analysis for Environmental Justice Communities". Exhibit A-135. June 2, 2025. p62.

[64] *Ibid*.

[65] Table 20 on p. 63 of the 2025 Analysis erroneously included disconnection rates for 2024 but should only have included disconnection rates for 2020 through 2023, as ACS 5-Year Estimates of the number of households in a Census tract (used with disconnect count to calculate disconnection rate) had not yet been published for 2024.

Table 20. Comparison of 2020 Census-tract-level disconnection rates for each year from 2020 through 2024 averaged for Low-Percentage-Minority-Population and High-Percentage-Minority-Population census tracts. The difference is calculated by subtracting the High-Percentage-Minority-Population Mean from the Low-Percentage-Minority-Population. Statistical significance is assessed at $\alpha = 0.05$, and the group that experiences a worse average disconnection rate is assessed only for statistically significant differences in mean disconnection rate.

Year	Low-Minority Mean	High-Minority Mean	Difference	*p*-value	Significant?	Worse?
2020	12.81	33.89	-21.09	8.65E-26	TRUE	High-Minority
2021	42.71	152.72	-110.02	5.37E-29	TRUE	High-Minority
2022	41.25	144.26	-103.01	6.60E-31	TRUE	High-Minority
2023	46.80	161.91	-115.11	7.73E-33	TRUE	High-Minority
2024	52.77	176.34	-123.57	1.24E-37	TRUE	High-Minority

Regression Analysis Results: Residential Involuntary Disconnection Rates

We used panel linear regression models to assess correlations between rates of residential disconnections in Consumers' service territory from 2021 through 2024 to demographic characteristics from the ACS, using the annual ACS 5-Year estimates over the same time frame and data from the LEAD Tool, as described above. Consistent with the 2025 Analysis, disconnection data for 2020 were excluded given the COVID-19-related moratorium on disconnections in place for most of that year.[66] We used the following independent variables in the disconnection regression models:

- Median Home Value (in $10,000 increments);
- Percentage Minority Population;
- Percentage Below Poverty;
- Unemployment Rate;
- Percentage Renters;
- Percentage of Homes Built after 1990;
- Population Density, in units of households per square mile (in 1000 household increments); and
- Energy Burden (% Income), Electricity.

This set of independent variables is the same as was used in the 2025 Analysis, with the addition of electric energy burden. The panel linear regression takes into consideration potential fixed effects for census tracts in a particular county and year.

Table 16 shows the coefficients for each independent variable as well as their standard errors and p-values. We observe that Unemployment Rate is not statistically significant at the $p < 0.05$ level, consistent with the results of the 2025 Analysis based on disconnection rates from 2021 through 2023.[67] The remaining variables are statistically significant at the $p < 0.05$ level and have the following correlations with disconnection rates when all other independent variables, as well as county and year factors, are held constant:

- Percentage Minority Population: A one percentage-point increase in the Percentage Minority Population of a census tract is associated with an increase of 1.14 disconnections per 1000 households. This is slightly larger than the coefficient in the 2025 Analysis (1.00).[68]

[66] Consumers Energy Company. Rate Case No. U-21870. "Reliability Regression Analysis for Environmental Justice Communities". Exhibit A-135. June 2, 2025. p76.

[67] *Ibid*.

[68] *Ibid*, p76-77.

- Percentage Below Poverty Population: A one percentage-point increase in below-poverty population is associated with an increase of 0.52 disconnections per 1000 households. This is similar to the coefficient in the 2025 Analysis (0.63).[69]
- Percentage Renters: A one percentage-point increase in the percentage of renters in a census tract is associated with an increase of 0.18 disconnections per 1000 households. This is similar to the coefficient in the 2025 Analysis (0.24).[70]
- Percentage of Homes Built after 1990: A one percentage-point increase in the percentage of homes in a census tract that were built after 1990 is associated with a decrease of 0.22 disconnections per 1000 households. This is similar to the coefficient in the 2025 Analysis (-0.21).
- Population Density: An increase of 1000 households per square mile is associated with a decrease of 5.94 disconnections per 1000 households. This is similar to but smaller in magnitude than the coefficient in the 2025 Analysis (-6.97).
- Median Home Value: A $10,000 increase in a census tract's Median Home Value is associated with a decrease of 1.16 disconnections per 1000 households. This is nearly the same as in the 2025 Analysis (-1.18).
- Energy Burden (% Income), Electricity: A one percentage-point increase in the average electric energy burden of a census tract is associated with an increase of 6.86 disconnections per 1000 households. This variable was not included in the 2025 Analysis.

The regression results from the current analysis are thus largely consistent with those reported for the 2025 Analysis. The addition of Energy Burden (% Income), Electricity increases the explanatory power of the model, as indicated by the reduction in the value of the intercept in the current model (39.55) relative to the model in the 2025 Analysis (46.94).[71] The magnitude of the coefficient of Energy Burden (% Income), Electricity is the largest of all independent variables in the model. This suggests that of the variables included, the average percentage of household income that goes toward electric energy costs in a census tract has the greatest impact on the average disconnection rate of a census tract. This result is consistent with our understanding of Consumers' disconnection policies, which are, to our knowledge, based on the amount a customer is in arrears on their electric bill, the amount of time they have been in arrears, and their responsiveness to Consumers' Customer Experience Team's attempts to engage with them.

Figure 14 shows 2020 Census tracts in Consumers' service territory shaded according to the Energy Burden (% Income), Electricity data provided by the LEAD Tool. Census tracts with the highest electric energy burden tend to be in more densely populated areas – notably, Saginaw, Flint, and Ann Arbor – though not all densely populated areas have high electric energy burden (e.g., Grand Rapids, Lansing). Figure 15 shows 2020 Census tracts in Consumers' service

[69] *Ibid*.

[70] *Ibid*.

[71] *Ibid*, p77.

territory shaded by the total dollar value of Michigan Energy Assistance Program ("MEAP") funds spent in the county of which they are part.[72] Figure 16 shows 2020 Census tracts in Consumers' service territory shaded by the average MEAP funds spent per household served in the county of which they are part. A comparison of Figure 13 with Figure 15 suggests that Census tracts with the highest disconnection rates tend to be in counties with higher total MEAP funds spent but, as shown in Figure 16, lower average MEAP funds spent per household served. These maps suggest that MEAP funds may not alleviate households' electric energy burden to the extent that they can avoid disconnections, or that the MEAP funds allocated to an area may be sufficient for some but not all households in areas with the highest disconnection rates.

Table 21. Panel regression model for disconnection rate (in units of disconnections per 1000 households) considering year- and county-level fixed effects: coefficients for each independent variable, standard errors, and p-values. * indicates p < 0.05.

Variable	Coefficient	Standard Error	p-value
Intercept	39.55*	12.48	1.54E-03
Percentage Minority Population	1.14*	0.15	3.60E-14
Percentage Below Poverty	0.52*	0.20	1.08E-02
Percentage Renters	0.18*	0.06	4.17E-03
Unemployment Rate	0.28	0.43	5.12E-01
Percentage of Homes Built after 1990	-0.22*	0.07	3.13E-03
Population Density	-5.94*	2.28	9.37E-03
Median Home Value (per $10,000)	-1.16*	0.34	7.48E-04
Energy Burden (% Income), Electricity	6.86*	3.36	4.13E-02

[72] MEAP data are tabulated for counties, not census tracts.

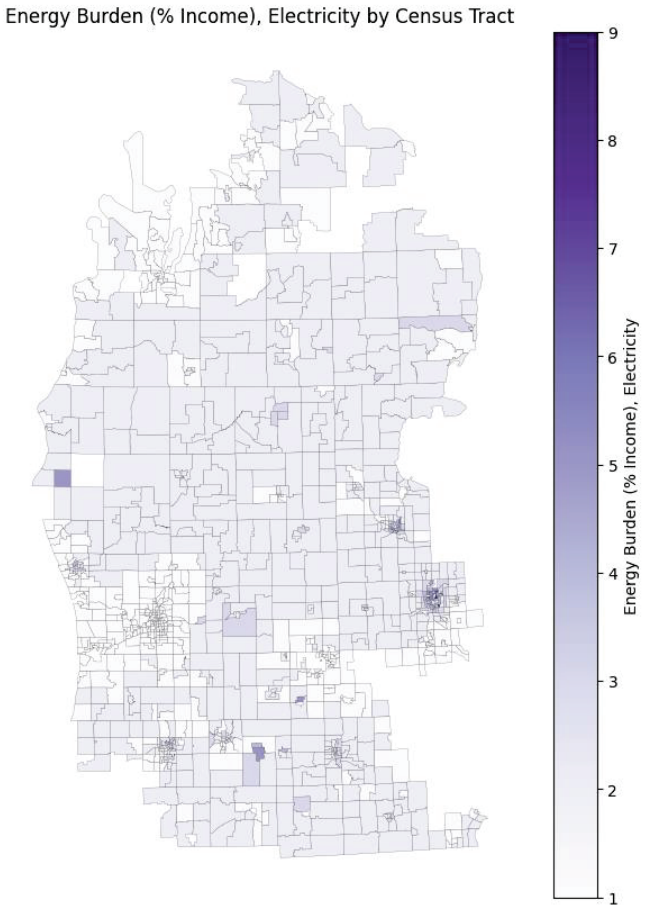


Figure 14. Map of 2020 Census tracts in Consumers' service territory shaded according to their Energy Burden (% Income), Electricity from the LEAD Tool.

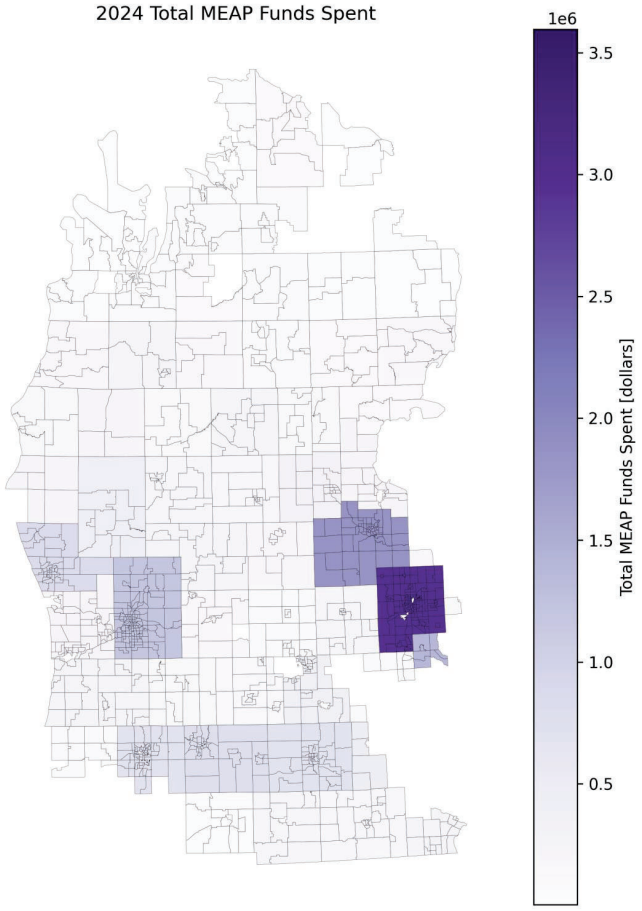


Figure 15. Map of 2020 Census tracts shaded according to the total Michigan Energy Assistance Program ("MEAP") funds spent (in dollars) at the county level.

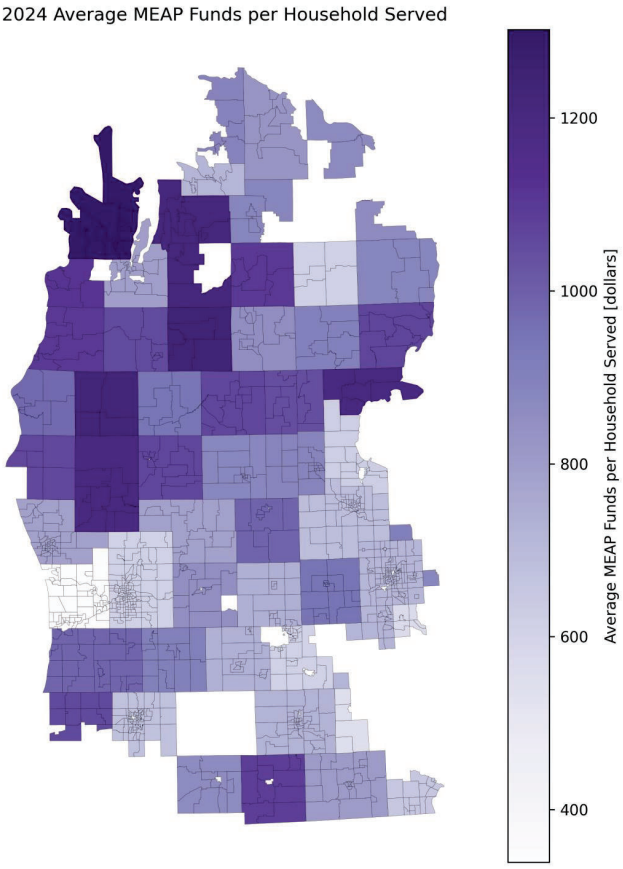


Figure 16. Map of 2020 Census tracts shaded according to the average Michigan Energy Assistance Program ("MEAP") funds spent per household served (in dollars) at the county level.

Assessing the Relationship Between Disconnection Rates and Reliability

As in the 2025 Analysis,[73] we sought to assess the relationship between demographic characteristics, disconnection rates, and reliability. The following section implements the same analysis as in the 2025 Analysis, but with updated disconnection data provided by Consumers for 2020 through 2024. Simple linear regression models are fit to each reliability metric for disconnection rates at the 2020 Census-tract-level, and a binary difference-in-means *t*-test is performed to compare the average disconnection rates of census tracts with the worst reliability to all other tracts.

[73] Consumers Energy Company. Rate Case No. U-21870. "Reliability Regression Analysis for Environmental Justice Communities". Exhibit A-135. June 2, 2025. p78.

Figure 17 through Figure 20 show scatter plots with best-fit lines from simple linear regressions for SAIDI and SAIFI (each including and excluding MEDs) data for each year from 2020 through 2024. The R^2 values for each simple linear regression model are also shown. The updated data does not change the prior observation that these measures of reliability seem to be poor predictors of disconnection rate. The largest R^2 value across all regressions remains 0.04. This is observed across all other reliability metrics regressed against disconnection rates as well, for which figures are not shown.

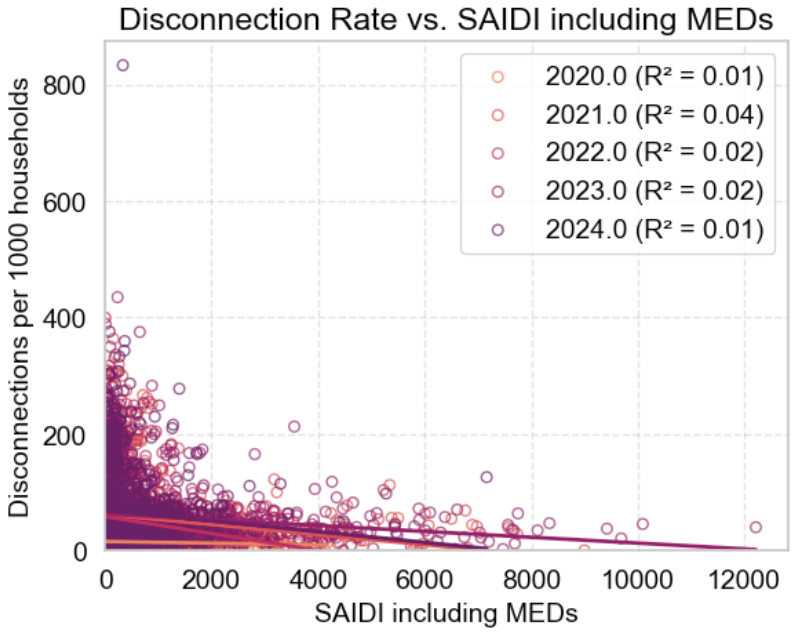


Figure 17. Disconnection rate (disconnections per 1000 households) versus SAIDI including MEDs for each year from 2020 through 2024, as well as separate best-fit lines for each year's worth of data.

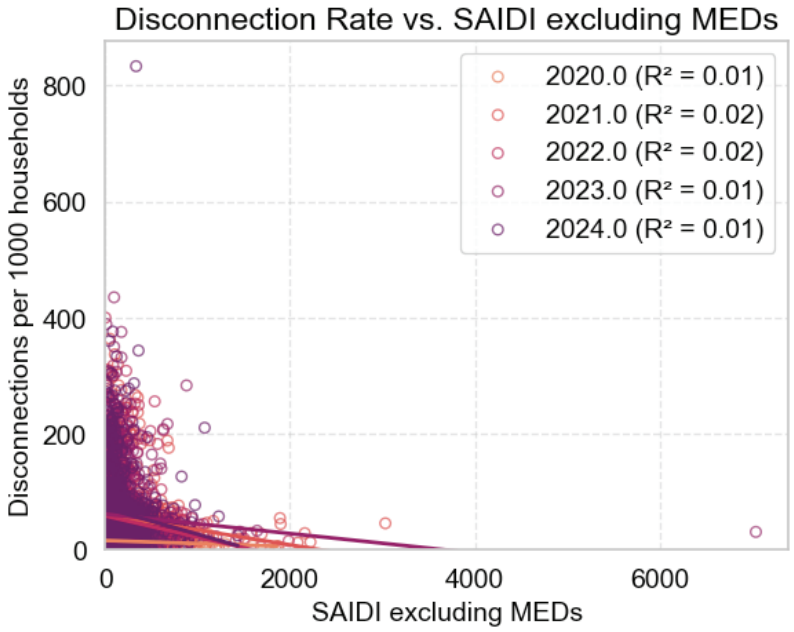


Figure 18. Disconnection rate (disconnections per 1000 households) versus SAIDI excluding MEDs for each year from 2020 through 2024, as well as separate best-fit lines for each year's worth of data.

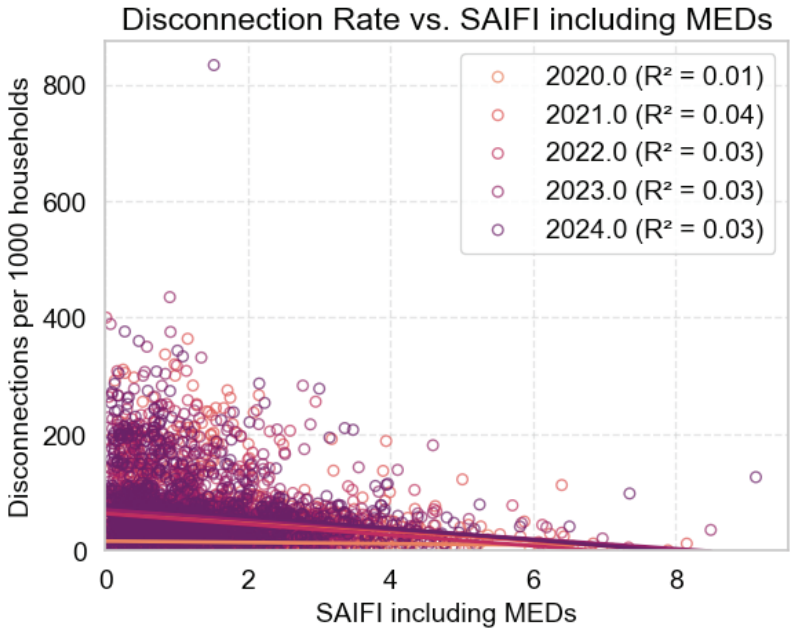


Figure 19. Disconnection rate (disconnections per 1000 households) versus SAIFI including MEDs for each year from 2020 through 2024, as well as separate best-fit lines for each year's worth of data.

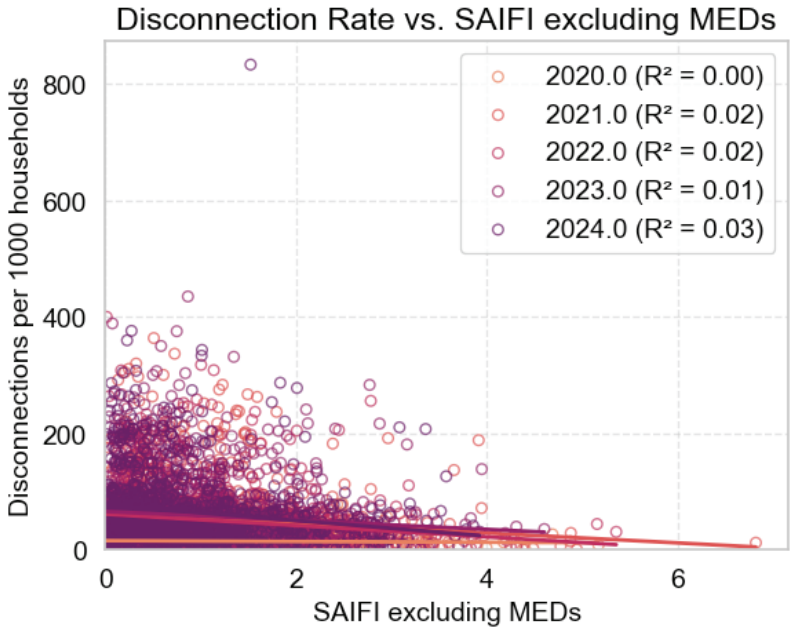


Figure 20. Disconnection rate (disconnections per 1000 households) versus SAIFI excluding MEDs for each year from 2020 through 2024, as well as separate best-fit lines for each year's worth of data.

We also compared the average disconnection rates for the census tracts with the worst reliability (according to each reliability metric) and all other census tracts to understand any potential differences in disconnections among the groups using the same method detailed in the 2025 Analysis.[74] The 10% of census tracts with the worst reliability (as measured by a particular reliability metric) were classified as Vulnerable, while all other census tracts were considered Non-Vulnerable. The average disconnection rate for each group was calculated, as well as the difference in the averages between the two groups. A binary difference-in-means *t*-test was performed to assess the statistical significance of the difference. The results are shown in Table 17. This comparison was not performed for CEMI-10 in 2020 and 2021 due to the sample size within a group being too small to determine the statistical significance of the difference.

When statistically significant differences in the average disconnection rate of census tracts with the worst reliability and all other census tracts exist, the census tracts with the worst reliability consistently have lower disconnection rates on average than all other census tracts. Census tracts classified as Vulnerable have, on average, statistically significant lower disconnection rates than their counterparts when reliability is measured with SAIDI (excluding and including MEDs), SAIFI (excluding and including MEDs); CELID-5; CEMI-4, -5, and -7; Unique Customers with an Interruption; and Total Customer Interruptions. In most years, differences in the mean disconnection rate were not statistically significant among groups of census tracts classified according to CAIDI excluding MEDs, the percentage of catastrophic-weather restorations made within 48 hours, the percentage of gray-sky-weather restorations made within 24 hours, and the percentage of normal-weather restorations made within 8 hours. This analysis therefore shows no evidence that census tracts with the worst reliability consistently experience statistically significant, higher disconnection rates than other census tracts. These results are consistent with the findings of the 2025 Analysis.

Table 22. Comparison of census-tract-level disconnection rates for each year from 2020 through 2024 averaged for the 10% of census tracts with the worst reliability per each metric (the Vulnerable group) and all other census tracts within Consumers service territory (the Non-Vulnerable group). Significance is assessed at α = 0.05.

Reliability Metric	Year	Non-Vulnerable Mean	Vulnerable Mean	Difference	p-value	Significant?	Worse?
Unique Customers with an Interruption	2020	1.52E+01	1.23E+01	2.89E+00	6.35E-05	TRUE	Non-Vulnerable
	2021	5.52E+01	4.14E+01	1.39E+01	1.45E-08	TRUE	Non-Vulnerable
	2022	5.28E+01	4.14E+01	1.14E+01	8.55E-06	TRUE	Non-Vulnerable
	2023	5.98E+01	4.53E+01	1.44E+01	1.67E-06	TRUE	Non-Vulnerable
	2024	6.64E+01	5.19E+01	1.45E+01	1.19E-05	TRUE	Non-Vulnerable
Total Customer Interruptions	2020	1.49E+01	1.48E+01	1.30E-01	8.87E-01	FALSE	N/A
	2021	5.55E+01	3.93E+01	1.62E+01	1.05E-09	TRUE	Non-Vulnerable
	2022	5.31E+01	3.88E+01	1.43E+01	3.38E-08	TRUE	Non-Vulnerable
	2023	6.02E+01	4.17E+01	1.84E+01	9.36E-10	TRUE	Non-Vulnerable

[74] *Ibid*, p81.

Reliability Metric	Year	Non-Vulnerable Mean	Vulnerable Mean	Difference	p-value	Significant?	Worse?
	2024	6.66E+01	5.10E+01	1.56E+01	1.69E-07	TRUE	Non-Vulnerable
SAIDI including MEDs	2020	1.50E+01	1.38E+01	1.20E+00	2.22E-01	FALSE	N/A
	2021	5.58E+01	3.53E+01	2.05E+01	1.23E-12	TRUE	Non-Vulnerable
	2022	5.29E+01	4.08E+01	1.21E+01	3.37E-04	TRUE	Non-Vulnerable
	2023	6.01E+01	4.23E+01	1.77E+01	2.21E-07	TRUE	Non-Vulnerable
	2024	6.61E+01	5.45E+01	1.17E+01	7.74E-03	TRUE	Non-Vulnerable
SAIDI excluding MEDs	2020	1.52E+01	1.20E+01	3.21E+00	8.49E-05	TRUE	Non-Vulnerable
	2021	5.57E+01	3.63E+01	1.93E+01	5.20E-09	TRUE	Non-Vulnerable
	2022	5.32E+01	3.77E+01	1.55E+01	5.00E-04	TRUE	Non-Vulnerable
	2023	5.98E+01	4.47E+01	1.51E+01	1.56E-03	TRUE	Non-Vulnerable
	2024	6.67E+01	4.84E+01	1.83E+01	1.25E-04	TRUE	Non-Vulnerable
SAIFI including MEDs	2020	1.51E+01	1.30E+01	2.19E+00	2.61E-02	TRUE	Non-Vulnerable
	2021	5.56E+01	3.74E+01	1.82E+01	1.20E-06	TRUE	Non-Vulnerable
	2022	5.30E+01	3.93E+01	1.37E+01	6.64E-04	TRUE	Non-Vulnerable
	2023	6.02E+01	4.12E+01	1.89E+01	1.52E-05	TRUE	Non-Vulnerable
	2024	6.66E+01	4.95E+01	1.71E+01	1.80E-04	TRUE	Non-Vulnerable
SAIFI excluding MEDs	2020	1.49E+01	1.56E+01	-7.25E-01	5.80E-01	FALSE	N/A
	2021	5.57E+01	3.60E+01	1.97E+01	1.80E-07	TRUE	Non-Vulnerable
	2022	5.30E+01	3.93E+01	1.37E+01	1.68E-03	TRUE	Non-Vulnerable
	2023	5.93E+01	4.89E+01	1.05E+01	4.42E-02	TRUE	Non-Vulnerable
	2024	6.68E+01	4.86E+01	1.82E+01	1.05E-04	TRUE	Non-Vulnerable
CAIDI including MEDs	2020	1.47E+01	1.72E+01	-2.54E+00	3.47E-02	TRUE	Vulnerable
	2021	5.54E+01	3.96E+01	1.58E+01	3.35E-06	TRUE	Non-Vulnerable
	2022	5.21E+01	4.76E+01	4.52E+00	2.19E-01	FALSE	N/A
	2023	5.99E+01	4.41E+01	1.58E+01	8.24E-06	TRUE	Non-Vulnerable
	2024	6.45E+01	6.89E+01	-4.34E+00	4.46E-01	FALSE	N/A
CAIDI excluding MEDs	2020	1.49E+01	1.49E+01	2.16E-02	9.84E-01	FALSE	N/A
	2021	5.49E+01	4.40E+01	1.08E+01	8.97E-03	TRUE	Non-Vulnerable
	2022	5.19E+01	4.97E+01	2.16E+00	6.78E-01	FALSE	N/A
	2023	5.81E+01	5.99E+01	-1.78E+00	7.64E-01	FALSE	N/A
	2024	6.47E+01	6.74E+01	-2.69E+00	7.04E-01	FALSE	N/A
CEMI-4	2020	1.51E+01	1.38E+01	1.28E+00	2.06E-01	FALSE	N/A
	2021	5.59E+01	3.48E+01	2.11E+01	3.74E-10	TRUE	Non-Vulnerable
	2022	5.33E+01	3.65E+01	1.68E+01	2.60E-06	TRUE	Non-Vulnerable
	2023	6.06E+01	3.78E+01	2.28E+01	1.11E-11	TRUE	Non-vulnerable
	2024	6.65E+01	5.11E+01	1.54E+01	3.44E-04	TRUE	Non-Vulnerable
CEMI-5	2020	1.50E+01	1.44E+01	5.99E-01	6.06E-01	FALSE	N/A
	2021	5.58E+01	3.52E+01	2.06E+01	7.49E-10	TRUE	Non-Vulnerable
	2022	5.32E+01	3.76E+01	1.57E+01	3.47E-06	TRUE	Non-Vulnerable
	2023	6.05E+01	3.87E+01	2.18E+01	1.32E-10	TRUE	Non-Vulnerable
	2024	6.68E+01	4.83E+01	1.85E+01	9.88E-06	TRUE	Non-Vulnerable

Reliability Metric	Year	Non-Vulnerable Mean	Vulnerable Mean	Difference	p-value	Significant?	Worse?
CEMI-7	2020	1.50E+01	1.39E+01	1.10E+00	3.23E-01	FALSE	N/A
	2021	5.58E+01	3.64E+01	1.93E+01	2.71E-10	TRUE	Non-Vulnerable
	2022	5.33E+01	3.67E+01	1.66E+01	9.29E-08	TRUE	Non-Vulnerable
	2023	6.03E+01	4.02E+01	2.01E+01	8.28E-09	TRUE	Non-Vulnerable
	2024	6.70E+01	4.69E+01	2.01E+01	8.73E-10	TRUE	Non-Vulnerable
CEMI-10	2022	2.42E+01	5.17E+01	-2.75E+01	3.44E-01	FALSE	N/A
	2023	1.11E+01	5.84E+01	-4.73E+01	3.81E-02	TRUE	Vulnerable
	2024	6.69E+01	4.74E+01	1.96E+01	3.73E-09	TRUE	Non-Vulnerable
CELID-5	2020	1.50E+01	1.43E+01	7.43E-01	4.51E-01	FALSE	N/A
	2021	5.56E+01	3.67E+01	1.89E+01	4.53E-08	TRUE	Non-Vulnerable
	2022	5.31E+01	3.89E+01	1.42E+01	1.32E-04	TRUE	Non-Vulnerable
	2023	6.03E+01	3.97E+01	2.06E+01	7.26E-09	TRUE	Non-Vulnerable
	2024	6.67E+01	4.88E+01	1.80E+01	1.60E-05	TRUE	Non-Vulnerable
CELID-24	2020	1.50E+01	1.44E+01	5.93E-01	5.59E-01	FALSE	N/A
	2021	5.58E+01	3.51E+01	2.07E+01	2.80E-12	TRUE	Non-Vulnerable
	2022	5.22E+01	4.64E+01	5.85E+00	1.17E-01	FALSE	N/A
	2023	6.03E+01	4.04E+01	1.98E+01	1.92E-09	TRUE	Non-Vulnerable
	2024	6.54E+01	6.15E+01	3.90E+00	4.28E-01	FALSE	N/A
Percentage of all-weather restorations made within 36 hours	2020	1.46E+01	1.75E+01	-2.90E+00	1.28E-02	TRUE	Vulnerable
	2021	5.48E+01	4.43E+01	1.05E+01	2.18E-02	TRUE	Non-Vulnerable
	2022	5.28E+01	4.10E+01	1.19E+01	4.99E-04	TRUE	Non-Vulnerable
	2023	5.88E+01	5.34E+01	5.37E+00	1.94E-01	FALSE	N/A
	2024	6.49E+01	6.56E+01	-7.11E-01	8.93E-01	FALSE	N/A
Percentage of catastrophic-weather restorations made within 48 hours	2020	1.44E+01	2.04E+01	-5.97E+00	6.63E-05	TRUE	Vulnerable
	2021	5.31E+01	6.08E+01	-7.67E+00	1.55E-01	FALSE	N/A
	2022	5.20E+01	4.69E+01	5.07E+00	2.80E-01	FALSE	N/A
	2023	5.77E+01	6.51E+01	-7.34E+00	3.21E-01	FALSE	N/A
	2024	6.42E+01	7.31E+01	-8.93E+00	1.89E-01	FALSE	N/A
Percentage of normal-weather restorations made within 8 hours	2020	1.50E+01	1.40E+01	1.01E+00	3.20E-01	FALSE	N/A
	2021	5.45E+01	4.72E+01	7.35E+00	1.17E-01	FALSE	N/A
	2022	5.13E+01	5.51E+01	-3.84E+00	4.76E-01	FALSE	N/A
	2023	5.82E+01	5.89E+01	-6.56E-01	9.11E-01	FALSE	N/A
	2024	6.45E+01	6.87E+01	-4.19E+00	5.22E-01	FALSE	N/A
Percentage of gray-sky weather restorations made within 24 hours	2020	1.50E+01	1.43E+01	7.07E-01	5.08E-01	FALSE	N/A
	2021	5.29E+01	6.24E+01	-9.53E+00	1.34E-01	FALSE	N/A
	2022	5.12E+01	5.57E+01	-4.45E+00	3.95E-01	FALSE	N/A
	2023	5.81E+01	6.04E+01	-2.35E+00	6.63E-01	FALSE	N/A
	2024	6.47E+01	6.78E+01	-3.16E+00	6.26E-01	FALSE	N/A

Discussion and Conclusions

The aim of this analysis was to assess whether evidence of disparities exists in the reliability experienced by EJ and Non-EJ communities in Consumers' service territory, as well as other potentially vulnerable communities of interest. We conducted three analyses of reliability data from 2020 through 2025:

1. Comparisons of the average reliability of EJ and Non-EJ census tracts; Urban and Rural census tracts; Low-Income and High-Income census tracts; and High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile census tracts;
2. Census tract-level reliability regression analyses with MiEJScreen Overall Score as an independent variable; and
3. Feeder-level reliability regression analyses.

As in our 2025 Analysis, which included reliability data from 2020 through 2024, the results of the first two analyses suggest that EJ communities tend to experience better reliability than Non-EJ communities, and that more vulnerable communities tend to have better reliability than less vulnerable ones.[75]

Comparisons of the average reliability in 2025 among EJ and Non-EJ; Urban and Rural; Low-Income and High-Income; and High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile Census tracts show that when statistically significant differences exist in the average reliability of each pair of groups, the EJ, Urban, Low-Income, and High-Percent-Minority-Percentile Census tracts generally have better average reliability than their counterparts. The metrics by which EJ census tracts experienced better average reliability in 2025 than Non-EJ census tracts are: Unique Customers with an Interruption; Total Customer Interruptions; SAIDI including MEDs; SAIFI including and excluding MEDs; CEMI-4, -5, -7, and -10; and CELID-5.

Exceptions to the general observation that vulnerable groups of census tracts have better average reliability than non-vulnerable groups of Census tracts in 2025 are that:

- Non-EJ census tracts have better average reliability than EJ census tracts in terms of the percentage of catastrophic-weather restorations made within 48 hours.
- Rural census tracts have better average reliability than Urban census tracts in terms of the percentage of catastrophic-weather restorations made within 48 hours.
- High-Income census tracts have better average reliability than Low-Income census tracts in terms of:
    - CAIDI including MEDs;
    - The percentage of all-weather restorations made within 36 hours; and

[75] *Ibid*, p85.

    - The percentage of catastrophic-weather restorations made within 48 hours.
- Low-Percent-Minority-Percentile Census tracts have better average reliability than High-Percent-Minority-Percentile Census tracts in terms of:
    - CAIDI including MEDs;
    - The percentage of all-weather restorations made within 36 hours; and
    - The percentage of catastrophic-weather restorations made within 48 hours.

These exceptions suggest that restoration activities in the wake of severe weather disruptions in 2025 may, on average, have restored service to census tracts that would be considered less vulnerable by the metrics considered in this analysis.

The census-tract-level reliability regression analyses indicate that increasing MiEJScreen Overall Score tends to be associated with improving reliability, when a statistically significant correlation between the two exists, and all other variables and factors are held constant. In a model that includes controls for Poverty, Median Household Income, Past 12 Months, Population Density, Percent Unemployed, and Housing Burden, this observation holds true for SAIDI excluding and including MEDs; SAIFI excluding and including MEDs; CAIDI excluding and including MEDs; CELID-5 and -24; CEMI-4, -5, and -7; Total Customer Interruptions; and Unique Customers with an Interruption. These results are consistent with the findings of the 2025 Analysis.[76]

The census-tract-level reliability regression analyses also indicate that increasing Percent Minority Percentile tends to be associated with improving reliability, when a statistically significant correlation between the two exists and all other variables and factors are held constant. In a model that includes controls for Poverty, Median Household Income, Past 12 Months, Population Density, Percent Unemployed, and Housing Burden, this observation holds true for SAIDI excluding and including MEDs; SAIFI excluding and including MEDs; CELID-5 and -24; CEMI-4, -5, -7, and -10; Total Customer Interruptions; and Unique Customers with an Interruption. These results are similar to those of the 2025 Analysis.[77]

The feeder-level reliability regression analyses indicate that physical characteristics of feeders often have statistically significant correlations with feeder reliability while demographic characteristics of the communities served by feeders do not. Primary Miles and Mean Canopy Cover Percentage have statistically significant positive correlations with reliability, indicating that increased feeder length and canopy cover are associated with increases in outage duration and frequency. Customers per Primary Line Mile has a statistically significant negative correlation with all four feeder-level reliability metrics, indicating that increasing customer density is associated with decreased outage duration and frequency. Open Wire Secondary Miles has a statistically significant correlation with only SAIDI including MEDs: an increase in Open Wire Secondary Miles is associated with reduced outage duration. Relative to the reference

[76] *Ibid*.

[77] *Ibid*, p38.

voltage (4.8/8.32 kV Wye Grounded), having an alternative voltage configuration is often statistically significant and has a large effect on reliability. For all four reliability metrics considered in the feeder-level regression analysis, no statistically significant correlations were observed with any of the demographic characteristics included in each model – namely, whether a feeder serves EJ, Urban, Low-Income, or High-Percent-Minority-Percentile census tracts.

We also used regression analysis to assess whether evidence exists of differences in the residential involuntary disconnection rates of different communities in Consumers' service territory. In addition to the independent variables previously included in the 2025 Analysis, we also included electric energy burden as a predictor in the regression model for disconnection rates. As expected, of all the variables that have a statistically significant correlation with disconnection rate, electric energy burden has the greatest correlation: a one percentage-point increase in Energy Burden (% Income), Electricity is associated with an increase of 6.86 disconnections per 1000 households when all other variables and factors are held constant. Previously the variable with the greatest statistically significant correlation with disconnection rate, Population Density now has the second largest-magnitude correlation: an increase of 1000 households per square mile is associated with a decrease of 5.94 disconnections per 1000 households when all other variables and factors are held constant.

The statistically significant correlation between Percentage Minority Population observed in the 2025 Analysis[78] persists in the current results: now, a one percentage-point increase in Percentage Minority Population is associated with an increase of 1.14 disconnections per 1000 households when all other variables and factors are held constant. It is notable that this correlation persists even when electric energy burden – as well as Median Home Value, Percentage Below Poverty, Unemployment Rate, Percentage of Homes Built after 1990, and Population Density – are controlled for. The magnitude of this correlation is greater than that of the correlations between disconnection rate and Percentage Below Poverty, Percentage Renters, Percentage of Homes Built after 1990, and nearly the same as that of Median Home Value (per $10,000). The magnitude of the correlation between Percentage Minority Population and disconnection rate is also practically significant given that the mean annual disconnection rate in Consumers' service territory in 2024 was 64.68 disconnections per 1000 households.

The correlation between minority population and disconnection rate has also been observed in recent regression analyses in the literature. In a census-block-level regression analysis of disconnection rates in Minnesota, Pradhan and Chan (2024) find that a one percentage-point increase in the minority population of a census block group is associated with an increase of 0.22 disconnections per 1000 households when all other variables and factors are held constant.[79] In a study of disconnections in California, Memmott et al. (2024) find that the percentages of a zip-code's population comprised by Black and Hispanic residents have statistically significant

[78] *Ibid*.

[79] Pradhan, B. and Chan, G. (2024). Minnesota's energy paradox: Household energy insecurity in the face of racial and economic disparities. The Electricity Journal: Vol. 37, Issue 6. p8.

positive correlations with disconnection rate, even when income, energy costs, and housing conditions (including age and number of rooms/apartments), are controlled for.[80] They report that a one percentage-point increase of the Black share of a zip code's population is associated with a 0.59% increase in disconnections per 1000 households, while a one percentage-point increase in the Hispanic share of a zip code's population is associated with a 0.26% increase in disconnections per 1000 households.[81] Interestingly, the correlation between disconnection rate and the percentage of a zip-code's population comprised of children under 5 is also statistically significant and greater than the correlations between disconnection rate and the percentages of a zip-code's population comprised by Black and Hispanic residents.[82] That is, a one percentage-point increase in the population of children under 5 in an area is associated with a greater increase in disconnection rate than one percentage-point increases in the Black or Hispanic share of the population. Cicala (2021) conducts a study using zip-code-level data on electricity disconnections in Illinois as well as socioeconomic data and detailed information on the percentage of customers levied late fees, served disconnection notices, and disconnected for non-payment as well as with past-due balances, on deferred payment plans, and in low-income assistance programs.[83] He finds that customers in Black and Hispanic zip codes were more likely to be disconnected for non-payment[84] and suggests that disconnections may be "an indicator of severe economic distress."[85] Cicala (2021) notes that his findings do not "reveal bias in utilities' treatment of poor and minority customers: individual usage, payments and balances are unobserved."[86] Instead, his results show "the disproportionate economic stress experienced in these communities."[87] The pairwise correlation coefficient between Percentage Minority Population and Energy Burden (% Income), Electricity in our data is 0.49, indicating that census tracts with greater shares of their population comprised by racial and ethnic minorities also tend to experience higher electric energy burdens.

[80] Memmott, T., Konisky, D.M., and Carley, S. (2024). *Assessing demographic vulnerability and weather impacts on utility disconnections in California*. Nature Communications, Vol. 15:9458. https://doi.org/10.1038/s41467-024-53913-y. p6.

[81] *Ibid*, p4.

[82] *Ibid*.

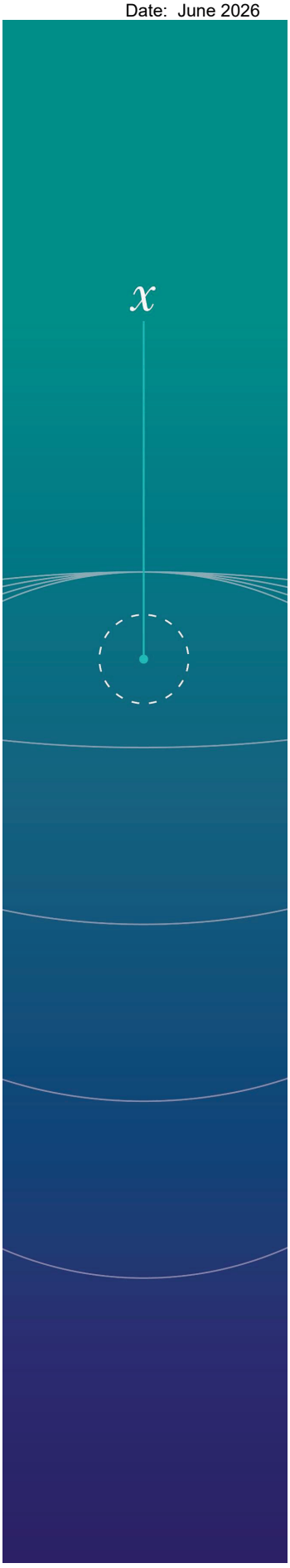
[83] Cicala, S. (2021). The incidence of extreme economic stress: evidence from utility disconnections. Journal of Public Economics, Vol. 200. p1-3.

[84] *Ibid*, p7.

[85] *Ibid*, p9.

[86] *Ibid*, p2.

[87] *Ibid*.



Appendix A

Census-Tract-Level Reliability Regression Results: Supplementary Material

A. Census-Tract-Level Reliability Regression: Supplementary Material

This appendix contains the full regression results for two sets of census-tract-level reliability regression models: (1) regression models including MiEJScreen Overall Score as an independent variable; and (2) regression models including Percent Minority Percentile as an independent variable. Each regression model was fitted for the 18 reliability metrics for which data was provided by Consumers. Each reliability metric was considered separately as a dependent variable. Therefore, a total of 180 unique regression models were fitted.

The five regression models in the first set of models are:

1. MiEJScreen Overall Score;
2. MiEJScreen Overall Score and Poverty;
3. MiEJScreen Overall Score and Median Household Income, Past 12 Months (per $10,000);
4. MiEJScreen Overall Score and Population Density (in increments of 100 people per square mile); and
5. MiEJScreen Overall Score, Poverty, Median Household Income, Past 12 Months (per $10,000), Population Density (in increments of 100 people per square mile), Percent Unemployed, and Housing Burden.

The five regression models in the second set of models are:

1. Percent Minority Percentile;
2. Percent Minority Percentile and Poverty;
3. Percent Minority Percentile and Median Household Income, Past 12 Months (per $10,000);
4. Percent Minority Percentile and Population Density (in increments of 100 people per square mile); and
5. Percent Minority Percentile, Poverty, Median Household Income, Past 12 Months (per $10,000), Population Density (in increments of 100 people per square mile), Percent Unemployed, and Housing Burden.

Because results for SAIDI excluding MEDs and SAIFI excluding MEDs are included in the main body of the report, they are not reproduced here.

Census Tract-Level Reliability Regression Results Considering MiEJScreen Overall Score

SAIDI including MEDs

Table A - 1. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIDI including MEDs (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIDI including MEDs	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-7.51e+00*** (6.29e-01)	-7.90e+00*** (8.30e-01)	-7.92e+00*** (9.41e-01)	-5.58e+00*** (7.79e-01)	-6.71e+00*** (1.04e+00)
Poverty	-	4.76e-01 (6.73e-01)	-	-	9.21e-01 (9.64e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	-6.04e+00 (1.03e+01)	-	5.87e+00 (1.23e+01)
Population Density (People per Sq. Mile)	-	-	-	-3.99e+00*** (9.54e-01)	-4.25e+00*** (9.87e-01)
Percent Unemployed	-	-	-	-	1.11e+01*** (3.15e+00)
Housing Burden	-	-	-	-	-4.95e-01 (8.07e-01)

SAIFI including MEDs

Table A - 2. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIFI including MEDs (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIFI including MEDs	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-1.09e-02*** (6.25e-04)	-1.17e-02*** (8.29e-04)	-1.17e-02*** (9.45e-04)	-8.10e-03*** (7.73e-04)	-9.94e-03*** (1.04e-03)

Poverty	-	9.03e-04 (6.72e-04)	-	-	1.61e-03 (9.54e-04)
Median Household Income, Past 12 Months (per $10,000)	-	-	-1.17e-02 (1.03e-02)	-	5.56e-03 (1.22e-02)
Population Density (People per Sq. Mile)	-	-	-	-5.84e-03*** (9.43e-04)	-6.30e-03*** (9.75e-04)
Percent Unemployed	-	-	-	-	1.46e-02*** (3.11e-03)
Housing Burden	-	-	-	-	-7.38e-04 (7.98e-04)

CAIDI excluding MEDs

Table A - 3. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CAIDI excluding MEDs (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and *denotes p < 0.05.

	Model Number				
CAIDI excluding MEDs	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-3.56e-01*** (7.18e-02)	-3.41e-01*** (9.37e-02)	-4.89e-01*** (1.06e-01)	-3.11e-01*** (8.90e-02)	-4.53e-01*** (1.17e-01)
Poverty	-	-1.92e-02 (7.63e-02)	-	-	-7.83e-02 (1.10e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	-1.99e+00 (1.16e+00)	-	-2.21e+00 (1.40e+00)
Population Density (People per Sq. Mile)	-	-	-	-9.39e-02 (1.09e-01)	-5.09e-02 (1.13e-01)
Percent Unemployed	-	-	-	-	1.49e+00*** (3.62e-01)
Housing Burden	-	-	-	-	-1.74e-01 (9.24e-02)

CAIDI including MEDs

Table A - 4. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CAIDI including MEDs (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CAIDI including MEDs	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-1.32e+00*** (2.50e-01)	-1.34e+00*** (3.27e-01)	-1.35e+00*** (3.68e-01)	-9.97e-01** (3.12e-01)	-1.17e+00** (4.11e-01)
Poverty	-	2.41e-02 (2.66e-01)	-	-	1.60e-01 (3.84e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	-4.65e-01 (4.02e+00)	-	2.49e+00 (4.88e+00)
Population Density (People per Sq. Mile)	-	-	-	-6.61e-01 (3.83e-01)	-6.31e-01 (3.96e-01)
Percent Unemployed	-	-	-	-	4.25e+00*** (1.26e+00)
Housing Burden	-	-	-	-	-3.74e-01 (3.22e-01)

CELID-5

Table A - 5. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CELID-5 (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CELID-5	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-2.85e-03*** (1.75e-04)	-2.79e-03*** (2.29e-04)	-2.73e-03*** (2.59e-04)	-2.20e-03*** (2.17e-04)	-2.26e-03*** (2.85e-04)
Poverty	-	-7.74e-05 (1.86e-04)	-	-	2.52e-04 (2.69e-04)

Median Household Income, Past 12 Months (per $10,000)	-	-	1.86e-03 (2.83e-03)	-	4.16e-03 (3.42e-03)
Population Density (People per Sq. Mile)	-	-	-	-1.35e-03*** (2.67e-04)	-1.35e-03*** (2.76e-04)
Percent Unemployed	-	-	-	-	3.08e-03*** (8.80e-04)
Housing Burden	-	-	-	-	-2.69e-04 (2.25e-04)

CELID-24

Table A - 6. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CELID-24 (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CELID-24	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-1.24e-03*** (1.26e-04)	-1.34e-03*** (1.65e-04)	-1.32e-03*** (1.86e-04)	-8.99e-04*** (1.56e-04)	-1.08e-03*** (2.07e-04)
Poverty	-	1.18e-04 (1.34e-04)	-	-	2.48e-04 (1.93e-04)
Median Household Income, Past 12 Months (per $10,000)	-	-	-1.12e-03 (2.04e-03)	-	1.07e-03 (2.46e-03)
Population Density (People per Sq. Mile)	-	-	-	-7.15e-04*** (1.92e-04)	-7.72e-04*** (1.99e-04)
Percent Unemployed	-	-	-	-	1.49e-03* (6.34e-04)
Housing Burden	-	-	-	-	-1.12e-04 (1.62e-04)

CEMI-4

Table A - 7. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-4 (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-4	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-1.57e-03*** (1.01e-04)	-1.71e-03*** (1.35e-04)	-1.83e-03*** (1.53e-04)	-1.21e-03*** (1.26e-04)	-1.60e-03*** (1.69e-04)
Poverty	-	1.76e-04 (1.09e-04)	-	-	1.58e-04 (1.55e-04)
Median Household Income, Past 12 Months (per $10,000)	-	-	-3.76e-03* (1.67e-03)	-	-1.51e-03 (1.99e-03)
Population Density (People per Sq. Mile)	-	-	-	-7.35e-04*** (1.53e-04)	-8.08e-04*** (1.59e-04)
Percent Unemployed	-	-	-	-	2.17e-03*** (5.07e-04)
Housing Burden	-	-	-	-	-7.88e-05 (1.30e-04)

CEMI-5

Table A - 8. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-5 (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-5	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-8.85e-04*** (7.42e-05)	-9.98e-04*** (9.84e-05)	-1.14e-03*** (1.12e-04)	-6.36e-04*** (9.19e-05)	-9.69e-04*** (1.23e-04)
Poverty	-	1.39e-04 (7.97e-05)	-	-	9.08e-05 (1.13e-04)

Median Household Income, Past 12 Months (per $10,000)	-	-	-3.64e-03** (1.22e-03)	-	-2.31e-03 (1.45e-03)
Population Density (People per Sq. Mile)	-	-	-	-5.13e-04*** (1.12e-04)	-5.65e-04*** (1.16e-04)
Percent Unemployed	-	-	-	-	1.46e-03*** (3.70e-04)
Housing Burden	-	-	-	-	-5.87e-05 (9.48e-05)

CEMI-7

Table A - 9. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-7 (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-7	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-2.50e-04*** (3.92e-05)	-2.79e-04*** (5.23e-05)	-3.08e-04*** (5.97e-05)	-1.82e-04*** (4.86e-05)	-2.57e-04*** (6.59e-05)
Poverty	-	3.52e-05 (4.23e-05)	-	-	6.12e-05 (6.00e-05)
Median Household Income, Past 12 Months (per $10,000)	-	-	-8.33e-04 (6.50e-04)	-	-4.74e-04 (7.72e-04)
Population Density (People per Sq. Mile)	-	-	-	-1.40e-04* (5.92e-05)	-1.45e-04* (6.13e-05)
Percent Unemployed	-	-	-	-	4.51e-04* (1.96e-04)
Housing Burden	-	-	-	-	-7.17e-05 (5.03e-05)

CEMI-10

Table A - 10. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-10 (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-10	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-3.21e-05 (1.75e-05)	-4.43e-05 (2.32e-05)	-4.01e-05 (2.65e-05)	-2.73e-05 (2.17e-05)	-3.28e-05 (2.93e-05)
Poverty	-	1.50e-05 (1.88e-05)	-	-	4.44e-05 (2.68e-05)
Median Household Income, Past 12 Months (per $10,000)	-	-	-1.17e-04 (2.89e-04)	-	-1.97e-05 (3.44e-04)
Population Density (People per Sq. Mile)	-	-	-	-9.85e-06 (2.64e-05)	-8.73e-06 (2.74e-05)
Percent Unemployed	-	-	-	-	3.75e-05 (8.75e-05)
Housing Burden	-	-	-	-	-4.52e-05* (2.24e-05)

Percentage of normal-weather restorations made within 8 hours

Table A - 11. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of normal-weather restorations made within 8 hours (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of normal-weather restorations made within 8 hours	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	3.81e-03 (7.40e-03)	-9.73e-04 (9.46e-03)	8.27e-03 (1.04e-02)	7.61e-03 (9.18e-03)	1.14e-02 (1.17e-02)
Poverty	-	6.31e-03 (7.72e-03)	-	-	1.38e-02 (1.14e-02)

Median Household Income, Past 12 Months (per $10,000)	-	-	7.01e-02 (1.15e-01)	-	1.44e-01 (1.43e-01)
Population Density (People per Sq. Mile)	-	-	-	-7.97e-03 (1.14e-02)	-1.32e-02 (1.18e-02)
Percent Unemployed	-	-	-	-	-8.90e-02* (3.78e-02)
Housing Burden	-	-	-	-	9.74e-03 (9.58e-03)

Percentage of gray-sky-weather restorations made within 24 hours

Table A - 12. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of gray-sky-weather restorations made within 24 hours (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of gray-sky-weather restorations made within 24 hours	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	4.02e-03 (1.08e-02)	2.54e-03 (1.38e-02)	2.54e-02 (1.51e-02)	-9.74e-03 (1.36e-02)	1.12e-02 (1.72e-02)
Poverty	-	1.98e-03 (1.15e-02)	-	-	1.26e-02 (1.68e-02)
Median Household Income, Past 12 Months (per $10,000)	-	-	3.41e-01* (1.69e-01)	-	4.61e-01* (2.11e-01)
Population Density (People per Sq. Mile)	-	-	-	2.92e-02 (1.75e-02)	2.38e-02 (1.81e-02)
Percent Unemployed	-	-	-	-	-8.36e-02 (5.59e-02)
Housing Burden	-	-	-	-	1.42e-02 (1.40e-02)

Percentage of all-weather restorations made within 36 hours

Table A - 13. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of all-weather restorations made within 36 hours (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of all-weather restorations made within 36 hours	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	1.08e-02 (6.21e-03)	1.33e-02 (8.11e-03)	1.57e-02 (9.09e-03)	4.28e-03 (7.74e-03)	1.35e-02 (1.02e-02)
Poverty	-	-3.18e-03 (6.60e-03)	-	-	3.80e-04 (9.55e-03)
Median Household Income, Past 12 Months (per $10,000)	-	-	7.40e-02 (9.92e-02)	-	-1.23e-02 (1.21e-01)
Population Density (People per Sq. Mile)	-	-	-	1.34e-02 (9.52e-03)	1.40e-02 (9.84e-03)
Percent Unemployed	-	-	-	-	-1.10e-01*** (3.14e-02)
Housing Burden	-	-	-	-	2.70e-03 (7.99e-03)

Percentage of catastrophic-weather restorations made within 48 hours

Table A - 14. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of catastrophic-weather restorations made within 48 hours (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of catastrophic-weather restorations made within 48 hours	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-2.93e-02 (1.60e-02)	-3.24e-02 (2.06e-02)	-2.91e-02 (2.35e-02)	-3.67e-02 (2.01e-02)	-2.82e-02 (2.67e-02)
Poverty	-	4.11e-03 (1.69e-02)	-	-	1.12e-02 (2.41e-02)
Median Household Income, Past 12 Months (per $10,000)	-	-	2.02e-03 (2.62e-01)	-	-1.27e-01 (3.11e-01)
Population Density (People per Sq. Mile)	-	-	-	1.54e-02 (2.54e-02)	1.23e-02 (2.62e-02)
Percent Unemployed	-	-	-	-	-2.67e-01** (8.41e-02)
Housing Burden	-	-	-	-	7.15e-03 (2.03e-02)

Total Customer Interruptions

Table A - 15. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of Total Customer Interruptions (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Total Customer Interruptions	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-2.89e+01*** (1.34e+00)	-2.60e+01*** (1.78e+00)	-2.20e+01*** (2.03e+00)	-2.11e+01*** (1.65e+00)	-1.74e+01*** (2.23e+00)

Poverty	-	-3.66e+00* (1.44e+00)	-	-	-2.51e+00 (2.04e+00)
Median Household Income, Past 12 Months (per $10,000)	-	-	1.00e+02*** (2.21e+01)	-	1.19e+02*** (2.62e+01)
Population Density (People per Sq. Mile)	-	-	-	-1.61e+01*** (2.02e+00)	-1.71e+01*** (2.08e+00)
Percent Unemployed	-	-	-	-	8.43e+00 (6.65e+00)
Housing Burden	-	-	-	-	7.37e+00*** (1.71e+00)

Unique Customers with an Interruption

Table A - 16. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of Unique Customers with an Interruption (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Unique Customers with an Interruption	**1**	**2**	**3**	**4**	**5**
MiEJScreen Overall Score	-9.39e+00*** (4.55e-01)	-6.50e+00*** (6.01e-01)	-4.55e+00*** (6.83e-01)	-6.91e+00*** (5.62e-01)	-2.90e+00*** (7.51e-01)
Poverty	-	-3.55e+00*** (4.86e-01)	-	-	-2.85e+00*** (6.87e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	7.03e+01*** (7.45e+00)	-	6.08e+01*** (8.83e+00)
Population Density (People per Sq. Mile)	-	-	-	-5.10e+00*** (6.84e-01)	-4.90e+00*** (7.01e-01)
Percent Unemployed	-	-	-	-	-4.91e+00* (2.24e+00)
Housing Burden	-	-	-	-	3.63e+00*** (5.75e-01)

B. Census Tract-Level Reliability Regression Results Considering Percent Minority Percentile

SAIDI including MEDs

Table A - 17. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIDI including MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIDI including MEDs	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-5.82e+00*** (5.45e-01)	-5.57e+00*** (7.09e-01)	-4.68e+00*** (6.39e-01)	-3.93e+00*** (6.36e-01)	-4.65e+00*** (7.48e-01)
Poverty	-	-3.69e-01 (6.65e-01)	-	-	2.40e+00* (9.97e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	2.76e+01*** (8.06e+00)	-	4.26e+01*** (1.10e+01)
Population Density	-	-	-	-5.15e+00*** (8.99e-01)	-4.91e+00*** (9.60e-01)
Percent Unemployed	-	-	-	-	1.18e+01*** (3.17e+00)
Housing Burden	-	-	-	-	-5.30e-01 (8.07e-01)

SAIFI including MEDs

Table A - 18. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIFI including MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
SAIFI including MEDs	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-8.66e-03*** (5.41e-04)	-8.55e-03*** (7.06e-04)	-7.11e-03*** (6.35e-04)	-5.99e-03*** (6.29e-04)	-7.19e-03*** (7.40e-04)
Poverty	-	-1.65e-04 (6.63e-04)	-	-	3.88e-03*** (9.87e-04)

Median Household Income, Past 12 Months (per $10,000)	-	-	3.73e-02*** (8.03e-03)	-	6.04e-02*** (1.09e-02)
Population Density	-	-	-	-7.30e-03*** (8.90e-04)	-7.12e-03*** (9.49e-04)
Percent Unemployed	-	-	-	-	1.58e-02*** (3.13e-03)
Housing Burden	-	-	-	-	-7.36e-04 (7.98e-04)

CAIDI excluding MEDs

Table A - 19. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CAIDI excluding MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CAIDI excluding MEDs	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-2.05e-01** (6.24e-02)	-1.19e-01 (8.05e-02)	-1.71e-01* (7.27e-02)	-1.20e-01 (7.29e-02)	-1.02e-01 (8.55e-02)
Poverty	-	-1.27e-01 (7.55e-02)	-	-	-4.80e-02 (1.14e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	8.31e-01 (9.17e-01)	-	1.76e-01 (1.27e+00)
Population Density	-	-	-	-2.32e-01* (1.03e-01)	-1.68e-01 (1.10e-01)
Percent Unemployed	-	-	-	-	1.41e+00*** (3.64e-01)
Housing Burden	-	-	-	-	-2.03e-01* (9.25e-02)

CAIDI including MEDs

Table A - 20. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CAIDI including MEDs (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CAIDI including MEDs	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-8.67e-01*** (2.17e-01)	-6.87e-01* (2.78e-01)	-6.10e-01* (2.51e-01)	-4.88e-01 (2.54e-01)	-5.43e-01 (2.96e-01)
Poverty	-	-2.70e-01 (2.61e-01)	-	-	3.31e-01 (3.96e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	6.39e+00* (3.17e+00)	-	8.70e+00* (4.41e+00)
Population Density	-	-	-	-1.03e+00** (3.60e-01)	-8.46e-01* (3.84e-01)
Percent Unemployed	-	-	-	-	4.21e+00*** (1.27e+00)
Housing Burden	-	-	-	-	-4.17e-01 (3.22e-01)

CELID-5

Table A - 21. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CELID-5 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CELID-5	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-2.19e-03*** (1.52e-04)	-1.92e-03*** (1.97e-04)	-1.65e-03*** (1.78e-04)	-1.52e-03*** (1.78e-04)	-1.57e-03*** (2.08e-04)
Poverty	-	-4.03e-04* (1.85e-04)	-	-	7.55e-04** (2.77e-04)
Median Household Income, Past 12 Months (per $10,000)	-	-	1.31e-02*** (2.25e-03)	-	1.65e-02*** (3.08e-03)
Population Density	-	-	-	-1.84e-03*** (2.52e-04)	-1.59e-03*** (2.68e-04)

Percent Unemployed	-	-	-	-	3.31e-03*** (8.85e-04)
Housing Burden	-	-	-	-	-2.76e-04 (2.25e-04)

CELID-24

Table A - 22. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CELID-24 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CELID-24	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-9.33e-04*** (1.09e-04)	-8.99e-04*** (1.41e-04)	-7.42e-04*** (1.28e-04)	-5.90e-04*** (1.28e-04)	-7.04e-04*** (1.50e-04)
Poverty	-	-5.04e-05 (1.33e-04)	-	-	4.74e-04* (2.00e-04)
Median Household Income, Past 12 Months (per $10,000)	-	-	4.68e-03** (1.61e-03)	-	6.93e-03** (2.22e-03)
Population Density	-	-	-	-9.38e-04*** (1.81e-04)	-9.00e-04*** (1.93e-04)
Percent Unemployed	-	-	-	-	1.57e-03* (6.38e-04)
Housing Burden	-	-	-	-	-1.25e-04 (1.62e-04)

CEMI-4

Table A - 23. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-4 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-4	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-1.24e-03*** (8.78e-05)	-1.26e-03*** (1.15e-04)	-1.07e-03*** (1.03e-04)	-8.93e-04*** (1.02e-04)	-1.09e-03*** (1.20e-04)
Poverty	-	1.98e-05 (1.07e-04)	-	-	4.98e-04** (1.61e-04)

Median Household Income, Past 12 Months (per $10,000)	-	-	4.10e-03** (1.30e-03)	-	7.32e-03*** (1.78e-03)
Population Density	-	-	-	-9.57e-04*** (1.45e-04)	-9.64e-04*** (1.55e-04)
Percent Unemployed	-	-	-	-	2.32e-03*** (5.09e-04)
Housing Burden	-	-	-	-	-8.75e-05 (1.30e-04)

CEMI-5

Table A - 24. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-5 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-5	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-7.33e-04*** (6.41e-05)	-7.90e-04*** (8.35e-05)	-6.88e-04*** (7.52e-05)	-5.16e-04*** (7.47e-05)	-6.85e-04*** (8.80e-05)
Poverty	-	8.34e-05 (7.84e-05)	-	-	3.06e-04** (1.17e-04)
Median Household Income, Past 12 Months (per $10,000)	-	-	1.10e-03 (9.50e-04)	-	3.03e-03* (1.30e-03)
Population Density	-	-	-	-5.94e-04*** (1.06e-04)	-6.50e-04*** (1.13e-04)
Percent Unemployed	-	-	-	-	1.56e-03*** (3.72e-04)
Housing Burden	-	-	-	-	-6.01e-05 (9.48e-05)

CEMI-7

Table A - 25. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-7 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-7	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-2.23e-04*** (3.38e-05)	-2.46e-04*** (4.41e-05)	-2.10e-04*** (3.97e-05)	-1.68e-04*** (3.94e-05)	-2.17e-04*** (4.66e-05)
Poverty	-	3.49e-05 (4.14e-05)	-	-	1.30e-04* (6.21e-05)
Median Household Income, Past 12 Months (per $10,000)	-	-	2.99e-04 (5.02e-04)	-	9.57e-04 (6.87e-04)
Population Density	-	-	-	-1.48e-04** (5.57e-05)	-1.56e-04** (5.96e-05)
Percent Unemployed	-	-	-	-	5.00e-04* (1.97e-04)
Housing Burden	-	-	-	-	-6.80e-05 (5.02e-05)

CEMI-10

Table A - 26. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of CEMI-10 (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
CEMI-10	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-4.06e-05** (1.51e-05)	-5.89e-05** (1.96e-05)	-4.38e-05* (1.77e-05)	-4.07e-05* (1.76e-05)	-5.34e-05* (2.08e-05)
Poverty	-	2.69e-05 (1.84e-05)	-	-	6.20e-05* (2.77e-05)
Median Household Income, Past 12 Months (per $10,000)	-	-	-7.79e-05 (2.24e-04)	-	1.70e-04 (3.07e-04)
Population Density	-	-	-	2.25e-07 (2.49e-05)	-2.05e-06 (2.67e-05)
Percent Unemployed	-	-	-	-	5.93e-05 (8.79e-05)

Housing Burden	-	-	-	-	-4.14e-05 (2.24e-05)

Percentage of normal-weather restorations made within 8 hours

Table A - 27. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of normal-weather restorations made within 8 hours (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of normal-weather restorations made within 8 hours	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-2.55e-03 (6.46e-03)	-1.02e-02 (8.19e-03)	-3.07e-03 (7.44e-03)	-2.30e-03 (7.57e-03)	-7.40e-03 (8.79e-03)
Poverty	-	1.17e-02 (7.69e-03)	-	-	1.60e-02 (1.18e-02)
Median Household Income, Past 12 Months (per $10,000)	-	-	-1.33e-02 (9.38e-02)	-	9.22e-02 (1.32e-01)
Population Density	-	-	-	-6.73e-04 (1.08e-02)	-6.32e-03 (1.15e-02)
Percent Unemployed	-	-	-	-	-8.04e-02* (3.80e-02)
Housing Burden	-	-	-	-	1.20e-02 (9.59e-03)

Percentage of gray-sky-weather restorations made within 24 hours

Table A - 28. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of gray-sky-weather restorations made within 24 hours (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of gray-sky-weather restorations made within 24 hours	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	1.77e-03 (9.50e-03)	-6.42e-04 (1.21e-02)	9.58e-03 (1.09e-02)	-8.42e-03 (1.12e-02)	-6.13e-03 (1.30e-02)
Poverty	-	3.67e-03 (1.15e-02)	-	-	1.43e-02 (1.73e-02)
Median Household Income, Past 12 Months (per $10,000)	-	-	2.00e-01 (1.39e-01)	-	4.07e-01* (1.92e-01)
Population Density	-	-	-	2.81e-02 (1.64e-02)	3.10e-02 (1.73e-02)
Percent Unemployed	-	-	-	-	-7.59e-02 (5.63e-02)
Housing Burden	-	-	-	-	1.60e-02 (1.40e-02)

Percentage of all-weather restorations made within 36 hours

Table A - 29. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of all-weather restorations made within 36 hours (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of all-weather restorations made within 36 hours	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	1.44e-03 (5.37e-03)	-1.65e-03 (6.84e-03)	-7.61e-04 (6.21e-03)	-6.39e-03 (6.30e-03)	-3.57e-03 (7.33e-03)
Poverty	-	4.69e-03 (6.44e-03)	-	-	1.58e-03 (9.81e-03)

Median Household Income, Past 12 Months (per $10,000)	-	-	-5.53e-02 (7.83e-02)	-	-7.84e-02 (1.09e-01)
Population Density	-	-	-	2.13e-02* (8.96e-03)	2.00e-02* (9.53e-03)
Percent Unemployed	-	-	-	-	-1.04e-01** (3.16e-02)
Housing Burden	-	-	-	-	4.56e-03 (7.98e-03)

Percentage of catastrophic-weather restorations made within 48 hours

Table A - 30. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of the percentage of catastrophic-weather restorations made within 48 hours (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Percentage of catastrophic-weather restorations made within 48 hours	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-3.21e-02* (1.38e-02)	-3.84e-02* (1.75e-02)	-3.01e-02 (1.58e-02)	-3.82e-02* (1.63e-02)	-3.47e-02 (1.88e-02)
Poverty	-	9.74e-03 (1.67e-02)	-	-	2.23e-02 (2.48e-02)
Median Household Income, Past 12 Months (per $10,000)	-	-	5.20e-02 (2.03e-01)	-	4.44e-02 (2.76e-01)
Population Density	-	-	-	1.66e-02 (2.37e-02)	1.47e-02 (2.51e-02)
Percent Unemployed	-	-	-	-	-2.56e-01** (8.44e-02)
Housing Burden	-	-	-	-	9.52e-03 (2.04e-02)

Total Customer Interruptions

Table A - 31. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of Total Customer Interruptions (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

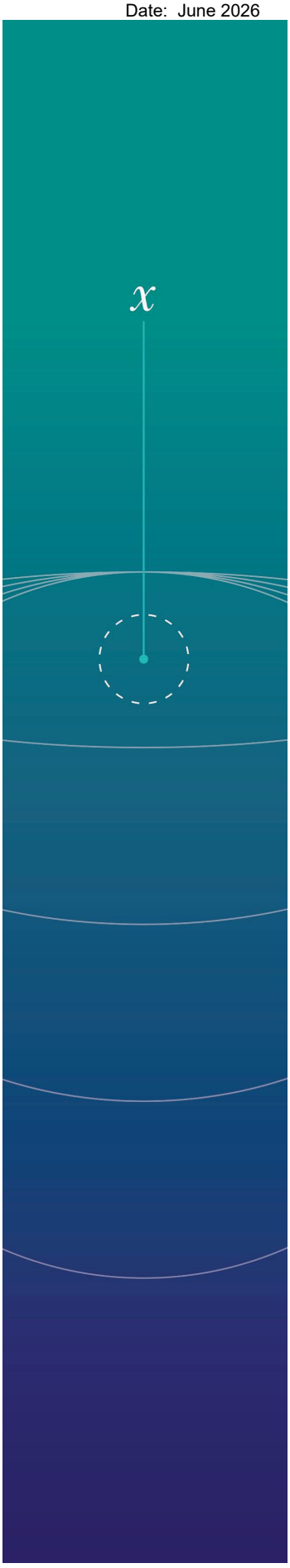
	Model Number				
Total Customer Interruptions	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-2.11e+01*** (1.17e+00)	-1.56e+01*** (1.52e+00)	-1.30e+01*** (1.36e+00)	-1.31e+01*** (1.35e+00)	-1.18e+01*** (1.58e+00)
Poverty	-	-8.11e+00*** (1.43e+00)	-	-	1.21e+00 (2.11e+00)
Median Household Income, Past 12 Months (per $10,000)	-	-	1.94e+02*** (1.72e+01)	-	2.15e+02*** (2.34e+01)
Population Density	-	-	-	-2.18e+01*** (1.91e+00)	-1.88e+01*** (2.03e+00)
Percent Unemployed	-	-	-	-	1.00e+01 (6.68e+00)
Housing Burden	-	-	-	-	7.26e+00*** (1.71e+00)

Unique Customers with an Interruption

Table A - 32. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of Unique Customers with an Interruption (with county-level and year fixed effects). All models include Percent Minority Percentile as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

	Model Number				
Unique Customers with an Interruption	**1**	**2**	**3**	**4**	**5**
Percent Minority Percentile	-6.57e+00*** (3.96e-01)	-3.04e+00*** (5.11e-01)	-2.93e+00*** (4.57e-01)	-3.94e+00*** (4.58e-01)	-1.88e+00*** (5.33e-01)
Poverty	-	-5.18e+00*** (4.81e-01)	-	-	-2.27e+00** (7.11e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	8.82e+01*** (5.78e+00)	-	7.67e+01*** (7.87e+00)

Population Density	-	-	-	-7.20e+00*** (6.48e-01)	-5.21e+00*** (6.83e-01)
Percent Unemployed	-	-	-	-	-4.70e+00* (2.25e+00)
Housing Burden	-	-	-	-	3.60e+00*** (5.75e-01)



Appendix B

Feeder-Level Reliability Regression Results: Supplementary Material

Feeder-Level Reliability Regression Results: Supplementary Material

This appendix contains supplementary information on the feeders in Consumers' electric distribution systems. Figure B1 through Figure B6 map the 2010 Census tracts within Consumers' service territory served by feeders of each voltage level and configuration.

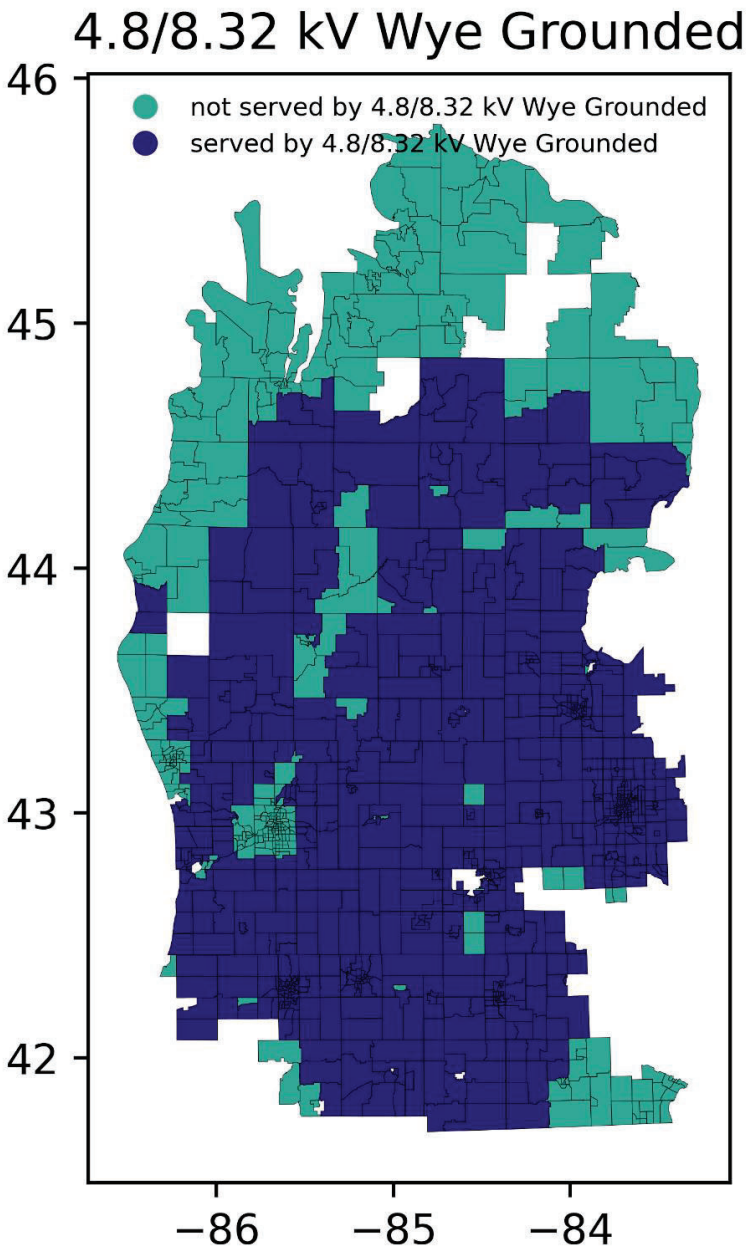


Figure B1. Map of 2010 census tracts in Consumers' service territory served by 4.8/8.32 kV Wye Grounded feeders.

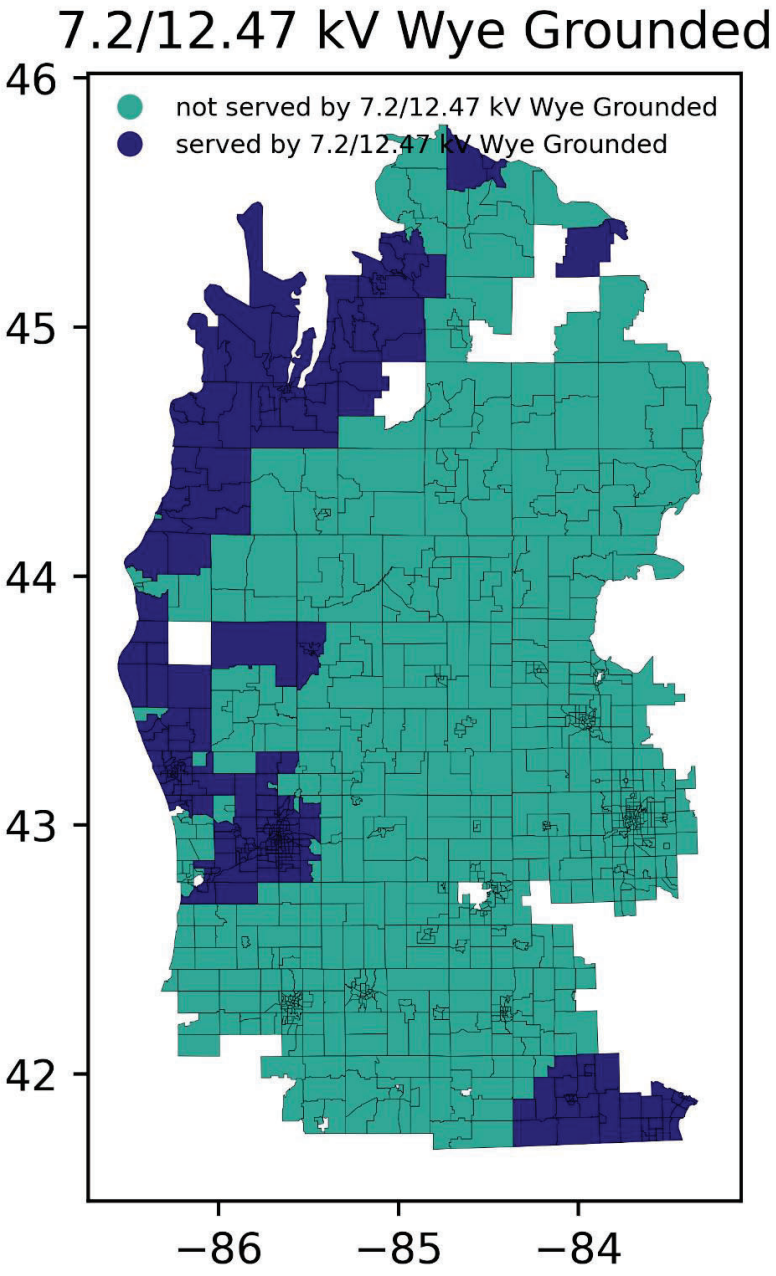


Figure B2. Map of 2010 census tracts in Consumers' service territory served by 7.2/12.47 kV Wye Grounded feeders.

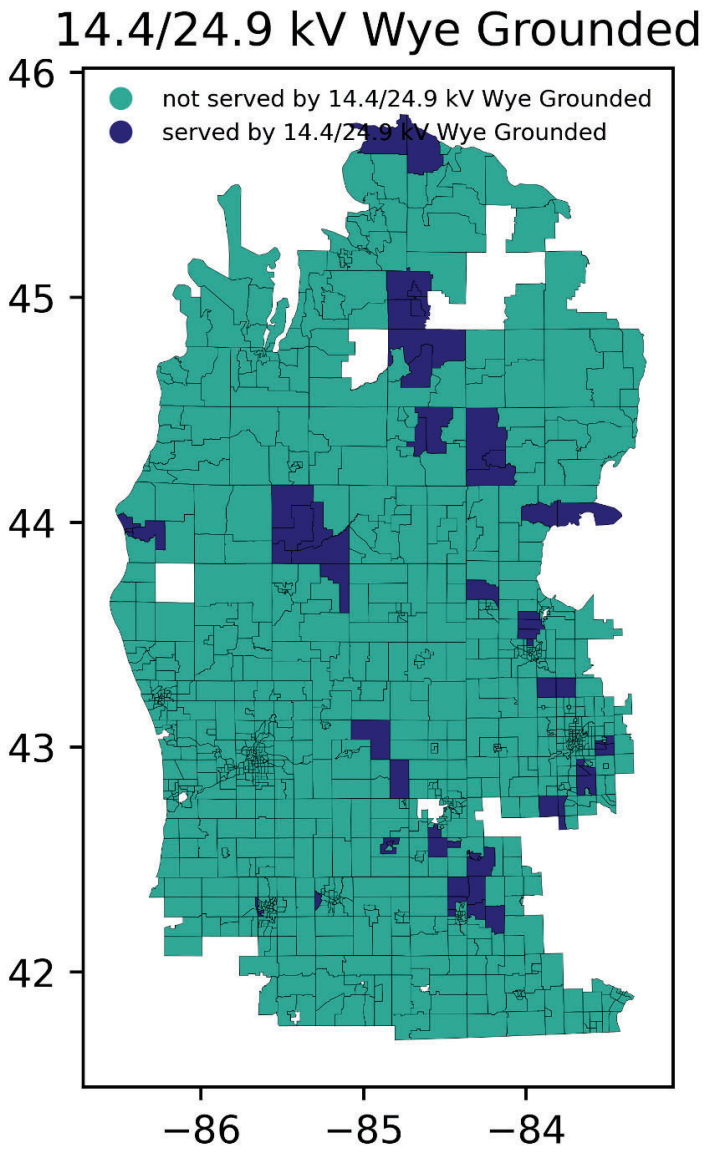


Figure B3. Map of 2010 census tracts in Consumers' service territory served by 14.4/24.9 kV Wye Grounded feeders.

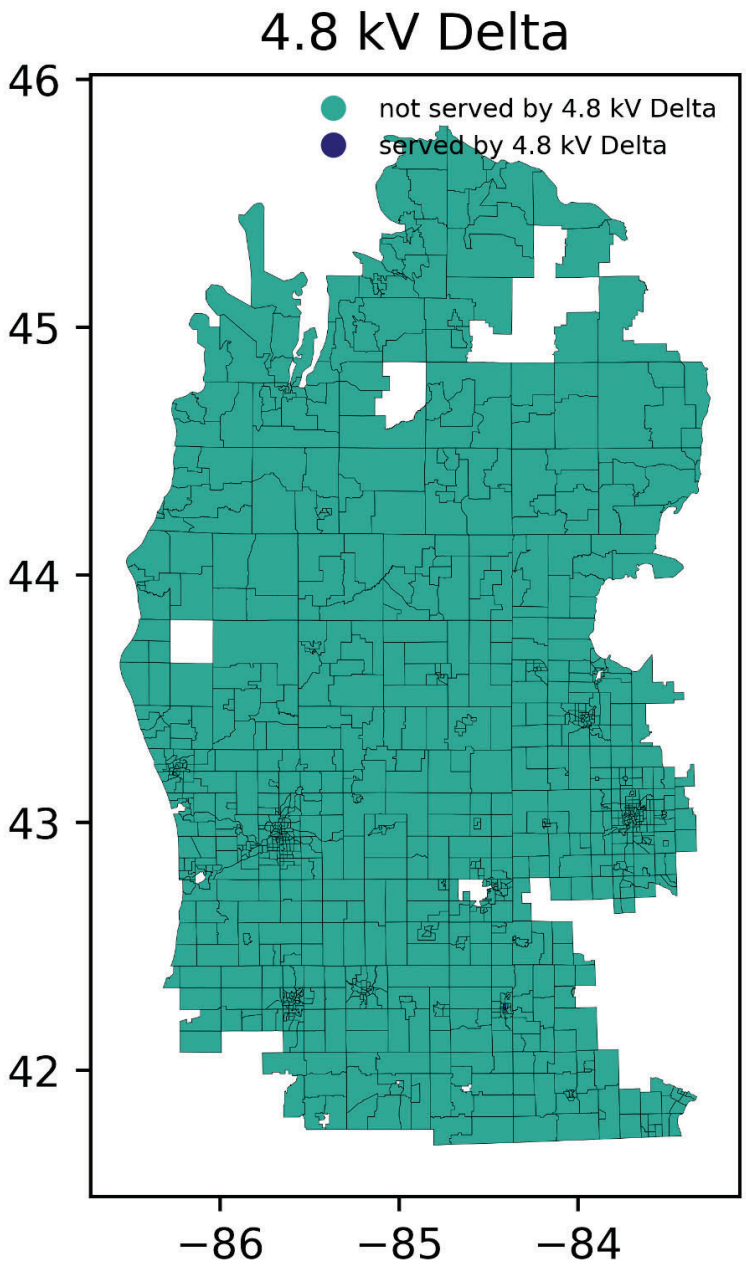


Figure B4. Map of 2010 census tracts in Consumers' service territory served by 4.8kV Delta feeders.

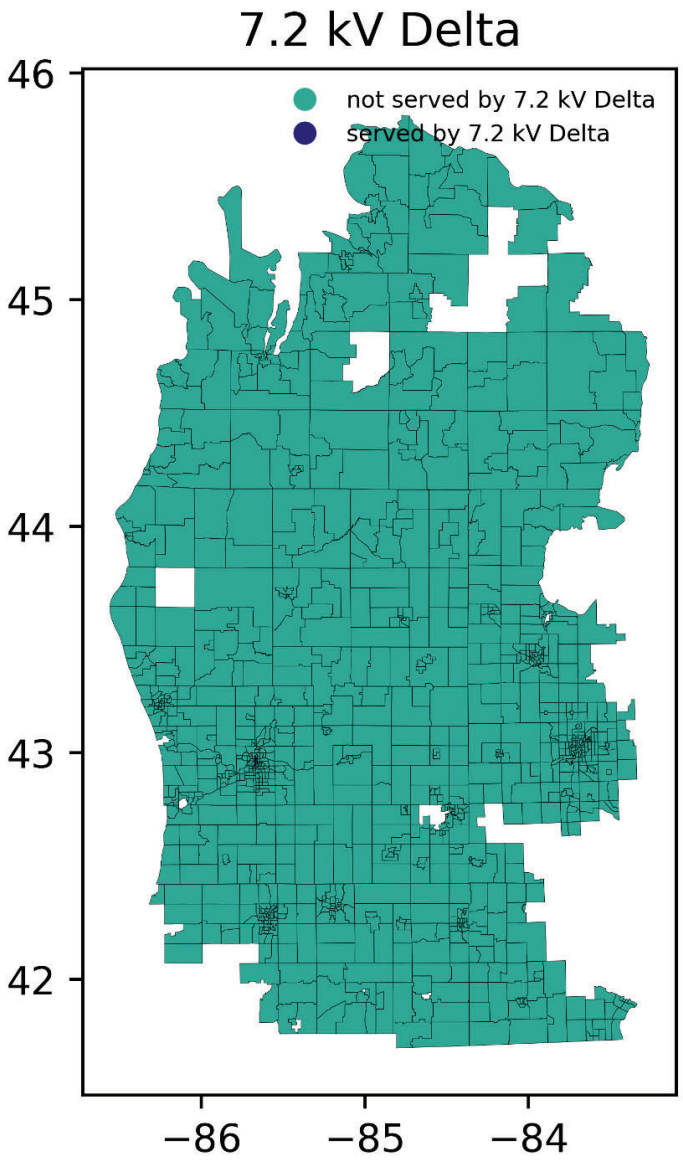


Figure B5. Map of 2010 census tracts in Consumers' service territory served by 7.2 kV Delta feeders.

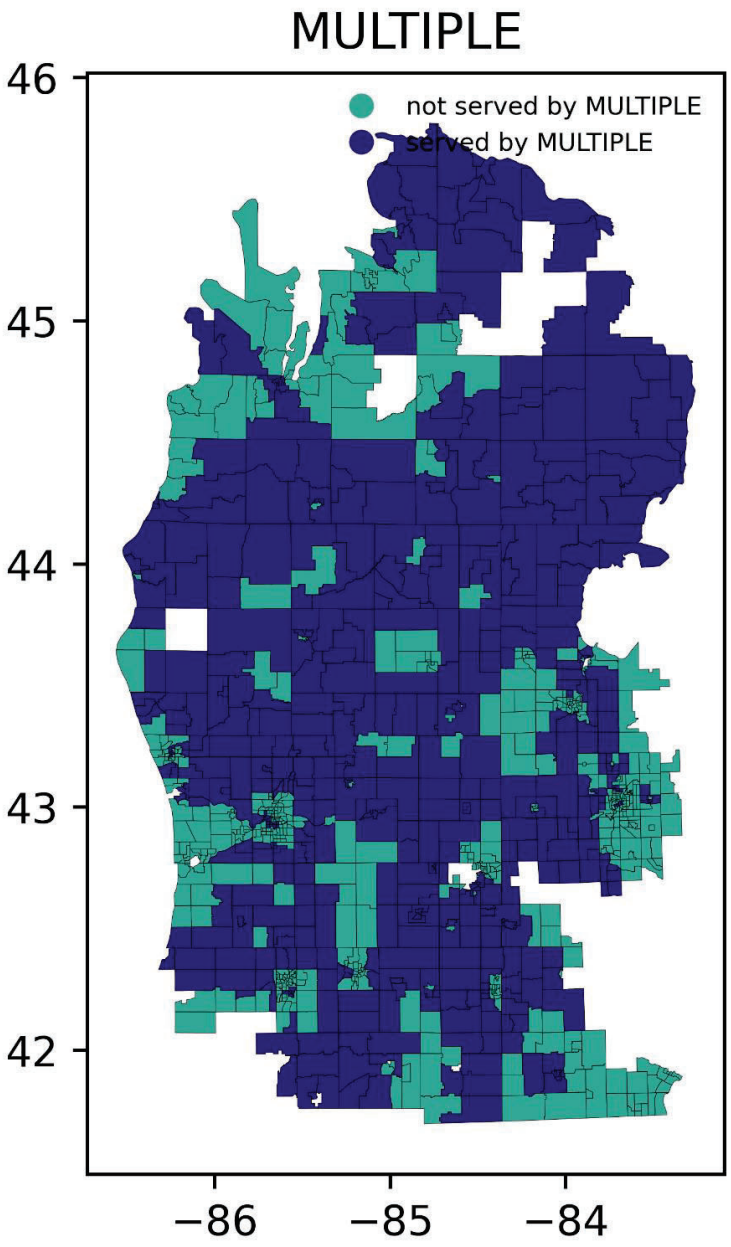


Figure B6. Map of 2010 census tracts in Consumers' service territory served by MULTIPLE feeders.

Exponent®

CMS Reliability and Disconnections Regression Analysis

Overview and Observations

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4 May 2026

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Executive Summary

Reliability and Disconnections Regression Analysis

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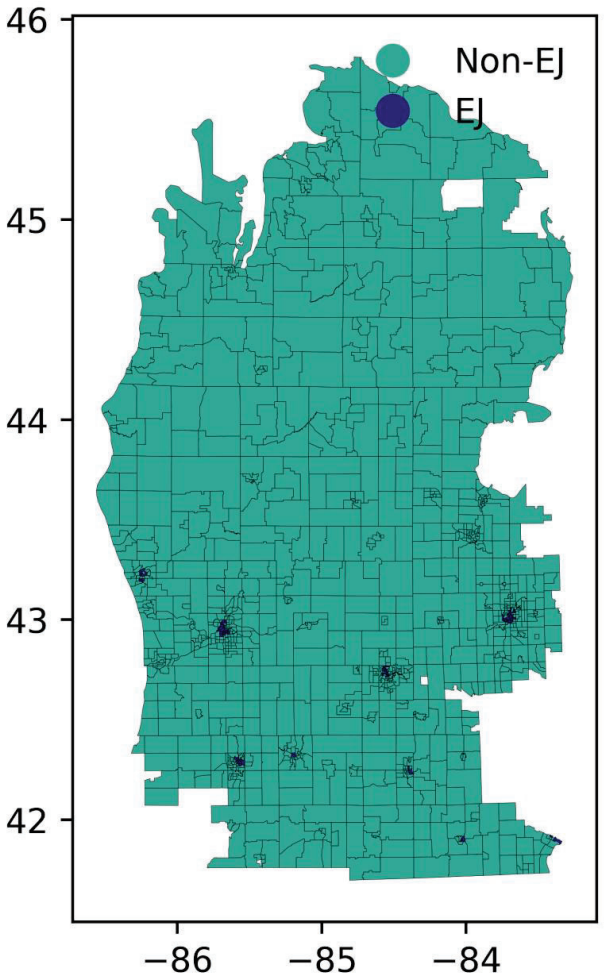
Background

- March 2024 MPSC Order: use regression analysis to assess whether customers in Environmental Justice (EJ) communities experience lower levels of distribution reliability than customers in other communities.
- March 2025 MPSC Order: include residential involuntary disconnections for non-payment in the regression analysis.
- The aim of the current analysis is to update the reliability and disconnections analyses that were previously run (the “2025 Analysis”) with an additional year of data.

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Groups of Customers

- EJ and Non-EJ census tracts
  - EJ if MiEJScreen Overall Score > 80; and
  - Non-EJ otherwise.
- Urban and Rural census tracts
- Low-Income and High-Income census tracts
- High-Percent-Minority-Percentile and Low-Percent-Minority-Percentile census tracts



EJ and non-EJ communities within Consumers' service territory.

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Summary of Observations: Reliability

Reliability

- Are there statistically significant differences in the average reliability of different groups of customers?
- What correlations exist between communities' demographic characteristics and their reliability?
- What correlations exist between circuit characteristics and their reliability?

When there are statistically significant differences in average reliability, EJ census tracts tend to have better average reliability than Non-EJ census tracts.

Increasing MiEJScreen Overall Score and increasing Percent Minority Percentile are often associated with improving reliability, when all other variables and factors are held constant.

Whether a feeder serves an EJ census tract does not have a statistically significant correlation with its reliability.

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Summary of Observations: Disconnections

Disconnections

- What correlations exist between communities' demographic characteristics and rates of residential involuntary disconnections for non-payment?

Energy Burden (% Income), Electricity has a statistically significant correlation with disconnection rate that is greater than those of the other independent variables in the model.

When all other variables and factors are held constant, increasing Percentage Minority Population in a census tract is statistically significant and associated with increasing disconnection rate.

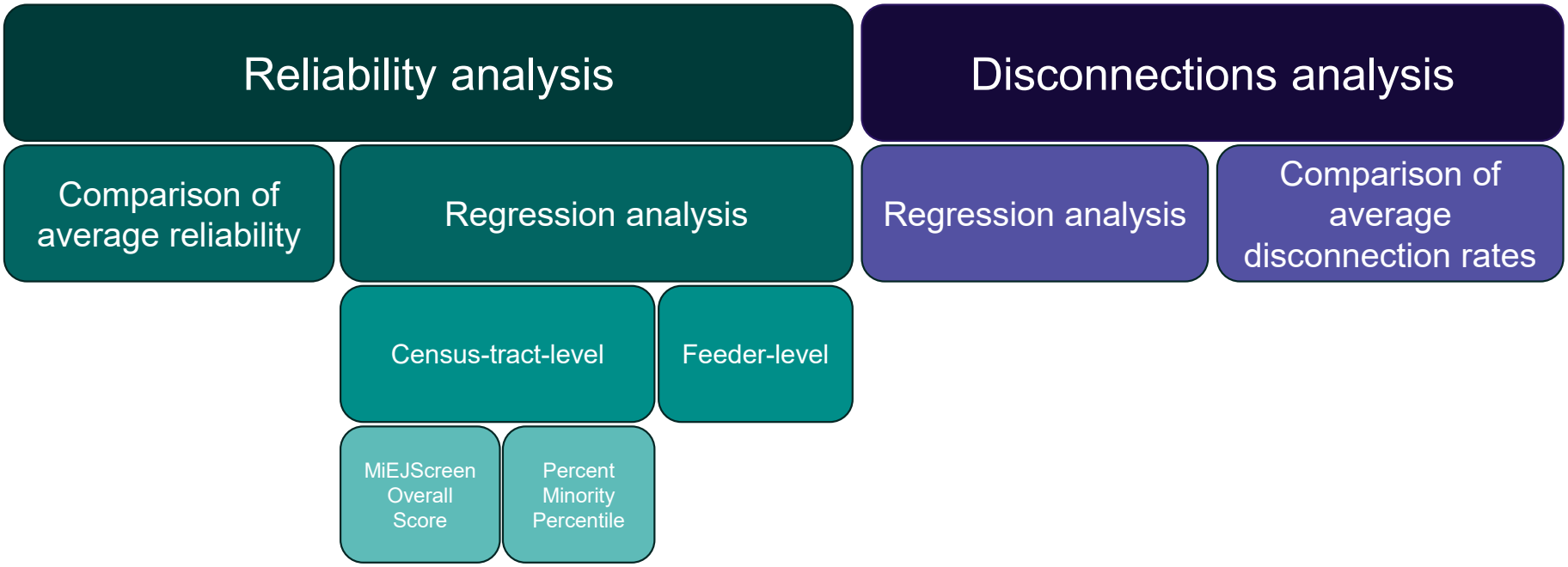
Percentage Below Poverty; Population Density; Median Home Value; Percentage of Homes Built After 1990; and Percentage Renters also have statistically significant correlations with disconnection rate.

- Do customers with the worst reliability also experience higher rates of disconnections than other customers?

No; the census tracts with the worst reliability tend to have lower average disconnection rates than the rest of the census tracts.

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Analysis Roadmap



Agenda



1. Executive Summary
2. Comparisons of Average Reliability
3. Regression Analysis Results: Census Tract-Level Reliability
4. Regression Analysis Results: Feeder-Level Reliability
5. Regression Analysis Results: Disconnection Rates
6. Key Takeaways & Next Steps

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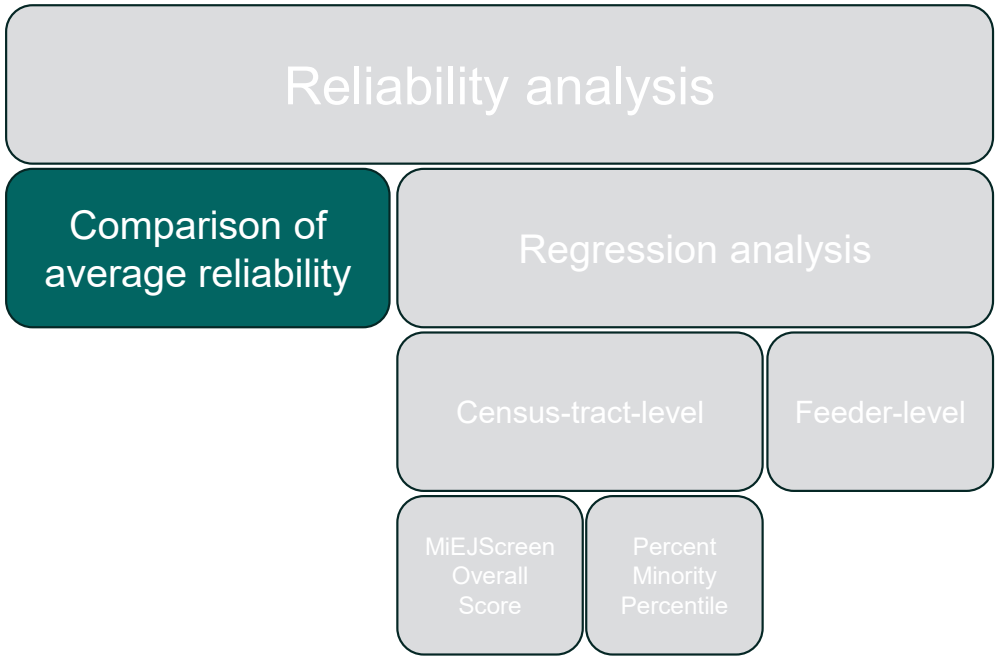
2. Comparisons of Average Reliability

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Comparison of Average Reliability

Are there statistically significant differences in the average reliability of different groups of customers?

- **Method**: Used binary difference-in-means t-test to compare average reliability (by 18 different metrics).



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Comparison of Average Reliability: EJ and Non-EJ

- When there are statistically significant differences in the mean reliability of EJ and non-EJ census tracts, EJ census tracts consistently experience better average reliability.
  - **Exception**: In 2025, the percentage of catastrophic-weather restorations made within 48 hours is the only metric by which Non-EJ tracts experience statistically significant better average reliability.

Excerpt of Table 5.

Reliability Metric	Year	Non-EJ_ Mean	EJ Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.13E+03	8.90E+02	2.37E+02	6.62E-03	TRUE	EJ
	2021	1.23E+03	8.19E+02	4.14E+02	5.55E-07	TRUE	EJ
	2022	1.12E+03	8.52E+02	2.64E+02	2.86E-03	TRUE	EJ
	2023	1.16E+03	8.10E+02	3.52E+02	6.20E-05	TRUE	EJ
	2024	1.10E+03	7.97E+02	3.08E+02	2.97E-04	TRUE	EJ
	2025	1.14E+03	6.75E+02	4.60E+02	2.91E-08	TRUE	EJ
Total Customer Interruptions	2020	2.39E+03	1.82E+03	5.72E+02	1.33E-02	TRUE	EJ
	2021	2.91E+03	1.39E+03	1.52E+03	5.83E-16	TRUE	EJ
	2022	2.31E+03	1.77E+03	5.42E+02	5.06E-02	FALSE	N/A
	2023	2.50E+03	1.56E+03	9.40E+02	3.44E-04	TRUE	EJ
	2024	2.44E+03	1.43E+03	1.01E+03	1.56E-06	TRUE	EJ
	2025	2.53E+03	1.14E+03	1.39E+03	8.49E-13	TRUE	EJ
SAIDI including MEDs	2020	5.24E+02	2.85E+02	2.39E+02	5.69E-05	TRUE	EJ
	2021	9.66E+02	3.06E+02	6.60E+02	3.74E-28	TRUE	EJ
	2022	4.56E+02	2.90E+02	1.66E+02	1.49E-04	TRUE	EJ
	2023	9.36E+02	4.76E+02	4.60E+02	2.50E-05	TRUE	EJ
	2024	4.90E+02	2.89E+02	2.00E+02	1.40E-05	TRUE	EJ
	2025	9.90E+02	5.86E+02	4.03E+02	5.20E-04	TRUE	EJ
SAIDI excluding MEDs	2020	1.99E+02	1.38E+02	6.08E+01	5.05E-05	TRUE	EJ
	2021	2.45E+02	1.34E+02	1.11E+02	3.55E-07	TRUE	EJ
	2022	1.84E+02	1.28E+02	5.60E+01	2.02E-04	TRUE	EJ
	2023	1.84E+02	1.10E+02	7.36E+01	6.37E-10	TRUE	EJ
	2024	1.64E+02	1.06E+02	5.85E+01	5.07E-05	TRUE	EJ
	2025	1.78E+02	1.30E+02	4.85E+01	1.48E-01	FALSE	N/A
SAIFI including MEDs	2020	1.33E+00	1.16E+00	1.75E-01	1.01E-01	FALSE	N/A
	2021	1.65E+00	1.05E+00	5.98E-01	2.69E-08	TRUE	EJ
	2022	1.27E+00	1.20E+00	7.19E-02	6.35E-01	FALSE	N/A
	2023	1.40E+00	1.04E+00	3.57E-01	5.60E-03	TRUE	EJ
	2024	1.33E+00	9.16E-01	4.14E-01	1.27E-04	TRUE	EJ
	2025	1.53E+00	8.39E-01	6.91E-01	3.80E-08	TRUE	EJ
SAIFI excluding MEDs	2020	1.01E+00	9.36E-01	7.63E-02	4.32E-01	FALSE	N/A
	2021	1.09E+00	7.92E-01	2.93E-01	1.41E-03	TRUE	EJ
	2022	9.61E-01	8.85E-01	7.55E-02	4.25E-01	FALSE	N/A
	2023	9.76E-01	7.85E-01	1.91E-01	2.75E-02	TRUE	EJ
	2024	9.03E-01	6.90E-01	2.13E-01	1.78E-02	TRUE	EJ
	2025	9.37E-01	5.97E-01	3.40E-01	9.85E-04	TRUE	EJ

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Comparison of Average Reliability: Urban and Rural

- When there are statistically significant differences in the mean reliability of Urban and Rural census tracts, Urban census tracts consistently experience better average reliability.
  - **Exception**: In 2025, the percentage of catastrophic-weather restorations made within 48 hours is the only metric by which Rural tracts experience statistically significant better average reliability.

Excerpt of Table 6.

Reliability Metric	Year	Rural Mean	Urban Mean	Difference	*p*-value	Significant?	Better?
Unique Customers with an Interruption	2020	1.24E+03	9.41E+02	3.03E+02	1.30E-11	TRUE	urban
	2021	1.37E+03	1.01E+03	3.58E+02	7.08E-14	TRUE	urban
	2022	1.22E+03	9.51E+02	2.65E+02	1.57E-08	TRUE	urban
	2023	1.24E+03	1.01E+03	2.32E+02	1.89E-06	TRUE	urban
	2024	1.22E+03	9.15E+02	3.04E+02	1.53E-10	TRUE	urban
	2025	1.26E+03	9.16E+02	3.43E+02	2.09E-12	TRUE	urban
Total Customer Interruptions	2020	2.91E+03	1.64E+03	1.28E+03	2.32E-25	TRUE	urban
	2021	3.66E+03	1.72E+03	1.94E+03	1.57E-43	TRUE	urban
	2022	2.76E+03	1.65E+03	1.11E+03	9.54E-20	TRUE	urban
	2023	2.93E+03	1.82E+03	1.11E+03	2.21E-17	TRUE	urban
	2024	2.99E+03	1.57E+03	1.42E+03	9.00E-25	TRUE	urban
	2025	3.20E+03	1.47E+03	1.74E+03	2.90E-34	TRUE	urban
SAIDI including MEDs	2020	6.65E+02	3.07E+02	3.58E+02	6.84E-23	TRUE	urban
	2021	1.35E+03	3.80E+02	9.65E+02	4.73E-55	TRUE	urban
	2022	5.86E+02	2.63E+02	3.23E+02	3.78E-36	TRUE	urban
	2023	1.13E+03	6.24E+02	5.05E+02	1.08E-09	TRUE	urban
	2024	6.20E+02	2.91E+02	3.29E+02	2.51E-21	TRUE	urban
	2025	1.30E+03	5.28E+02	7.72E+02	8.48E-22	TRUE	urban
SAIDI excluding MEDs	2020	2.49E+02	1.25E+02	1.24E+02	1.63E-26	TRUE	urban
	2021	3.15E+02	1.38E+02	1.77E+02	2.66E-31	TRUE	urban
	2022	2.30E+02	1.16E+02	1.14E+02	2.19E-31	TRUE	urban
	2023	2.18E+02	1.30E+02	8.81E+01	9.70E-20	TRUE	urban
	2024	2.08E+02	9.83E+01	1.10E+02	1.04E-30	TRUE	urban
	2025	2.32E+02	1.01E+02	1.31E+02	2.04E-32	TRUE	urban
SAIFI including MEDs	2020	1.62E+00	9.26E-01	6.96E-01	2.67E-34	TRUE	urban
	2021	2.09E+00	9.90E-01	1.10E+00	1.21E-67	TRUE	urban
	2022	1.53E+00	9.17E-01	6.09E-01	4.10E-30	TRUE	urban
	2023	1.62E+00	1.05E+00	5.69E-01	2.66E-21	TRUE	urban
	2024	1.63E+00	8.77E-01	7.55E-01	1.01E-34	TRUE	urban
	2025	1.96E+00	8.69E-01	1.10E+00	6.45E-57	TRUE	urban
SAIFI excluding MEDs	2020	1.20E+00	7.50E-01	4.53E-01	9.05E-23	TRUE	urban
	2021	1.32E+00	7.43E-01	5.73E-01	9.28E-36	TRUE	urban
	2022	1.15E+00	7.05E-01	4.42E-01	8.53E-26	TRUE	urban
	2023	1.13E+00	7.53E-01	3.75E-01	3.10E-18	TRUE	urban
	2024	1.11E+00	6.07E-01	4.99E-01	1.18E-29	TRUE	urban
	2025	1.18E+00	5.67E-01	6.18E-01	1.63E-41	TRUE	urban

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Comparison of Average Reliability: Low Income and High Income

- When there are statistically significant differences in the mean reliability of Low-Income and High-Income census tracts, Low-Income census tracts generally experience better average reliability.
- **Exceptions**: In 2025, High-Income census tracts experienced better average reliability in terms of:
  - CAIDI including MEDs;
  - The percentage of all-weather restorations made within 36 hours (also in 2020); and
  - The percentage of catastrophic-weather restorations made within 48 hours (also in 2020, 2024).

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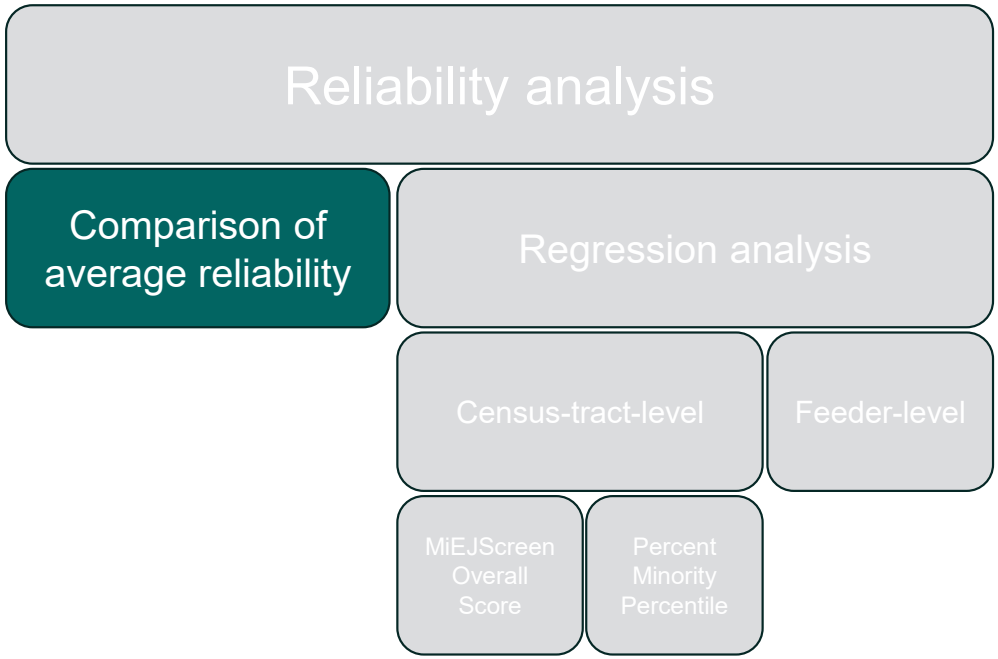
Comparison of Average Reliability: High Percent Minority Percentile and Low Percent Minority Percentile

- When there are statistically significant differences in the mean reliability of High Percent Minority Percentile and Low Percent Minority Percentile census tracts, High Percent Minority Percentile census tracts generally experience better average reliability.
- **Exceptions**: In 2025, Low-Percent-Minority-Percentile census tracts experienced better average reliability in terms of:
  - CAIDI including MEDs;
  - The percentage of all-weather restorations made within 36 hours; and
  - The percentage of catastrophic-weather restorations made within 48 hours (also in 2020).

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Comparison of Average Reliability

- Are there statistically significant differences in the average reliability of different groups of customers?
  - When there are statistically significant differences in the mean reliability of EJ and Non-EJ census tracts, EJ census tracts consistently experience better average reliability.
  - Urban, Low-Income, and High-Percent-Minority-Percentile census tracts consistently experience better average reliability than their counterparts, with a few exceptions in 2025:
    - CAIDI including MEDs;
    - The percentage of all-weather restorations made within 36 hours; and
    - The percentage of catastrophic-weather restorations made within 48 hours.



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3. Regression Analysis Results: Census Tract-Level Reliability

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Census-tract-level Reliability Regression: Overview

What correlations exist between demographic characteristics of census tracts and their reliability?

- Built regression models to relate reliability to census-tract-level demographic characteristics.
  - **Method**: Mixed-effects linear regression with county-level and year fixed effects.
  - **Data**: For each census tract
    - 18 reliability metrics (2020-2025)
    - Demographic variables based on data from MiEJScreen

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Regression Results with MiEJScreen Overall Score: SAIDI excluding MEDs

Table 9. The coefficient values (with standard errors in parentheses) of independent variables in different 2010-census-tract-level mixed-effects regression models of SAIDI excluding MEDs (with county-level and year fixed effects). All models include MiEJScreen Overall Score as a predictor. Significance codes: *** denotes p < 0.001, ** denotes p < 0.01, and * denotes p < 0.05.

Dependent variable

Predictors

	Model Number				
SAIDI excluding MEDs	1	2	3	4	5
MiEJScreen Overall Score	-1.49e+00*** (1.20e-01)	-1.60e+00*** (1.59e-01)	-1.62e+00*** (1.81e-01)	-1.12e+00*** (1.48e-01)	-1.40e+00*** (1.99e-01)
Poverty	-	1.36e-01 (1.29e-01)	-	-	2.66e-01 (1.83e-01)
Median Household Income, Past 12 Months (per $10,000)	-	-	-1.84e+00 (1.97e+00)	-	1.05e+00 (2.35e+00)
Population Density (People per Sq. Mile)	-	-	-	-7.51e-01*** (1.81e-01)	-7.88e-01*** (1.87e-01)
Percent Unemployed	-	-	-	-	3.03e+00*** (5.97e-01)
Housing Burden	-	-	-	-	-2.57e-01 (1.53e-01)

Model with most controls, and what we consider the final model. We interpret the coefficients of the predictors in this model.

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Regression Results with MiEJScreen Overall Score: SAIDI excluding MEDs

- When all other variables and factors are held constant:
  - A one percentage point increase in the **MiEJScreen Overall Score** is associated with a 1.40 minute decrease in SAIDI excluding MEDs (improving reliability);
    - 2025 Analysis: 1.36 minute decrease.
  - An increase in **Population Density** of 100 people per square mile is associated with a 0.79 minute decrease in SAIDI excluding MEDs (improving reliability);
    - 2025 Analysis: 0.9 minute decrease.
  - A one percentage point increase in **Percent Unemployed** is associated with an 3.0 minute increase in SAIDI excluding MEDs (worsening reliability);
    - 2025 Analysis: 2.91 minute increase.
- **Poverty** and **Housing Burden** are not statistically significant, though they were in the 2025 Analysis.
- **Median Household Income, Past 12 Months** is not statistically significant and wasn't in the 2025 Analysis.

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Regression Results with MiEJScreen Overall Score: SAIFI excluding MEDs

- When all other variables and factors are held constant:
  - A one percentage point increase in the **MiEJScreen Overall Score** is associated with a decrease of 0.006 interruptions per customer (improving reliability);
    - 2025 Analysis: decrease of 0.005 interruptions per customer.
  - An increase in **Population Density** of 100 people per square mile is associated with a decrease of 0.004 interruptions per customer (improving reliability);
    - 2025 Analysis: decrease of 0.004 interruptions per customer.
  - A one percentage point increase in **Percent Unemployed** is associated with an increase of 0.01 interruptions per customer (worsening reliability); and
    - 2025 Analysis: increase of 0.01 interruptions per customer.
- **Poverty** is not statistically significant, though it was in the 2025 Analysis.
- **Housing Burden** and **Median Household Income, Past 12 Months** are not statistically significant and were not in the 2025 Analysis.

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Census-tract-level Reliability Regression: Summary for MiEJScreen Overall Score

- MiEJScreen Overall Score is statistically significant and correlated with improving reliability in terms of:
  - Unique Customers with an Interruption;
  - Total Customer Interruptions;
  - SAIDI (excluding and including MEDs);
  - SAIFI (excluding and including MEDs);
  - CAIDI (excluding and including MEDs);
  - CELID-5 and -24; and
  - CEMI-4, -5, and -7.
- The correlation between MiEJScreen Overall score and reliability is not statistically significant for:
  - CEMI-10;
  - The percentage of normal-weather restorations made within 8 hours;
  - The percentage of gray-sky-weather restorations made within 24 hours;
  - The percentage of all-weather restorations made within 36 hours*; or
  - The percentage of catastrophic-weather restorations made within 48 hours.
- * In 2025 Analysis, MiEJScreen Overall score was statistically significant and correlated with improving reliability in terms of the percentage of all-weather restorations made within 36 hours.
- **These results show no evidence that census tracts with higher MiEJScreen Overall Scores tend to have worse reliability than other census tracts.**

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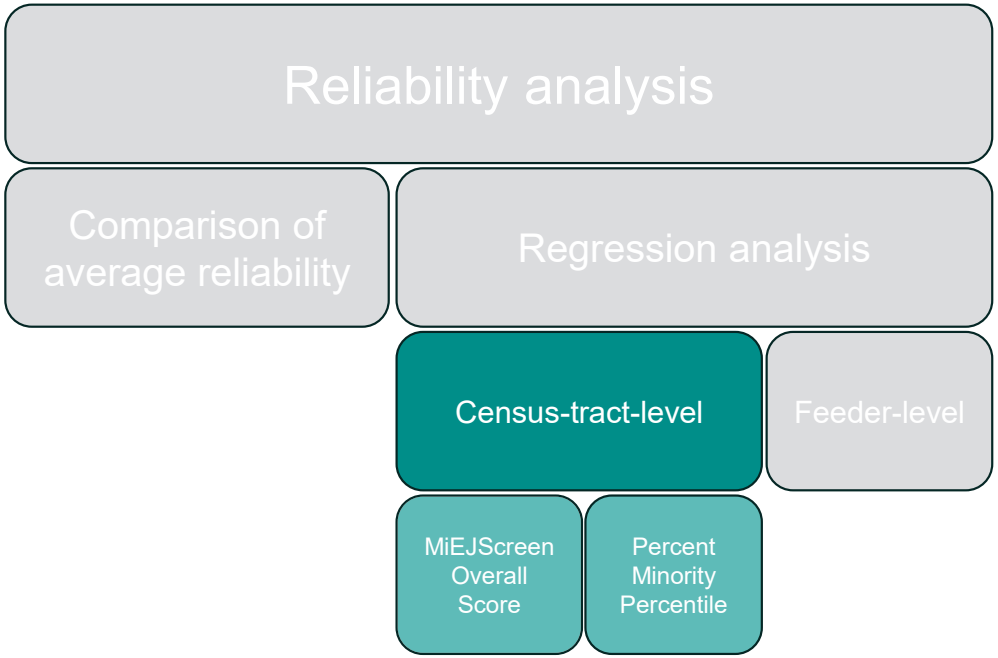
Census-tract-level Reliability Regression: Summary for Percent Minority Percentile

- Percent Minority Percentile is statistically significant and correlated with improving reliability in terms of:
  - Unique Customers with an Interruption;
  - Total Customer Interruptions;
  - SAIDI (excluding and including MEDs);
  - SAIFI (excluding and including MEDs);
  - CELID-5 and -24; and
  - CEMI-4, -5, -7, and -10.
- Percent Minority Percentile is not statistically significant for:
  - CAIDI (excluding or including MEDs);
  - The percentage of normal-weather restorations made within 8 hours;
  - The percentage of gray-sky-weather restorations made within 24 hours;
  - The percentage of all-weather restorations made within 36 hours*; or
  - The percentage of catastrophic-weather restorations made within 48 hours.
- **These results show no evidence that census tracts with higher Percent Minority Percentile values tend to have worse reliability than other census tracts.**

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Census-tract-level Reliability Regression: Summary

- What correlations exist between demographic characteristics of census tracts and their reliability?
  - Increasing MiEJScreen Overall Score tends to be associated with improving reliability, when a statistically significant correlation between the two exists.
  - Increasing Percent Minority Percentile also tends to be associated with improving reliability.
  - Census tracts with higher poverty and unemployment rates tend to have longer and more frequent outages when all other variables and factors are held constant.



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4. Regression Analysis Results: Feeder-Level Reliability

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Feeder-level Reliability Regression: Overview

What correlations exist between feeder characteristics and their reliability?

- Built regression models to relate reliability to feeder characteristics.
  - **Method**: Mixed-effects linear regression with year fixed effects.
  - **Data**: For each feeder:
    - 4 reliability metrics (2020-2025):
      - SAIDI (excluding and including MEDs)
      - SAIFI (excluding and including MEDs)
    - Physical attributes
    - Percent of its length within a 2010 census tract
    - Demographic variables based on data from MiEJScreen

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Feeder-level Reliability Regression: Feeder Characteristics

Physical characteristics of feeders that were included in the models are:

- Customers per Primary Line Mile;
- Mean Canopy Cover Percentage;
- Open Wire Secondary Miles;
- Primary Miles;
- Primary Underground Percentage;
- Voltage (categorical);
  - Reference value is 4.8/8.32 kV Wye Grounded, since it's the most common of all feeder voltages.
- Years Since Last Trim < 7 (binary).

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Feeder-level Reliability Regression: Demographic Characteristics

- We also included demographic characteristics of the areas served by each feeder as binary variables:
  - Serves an EJ census tract;
  - Serves an Urban census tract;
  - Serves a Low-Income census tract; and
  - Serves a High-Percent-Minority-Percentile census tract.
- A feeder was considered as serving a type of census tract if any part of its length overlapped with that type of census tract.

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Feeder-Level Average Reliability

- Average feeder reliability provides context for interpreting regression results.
- Consumers provided updated feeder data for 2020 through 2025.
- Feeder reliability in 2025 was worse, on average, than in 2024.

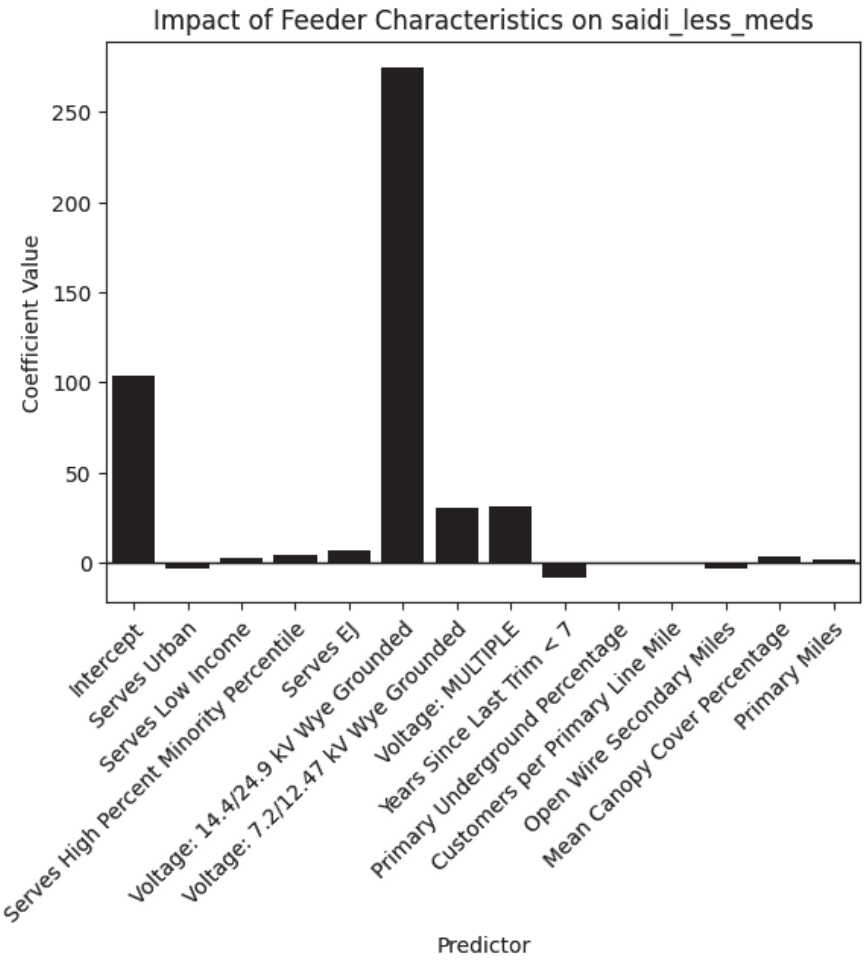
Table 4. The average value (over all feeders in Consumers' distribution system) of each of four feeder-level reliability metrics in each year from 2020 through 2025.

Reliability Metric	2020	2021	2022	2023	2024	2025
SAIDI excluding MEDs	193.65	235.95	184.18	195.9	183.69	196.32
SAIDI including MEDs	535.83	970.7	467.62	1074.43	589.62	957.13
SAIFI excluding MEDs	1.01	1.08	0.94	1.02	1.01	1.05
SAIFI including MEDs	1.33	1.62	1.23	1.47	1.5	1.65

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Feeder-level Regression Results: SAIDI excluding MEDs

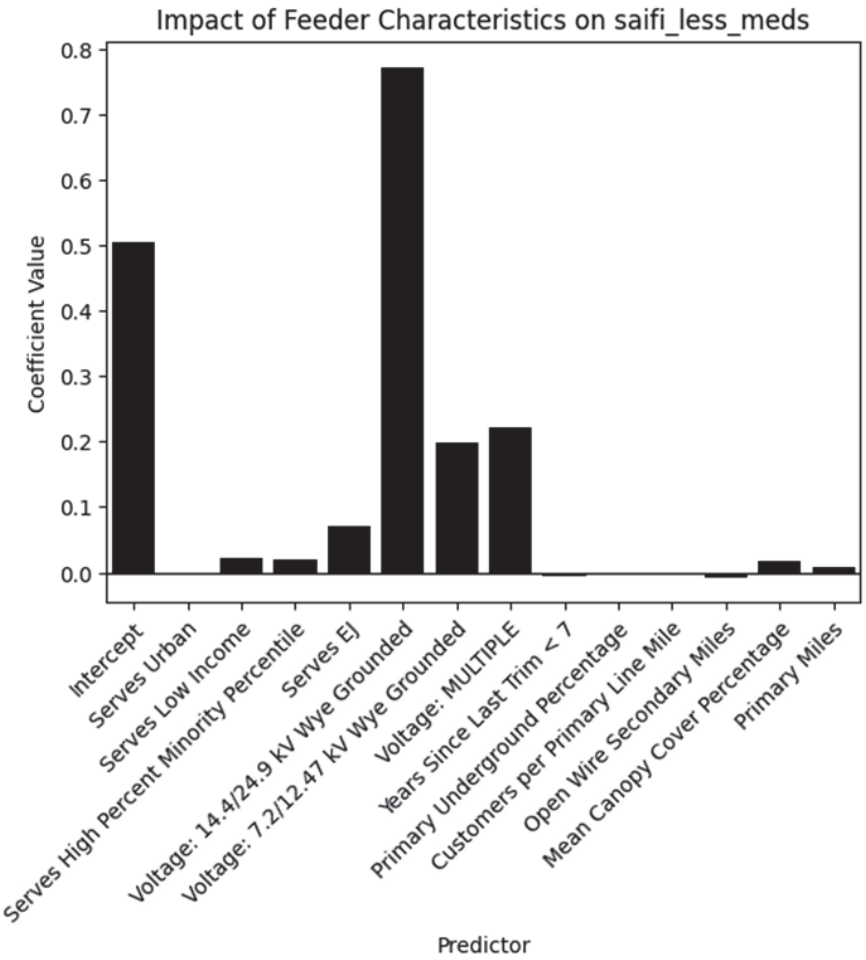
- Voltage can have a large and statistically significant correlation with SAIDI excluding MEDs. When all other variables are held constant and relative to the reference voltage:
  - 14.4/24.9 kV Wye Grounded (+275 minutes)
  - 7.2/12.47 kV Wye Grounded (+31 minutes)
  - MULTIPLE (+31 minutes)
- Feeder characteristics with statistically significant correlations with SAIDI excluding MEDs are:
  - **Primary Underground Percentage**: A one percentage-point increase is associated with a 0.9 minute decrease (improving reliability).
  - **Customers per Primary Line Mile**: An increase of 1 customer per primary line mile is associated with a 0.5 minute decrease (improving reliability).
  - **Mean Canopy Cover Percentage**: A one percentage-point increase is associated with 3.9 minute increase (worsening reliability).
  - **Primary Miles**: Every one-mile increase is associated with a 1.7 minute increase (worsening reliability).
- Open-Wire Secondary Miles is not statistically significant but was in 2025 Analysis.
- None of the demographic characteristics has a statistically significant correlation with SAIDI excluding MEDs.



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Feeder-level Regression Results: SAIFI excluding MEDs

- Voltage can have a large and statistically significant correlation with SAIFI excluding MEDs. When all other variables are held constant and relative to the reference voltage:
  - 7.2/12.48 kV Wye Grounded (+0.2 interruptions/customer/year)
  - 14.4/24.9 kV Wye Grounded (+0.8 interruptions/customer/year)
  - MULTIPLE (+0.2 interruptions/customer/year)
- All other feeder characteristics (except Open Wire Secondary Miles) have statistically significant correlations with SAIFI excluding MEDs.
  - **Primary Underground Percentage**: A one percentage-point increase is associated with a decrease of 0.004 interruptions/customer/year (improving reliability).
  - **Customers per Primary Line Mile**: An increase of 1 customer per primary line mile is associated with a decrease of 0.002 interruptions/customer/year (improving reliability).
  - **Mean Canopy Cover Percentage**: A one percentage-point increase is associated with an increase of 0.02 interruptions/customer/year (worsening reliability).
  - **Primary Miles**: Every one-mile increase is associated with an increase of 0.009 interruptions/customer/year (worsening reliability).
- None of the demographic characteristics included has a statistically significant correlation with SAIFI excluding MEDs.

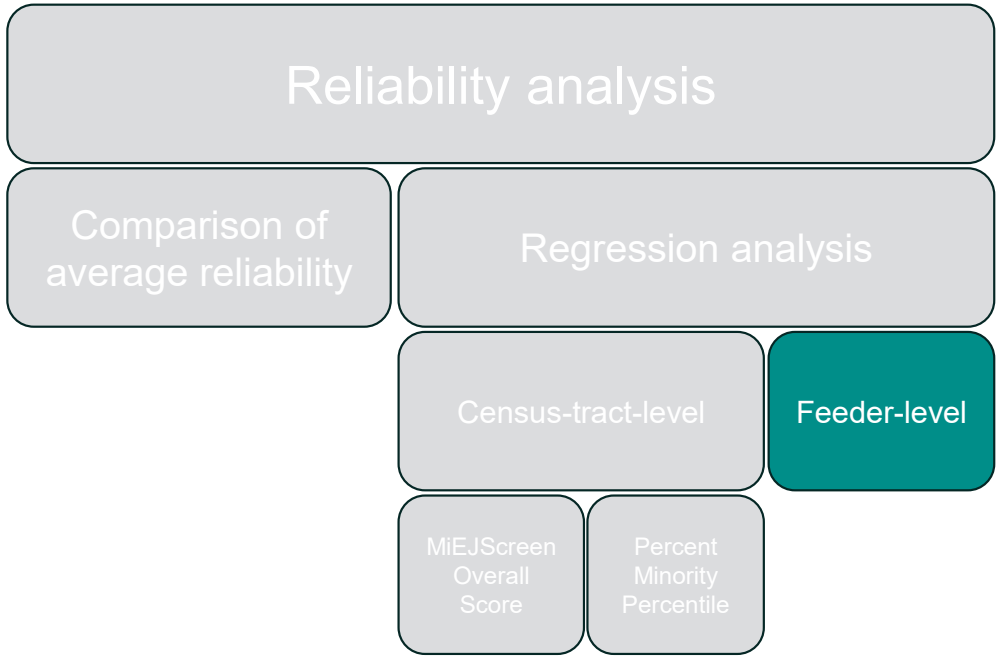


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Feeder-level Reliability Regression: Summary

What correlations exist between feeder characteristics and their reliability?

- None of the demographic characteristics (Serves Urban, EJ, Low-Income, or High-Percent-Minority-Percentile) included in the feeder regression analysis had statistically significant correlations with feeder reliability.
  - In 2025 Analysis, feeders that serve Urban census tracts tended to have shorter outage durations than feeders that don't serve Urban census tracts.
  - In 2025 Analysis, feeders that serve EJ census tracts tended to have more frequent outages than feeders that don't serve EJ census tracts.
- Physical characteristics of feeders have statistically significant correlations with their reliability.



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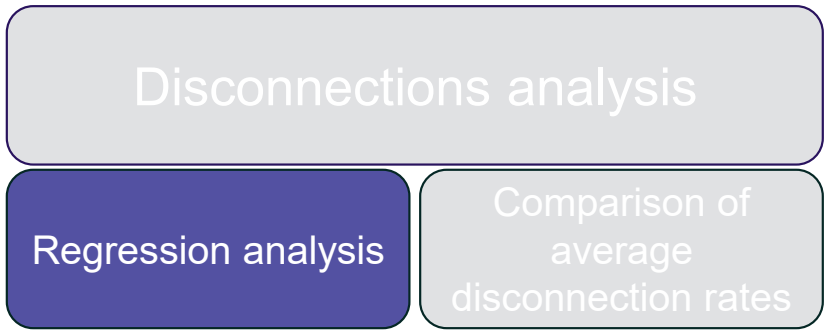
5. Regression Analysis Results: Disconnection Rates

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Disconnections Regression Analysis: Overview

What correlations exist between demographic characteristics and disconnection rates?

- Built regression models to relate reliability to census-tract-level demographic characteristics.
  - **Data**: For each 2020 Census tract in Consumers' service territory:
    - Count of disconnections in each year (2021*-2024)
    - Demographic variables based on data from the American Community Survey (ACS) – 5-year estimates (2021-2024**)
    - New ➡ Energy burden data from DoE LEAD Tool (do not vary with time)



* Disconnection data for 2020 were excluded given the voluntary moratorium instituted by Consumers in response to the COVID-19 pandemic for the better part of that year.

** ACS 5-year estimates for 2025 were not available at the time of this analysis.

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Disconnections: Descriptive Statistics

Table 17. Descriptive statistics (i.e., mean, standard deviation, minimum, and maximum) of disconnection rates (in units of disconnections per 1000 households) among 2020 Census tracts in Consumers' service territory from 2020 through 2024.

Year	Mean	Standard Deviation	Minimum	Median	95th Percentile	Maximum	No. of Census Tracts
2020	14.90	11.56	0.40	12.15	36.88	80.62	1133
2021	53.67	52.24	0.43	39.45	175.54	363.64	1152
2022	51.56	50.16	0.37	37.31	168.46	400.00	1151
2023	58.08	54.76	0.43	43.82	176.50	435.09	1147
2024	64.68	60.65	0.41	48.46	195.76	833.33	1150

- In 2024, the maximum disconnection rate occurred in a census tract in Isabella County that is comprised mostly of Central Michigan University's campus.
  - It had 15 disconnections and 18 households in 2024, resulting in a disconnection rate of 833.33 per 1000 households.

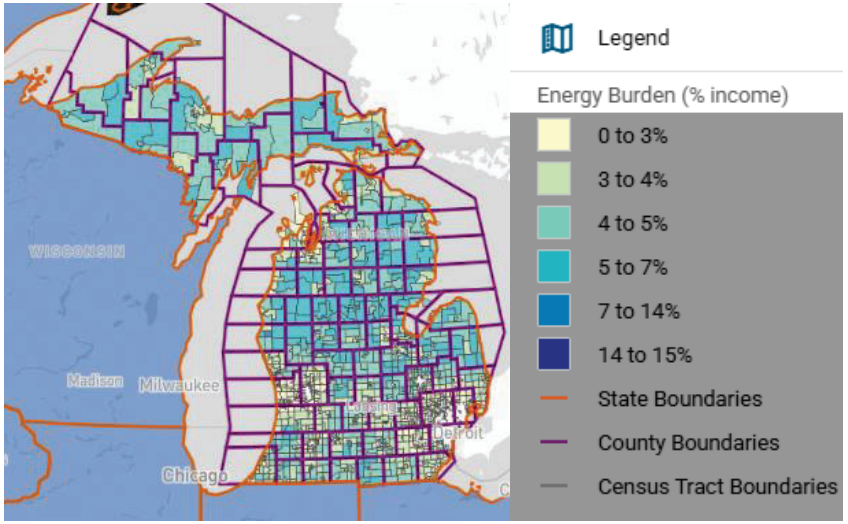
On-campus housing – **not included** in household count



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Disconnections Regression: Including Energy Burden

- The Department of Energy's LEAD tool provides census tract-level data on Electric Energy Burden (% income).
- LEAD data are provided once, i.e., do not vary by year.
- Memmott et al. (2024) find that energy cost is significant (at the p < 0.01 level) in their their zip-code-level regression model for disconnection rate in California.



Source: US Department of Energy Low-income Energy Affordability Data Tool.

Memmott, T., Konisky, D.M., and Carley, S. (2024). *Assessing demographic vulnerability and weather impacts on utility disconnections in California*. Nature Communications, Vol. 15:9458. https://doi.org/10.1038/s41467-024-53913-y

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Disconnections Regression Analysis: Results

Disconnection Rates (2021-2024)
4553 observations

Table 20. Panel regression model for disconnection rate (in units of disconnections per 1000 households) considering year- and county-level fixed effects: coefficients for each independent variable, standard errors, and p-values. * indicates $p < 0.05$.

Variable	Coefficient	Standard Error	p-value
Intercept	39.55*	12.48	1.54E-03
Percentage Minority Population	1.14*	0.15	3.60E-14
Percentage Below Poverty	0.52*	0.20	1.08E-02
Percentage Renters	0.18*	0.06	4.17E-03
Unemployment Rate	0.28	0.43	5.12E-01
Percentage of Homes Built after 1990	-0.22*	0.07	3.13E-03
Population Density	-5.94*	2.28	9.37E-03
Median Home Value (per $10,000)	-1.16*	0.34	7.48E-04
Energy Burden (% Income), Electricity	6.86*	3.36	4.13E-02

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Disconnections Regression Analysis: Results

When all other variables, as well as county-level and year factors, are held constant:

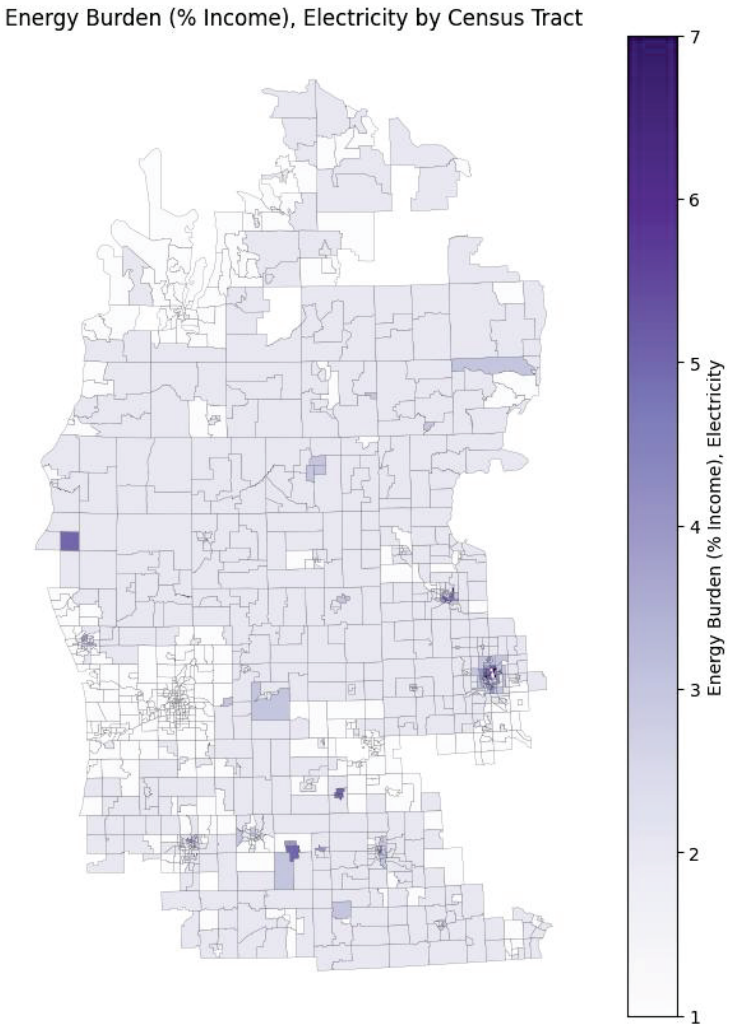
- **Percentage Minority Population**: A one percentage-point increase in minority population is associated with an increase of 1.14 disconnections per 1000 households.
- **Percentage Below Poverty Population**: A one percentage-point increase in below poverty population is associated with an increase of 0.52 disconnections per 1000 households.
- **Percentage Renters**: A one percentage-point increase in the percentage of renters is associated with an increase of 0.18 per 1000 households.
- **Percentage of Homes Built after 1990**: A one percentage-point increase in percentage of homes built after 1990 is associated with a decrease of 0.22 disconnections per 1000 households.
- **Population Density**: An increase of 1000 households per square mile is associated with a decrease of 5.94 disconnections per 1000 households.
- **Median Home Value**: A $10,000 increase in a census tract's Median Home Value is associated with a decrease of 1.16 disconnections per 1000 households.

New ➡
- **Energy Burden (% Income), Electricity**: A one percentage-point increase in energy burden is associated with an increase of 6.86 disconnections per 1000 households.

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Disconnections Regression Analysis: Discussion

- Energy burden has the largest correlation with disconnection rate, as expected.
- The statistically significant positive correlation between Percentage Minority Population and disconnection rate that was observed in 2025 Analysis persists even when energy burden is controlled for.
  - The magnitude of the correlation between Percentage Minority Population and disconnection rate is smaller than that between Energy Burden and disconnection rate.
- The results of the current analysis are consistent with those of the 2025 Analysis.

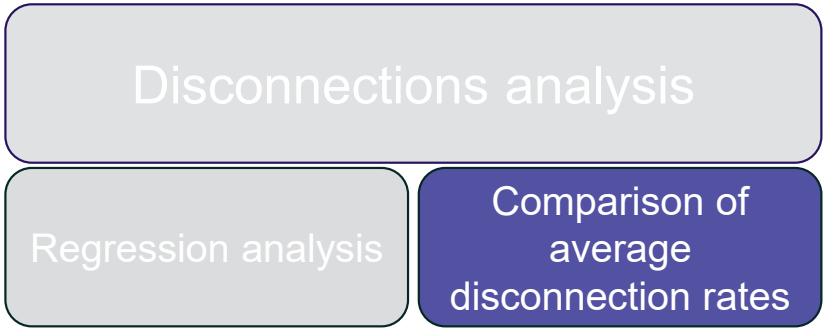


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Disconnections & Reliability Analysis: Overview

Do communities with the worst reliability also have higher disconnection rates than other communities?

- Assessed whether statistically significant differences exist in the average disconnection rates of (1) the 10% of census tracts with the worst reliability (as measured by 18 different metrics); and (2) all other census tracts.
  - **Methods**: Binary difference-in-means t-test.
  - **Data**: For each 2020 census tract in Consumers' service territory:
    - Count of disconnections in each year (2020-2024) → disconnection rate
    - 18 reliability metrics in each year (2020-2024)



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Comparison of Average Reliability: Census Tracts with Highest Disconnection Rates and Other Census Tracts

- This analysis shows no evidence that census tracts with the worst reliability consistently experience statistically significant, higher disconnection rates than other census tracts.
- Current results are consistent with observations in 2025 Analysis.

Excerpt of Table 21.

Reliability Metric	Year	Non-Vulnerable Mean	Vulnerable Mean	Difference	p-value	Significant?	Worse?
Unique Customers with an Interruption	2020	1.52E+01	1.23E+01	2.89E+00	6.35E-05	TRUE	Non-vulnerable
	2021	5.52E+01	4.14E+01	1.39E+01	1.45E-08	TRUE	Non-vulnerable
	2022	5.28E+01	4.14E+01	1.14E+01	8.55E-06	TRUE	Non-vulnerable
	2023	5.98E+01	4.53E+01	1.44E+01	1.67E-06	TRUE	Non-vulnerable
	2024	6.64E+01	5.19E+01	1.45E+01	1.19E-05	TRUE	Non-vulnerable
Total Customer Interruptions	2020	1.49E+01	1.48E+01	1.30E-01	8.87E-01	FALSE	N/A
	2021	5.55E+01	3.93E+01	1.62E+01	1.05E-09	TRUE	Non-vulnerable
	2022	5.31E+01	3.88E+01	1.43E+01	3.38E-08	TRUE	Non-vulnerable
	2023	6.02E+01	4.17E+01	1.84E+01	9.36E-10	TRUE	Non-vulnerable
	2024	6.66E+01	5.10E+01	1.56E+01	1.69E-07	TRUE	Non-vulnerable
SAIDI including MEDs	2020	1.50E+01	1.38E+01	1.20E+00	2.22E-01	FALSE	N/A
	2021	5.58E+01	3.53E+01	2.05E+01	1.23E-12	TRUE	Non-vulnerable
	2022	5.29E+01	4.08E+01	1.21E+01	3.37E-04	TRUE	Non-vulnerable
	2023	6.01E+01	4.23E+01	1.77E+01	2.21E-07	TRUE	Non-vulnerable
	2024	6.61E+01	5.45E+01	1.17E+01	7.74E-03	TRUE	Non-vulnerable
SAIDI excluding MEDs	2020	1.52E+01	1.20E+01	3.21E+00	8.49E-05	TRUE	Non-vulnerable
	2021	5.57E+01	3.63E+01	1.93E+01	5.20E-09	TRUE	Non-vulnerable
	2022	5.32E+01	3.77E+01	1.55E+01	5.00E-04	TRUE	Non-vulnerable
	2023	5.98E+01	4.47E+01	1.51E+01	1.56E-03	TRUE	Non-vulnerable
	2024	6.67E+01	4.84E+01	1.83E+01	1.25E-04	TRUE	Non-vulnerable
SAIFI including MEDs	2020	1.51E+01	1.30E+01	2.19E+00	2.61E-02	TRUE	Non-vulnerable
	2021	5.56E+01	3.74E+01	1.82E+01	1.20E-06	TRUE	Non-vulnerable
	2022	5.30E+01	3.93E+01	1.37E+01	6.64E-04	TRUE	Non-vulnerable
	2023	6.02E+01	4.12E+01	1.89E+01	1.52E-05	TRUE	Non-vulnerable
	2024	6.66E+01	4.95E+01	1.71E+01	1.80E-04	TRUE	Non-vulnerable
SAIFI excluding MEDs	2020	1.49E+01	1.56E+01	-7.25E-01	5.80E-01	FALSE	N/A
	2021	5.57E+01	3.60E+01	1.97E+01	1.80E-07	TRUE	Non-vulnerable
	2022	5.30E+01	3.93E+01	1.37E+01	1.68E-03	TRUE	Non-vulnerable
	2023	5.93E+01	4.89E+01	1.05E+01	4.42E-02	TRUE	Non-vulnerable
	2024	6.68E+01	4.86E+01	1.82E+01	1.05E-04	TRUE	Non-vulnerable

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6. Key Takeaways & Next Steps

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Key Takeaways

- Census-tract-level Reliability
  - Increasing MiEJScreen Overall Score and increasing Percent Minority Percentile are often associated with improving reliability when all other variables and factors are held constant.
- Feeder-level Reliability
  - Whether a feeder serves an EJ census tract does not have a statistically significant correlation with its reliability.
  - Whether a feeder serves different demographic groups (Urban, Low-Income, High-Percent-Minority-Percentile) does not have a statistically significant correlation with its reliability.
- Disconnections
  - When all other variables and factors are held constant, increasing Energy Burden (% Income), Electricity in a census tract is statistically significant and associated with increasing disconnection rate.
  - Energy burden has the greatest correlation with disconnection rate among all predictors included in the model.
  - The statistically significant positive correlation between Percentage Minority Population and disconnection rate that was observed in the 2025 Analysis persists even when energy burden is controlled for but is smaller than the correlation between energy burden and disconnection rate.

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Next Steps

- **Refresh dashboard**: update interactive format to inspect data and results.

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Limitations

The study presented in the report and summarized in these slides is intended for use by Consumers Energy Company ("Consumers") to inform their decisions related to distributional equity of electric reliability among the various communities that they serve. While this study is informative, it is understood and agreed that responsibility for these decisions remain fully with Consumers. Proper application of this report requires recognition and understanding of the limitations of both the scope and methodology of the study. The scope of the study was limited to performing regression analysis to assess correlations between electric reliability and: (1) demographic characteristics of communities served by Consumers; and (2) physical characteristics of distribution circuits. The scope of the study also included regression analysis of correlations between residential involuntary disconnections for non-payment and demographic characteristics of communities within Consumers' service territory.

In the analysis, Exponent has relied on data and various other information provided by Consumers. We cannot verify the correctness of this input data and rely on Consumers for their accuracy.

Exponent has exercised professional skill and care ordinarily provided by professionals practicing in the same or similar locality under the same or similar circumstances in the preparation of this report, and the findings presented herein are made based on information available to Exponent as of the date of this report. This report may be supplemented to expand or modify our findings based on additional analysis or review of additional information.

It is noted that the Executive Summary cannot summarize all of Exponent's technical evaluation, analysis, conclusions, and recommendations. Hence, the main part of the report is at all times the controlling document.

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Mitigating Wildfire Risk in Consumers Energy's Service Territory (2026-2030)

June 2026

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Executive Summary

Consumers Energy has proudly served Michigan families and businesses since 1886, with more than 1.9 million electric customers across the state today. The Company is committed to providing an electric distribution system that delivers safe, reliable, clean, and affordable electricity to customers today and in the future. To do that, Consumers Energy must address the wildfire risk brought on by changing climate in Michigan[1].

Over the last decade, wildfires have grown in number and severity throughout the United States and become a significant public health and safety concern. In the last 10 years, Michigan's lower peninsula has averaged approximately 200 wildfires per year, burning an average of nearly 2,000 acres each year.[2] Given these trends, the Company developed this plan to mitigate destructive wildfire risk in Consumers Energy's electric territory.

Consumers Energy is guided by its ambition to deliver world class performance delivering hometown service, measured by our triple bottom line of people, planet, and Michigan's prosperity. Our triple bottom line considers the interests of customers and other stakeholders and captures the broader societal impacts of the Company's activities.

Purpose

This plan describes the Company's approach to mitigating the risk of wildfires caused by or impacting electrical infrastructure and surrounding communities throughout Consumers Energy's service territory, with safety as the top priority. The Company first identified the growing risk of wildfires as a result of changing weather patterns in the Reliability Roadmap published in September 2023[3] and subsequently created this plan to mitigate that risk.

This document outlines the plans and actions Consumers Energy is taking to develop competencies, invest in system hardening, and expand existing programs such as line clearing to alleviate the pressure from increased wildfire risk.

The goal is the overall safety of the customers and communities we serve, and the Consumers Energy employees who serve them. This plan will continue to evolve as the Company learns more about wildfire risk in Michigan, new wildfire risk reduction strategies and technologies, and how changing weather patterns impact the region.

Objectives

Consumers Energy is driven to be an excellent corporate citizen for the state of Michigan and that means not only providing safe, reliable electricity to our 1.9 million customers but also actively making the communities we serve safer.

Our objective is to improve our distribution system to provide reliable energy delivery to our customers while hardening and protecting it against wildfire ignition risks. This will be accomplished by expanding current and investing in new programs and competencies to mitigate

[1] Wildfire Weather: Analyzing the 50-year shift across America, May 2023 - www.climatecentral.com
[2] Michigan Department of Natural Resources - Fire Report Dashboard
[3] MPSC Case No.: U-20147

risk. To do this Consumers Energy is:

- Furthering the Company's understanding of the current and probable wildfire risk areas in our service territory through development and maturity of assessment tools.
- Implementing mitigation solutions that balance the risk of wildfires with safe and reliable energy delivery.
- Leveraging existing programs, such as line clearing, to deliver benefits beyond reliability and resiliency.
- Implementing procedures to inform customers and communities of wildfire preparedness measures and communication protocols in the event of a wildfire risk event, i.e., *Red Flag Warnings*.
- Engaging customers and communities in the ongoing development of the wildfire risk mitigation plan, particularly as it relates to ensuring customer safety and electric reliability.
- Continuously improving this plan by leveraging industry experts and peers and learning about and deploying best practices.

Wildfire Risk Mitigation Activities

To meet Consumers Energy's wildfire risk mitigation plan objectives, the Company is focused on the following:

- **Situational Awareness:** Monitor weather, any heightened wildfire risk warnings (including *Red Flag Warnings*), and conditions on the Low Voltage Distribution ("LVD") system to respond to wildfire risks.
- **Operational Procedures:**
    - *Field Operations:* Use modified field operating procedures to reduce the risk of ignition from utility infrastructure or operations, and to ensure the safety of our employees.
    - *Recloser Settings:* Employ procedures to mitigate spark risk on the distribution system during elevated wildfire risk periods.
    - *Public Safety Power Shutoff:* Maintain a plan to de-energize specific areas of the distribution network during extreme wildfire risk periods to pre-emptively eliminate potential spark risk from Consumers Energy's distribution system.
    - *Emergency Preparedness:* Maintain a wildfire-specific emergency action plan to enable Emergency Management to act quickly in case of wildfire danger.
- **System Hardening:**
    - *Protective Line Devices:* Install non-expulsion fuses to limit spark when a fuse opens as well as remotely controlled line reclosers or other devices to increase sectionalization and control of LVD lines in the elevated wildfire risk areas.
    - *Covered Conductor:* Install covered conductor and other LVD construction methods in elevated risk areas to reduce chance of spark or arcing, which would result in a potential

ignition due to contact with another conductor, animal, vegetation or any other material.

- *Undergrounding:* Convert portions of the overhead distribution system to underground using specific criteria designed to identify line segments with the highest potential to eliminate wildfire risk associated with overhead conductor.

- **Line Clearing:** Leverage the newly implemented 5-year clearing cycle for the LVD system with a more aggressive timeline to achieve this cycle in elevated wildfire risk areas better to manage growth and limit potential vegetation-to-conductor contact. Capture Light Detection and Ranging ("LiDAR") imagery to inform and support line clearing tactics.

Figures 1 and 2 summarize the estimated costs for Consumers Energy's proposed wildfire risk mitigation activities over the next five years. This plan grows to over $6 million in capital and $600 thousand in O&M as the Company builds its capabilities to mitigate wildfire risk.

Given the Commission order in Case No. U-21585 requiring a more detailed benefit-cost analysis to substantiate capital investment in mitigating wildfire risk, the Company worked with a third party to provide greater detail as to the value of Wildfire Risk Mitigation investments. The third-party wildfire risk assessment including the benefit-cost analysis is explained further in the Wildfire Risk Assessment section below. The capital plan resulting from this analysis is summarized in Figure 1 below.

Figure 1

Consumers Energy's Wildfire Risk Mitigation Capital Investment Plan

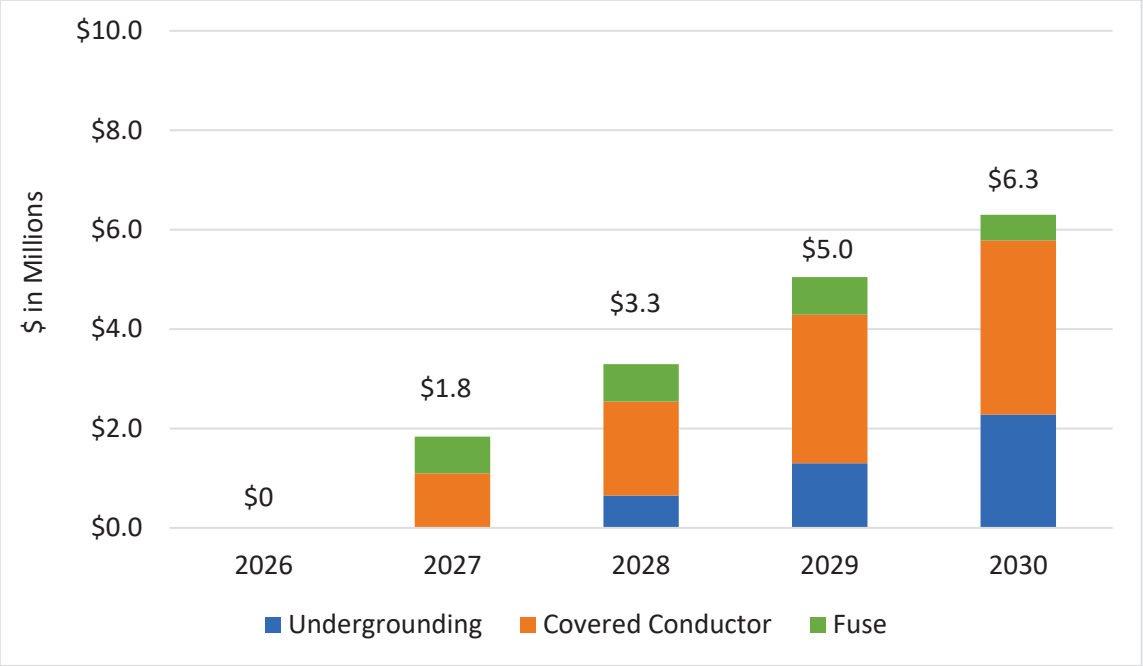
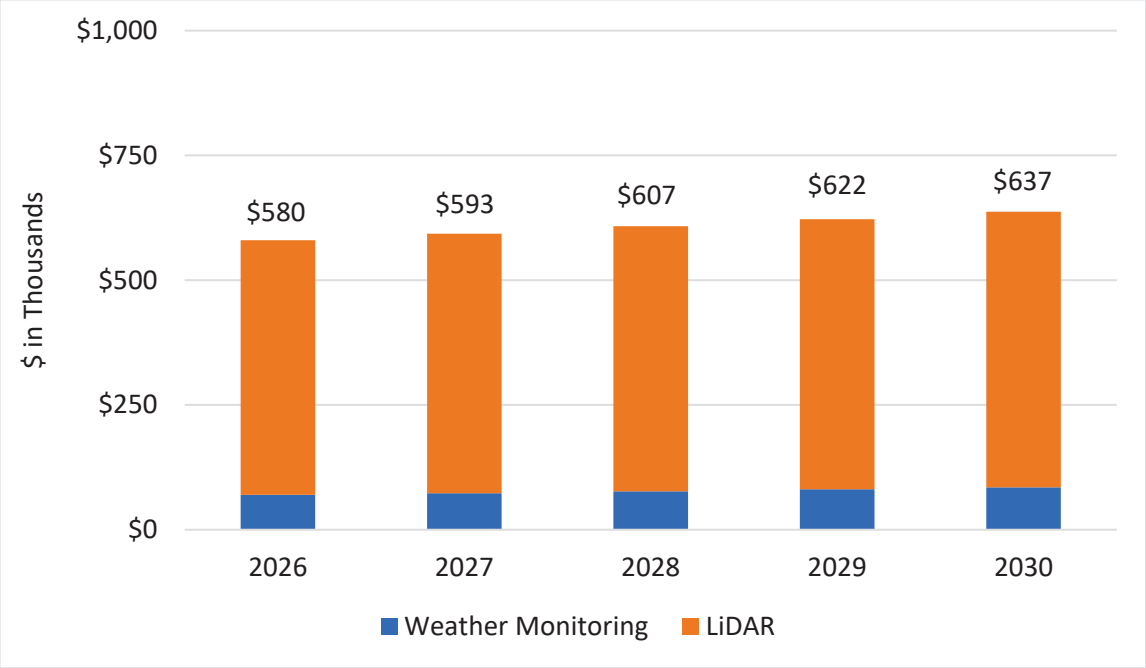


Figure 2

Consumers Energy's Wildfire Risk Mitigation O&M Plan



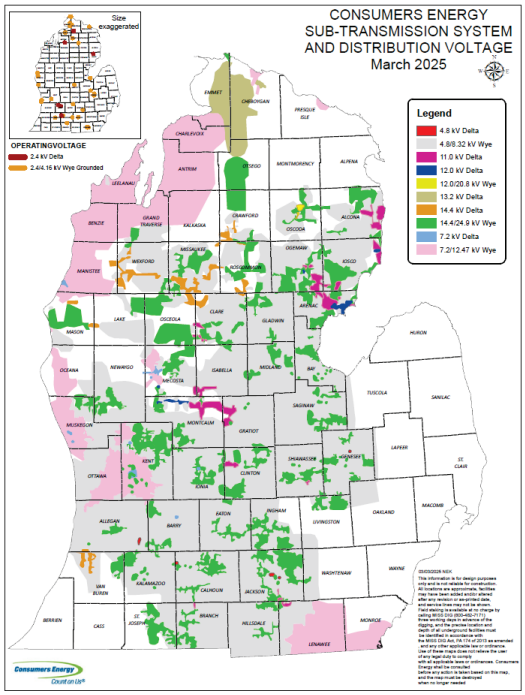
Risk Assessment and Mapping

Consumers Energy Service Territory Overview

The Company's electric distribution system is an essential part of Michigan's infrastructure, serving 1.9 million customers across more than 114,000 miles of distribution lines and approximately 1,140 substations in the Lower Peninsula of Michigan, from Monroe County to Mackinaw City, as shown in Figure 3.

Figure 3

Consumers Energy's Electric Service Territory



The distribution system is functionally separated by operating voltage into High Voltage Distribution ("HVD") and LVD.

- HVD operates at the highest voltages, taking electricity from regional transmission companies, and transporting it across miles of lines, where it connects into the LVD system at substations throughout the Company's service territory.
- At LVD substations, high voltage is 'stepped down' (or reduced to lower voltages) onto the LVD system. LVD voltage is then further stepped down at secondary distribution transformers to secondary voltages (120 to 480 Volts), serving businesses and residences.

The LVD system is comprised of more than 114,000 total miles of lines, made up of approximately 64,000 miles of primary overhead and underground (carries electricity from substations to transformers), and 50,0000 miles of secondary (carries electricity from distribution transformers to customers).

The HVD system is comprised of approximately 4,900 total miles, consisting almost entirely of 46 kV lines and including radial 138 kV and 69 kV lines.

Wildfire History within Consumers Energy's Service Territory

Consumers Energy has used historical wildfire information from 2016 through 2025 from the Michigan Department of Natural Resources ("DNR") combined with the Federal Emergency Management Agency ("FEMA") *National Risk Index* map, and risk analysis performed by a third-party to continue growing our knowledge and understanding of wildfire risk in Consumers Energy's service territory.

Historically, wildfires have occurred throughout the lower peninsula. For instance, the Thumb Fire, also known as The Great Fire of 1881, burned more than 1 million acres in less than a day, with nearly 300 people[4] losing their lives. It also destroyed more than 1,500 dwellings and stranded over 14,000 people[5].

Over the last 10 years, nearly 2,000 wildfires in the lower peninsula burned almost 20,000 acres. Five of the last ten years have seen more than 2,000 acres burned each year.[6]

Several wildfires in recent history have burned multiple thousands of acres, and significantly impacted the northern lower peninsula:

- 2023 Wilderness Trail Fire – Burned approximately 2,400 acres, closed I-75, necessitated flight restrictions below 5,000 feet; was caused by a campfire, and required Consumers Energy to de-energize a 46kV line, interrupting service to almost 3,000 customers.
- 2022 Blue Lakes Fire – Burned 2,500 acres, closed multiple roads in the area, and was caused by a lightning strike.
- 2010 Meridian Boundary Fire – Burned more than 8,800 acres and 51 structures, closed multiple roads in the area, and was caused by burning debris.

To understand the timing of historical wildfires in the lower peninsula of Michigan, Consumers Energy evaluated the average number of wildfires by month and number of days *Red Flag Warnings* were issued by the National Weather Service. The National Weather Service declares *Red Flag Warnings* when there are "warm temperatures, very low humidities, and stronger winds which are expected to combine to produce an increased risk of fire danger"[7]. Contributing Red Flag Factors include:

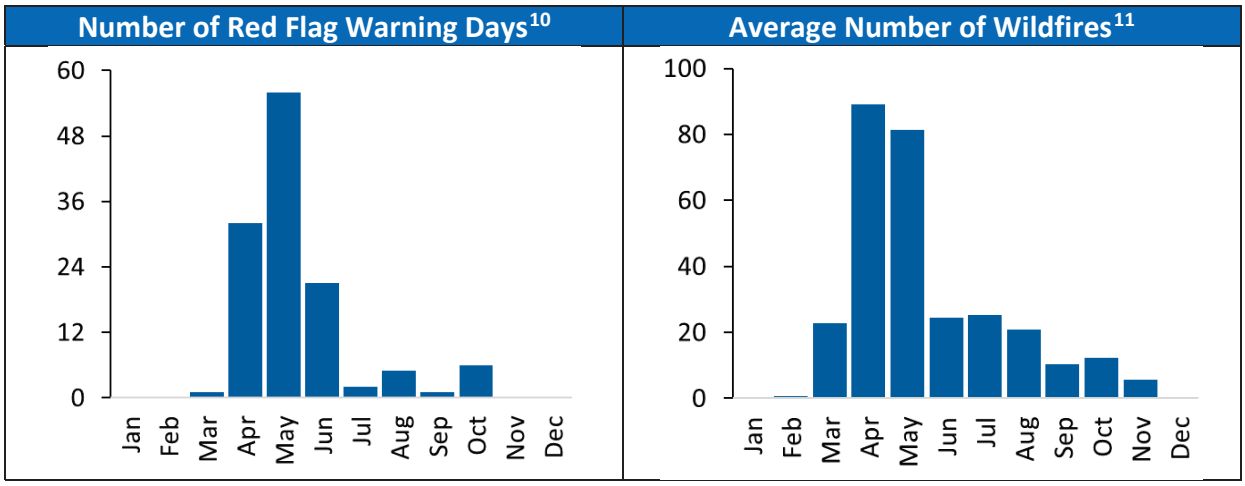
- First significant lightning occurrence after a hot and dry period.
- Significant cold frontal passage, expected to cause strong sustained and gusty winds, and an abrupt wind shift.
- Any combination of weather and fuel conditions that would create a critical fire control situation or extensive wildfire outbreak.[8]

As shown in Figure 4, the number of days with *Red Flag Warnings* issued is highest April through June and corresponds with the average number of wildfires by month being highest in March through August. Based on historic wildfire data, a wildfire is more likely to occur in the spring when underbrush and trees are dry and not yet green, and in the late summer when it becomes drier throughout the state. Given continued climate change, the drying trend will continue to worsen.[9]

[4] Deadliest Wildfires in U.S. History | WFCA
[5] Fires ravaged Michigan's thumb in 1871, 1881 | University of Michigan News (umich.edu)
[6] Michigan Department of Natural Resources - Fire Report Dashboard
[7] Red Flag Warning (weather.gov)
[8] National Weather Service Red Flag Program (Fire Weather Criteria)
[9] Fifth National Climate Assessment Ch. 4 Water

Figure 4

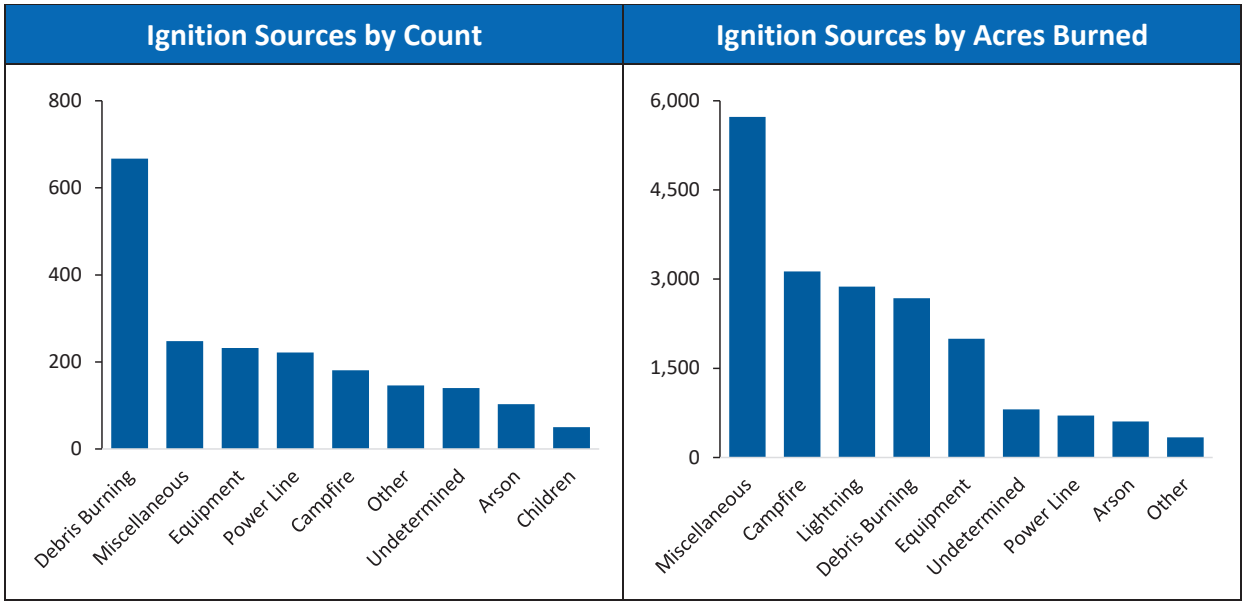
Red Flag Warnings and Wildfires in Michigan (2006-2025)



Over the last 10 years, debris burning has been the number one cause of wildfires in the lower peninsula of Michigan with miscellaneous, equipment, power lines and campfires rounding out the top five causes as shown in Figure 5. Based on the data from the Michigan DNR, power lines have caused approximately 11% of all wildfires over the last 10 years.

Figure 5

Wildfire Ignition Sources in Michigan's Lower Peninsula (2016-2025) [12]



The map in Figure 6 below shows where wildfires occurred throughout Michigan's lower peninsula in 2024. The majority of these wildfires took place in the northern part of the LP.

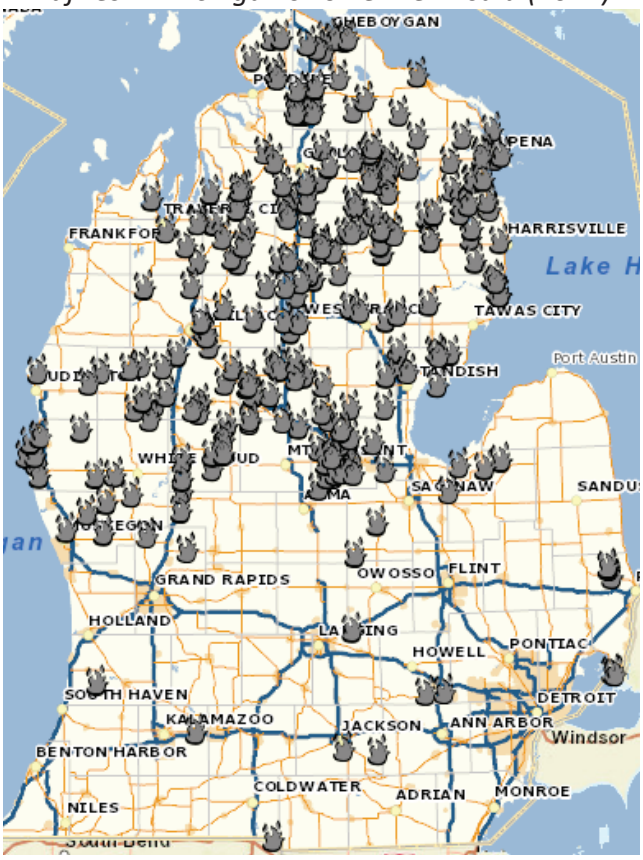
[10] Iowa Environmental Mesonet of Iowa State University - https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml

[11] Michigan Department of Natural Resources Fire Report Dashboard

[12] Michigan Department of Natural Resources Fire Report Dashboard

Figure 6

Wildfires in Michigan's Lower Peninsula (2024)[13]



It is also important to understand Michigan's fire regime and what it means for Michigan's wildfire risk profile.

A *fire regime* refers to the pattern, frequency, and intensity of wildfires in a specific area over long periods of time. In the Lower Peninsula of Michigan, fire regime group V is most common with significant portions of the area classified as fire regime groups I or III as shown in Figure 7 below. The fire regime group considers the fire return interval and the percentage of different severity fires. This classification is based on the history of fires in a particular area, as well as the fuel load and type. Less frequent fires, as seen in fire regime group V areas, increase the risk of more intense, damaging fires.

In areas of Michigan that are largely unforested or consist mainly of hardwoods, such as oak and maple with minimal shrubbery, the frequency and intensity of fires tend to remain low. Conversely, in regions dominated by softwoods, such as the Jack Pine forests of north-central Michigan, the frequency and intensity of fires are higher.

Understanding the history of fires allows for better fire management. Not all fires are bad. For instance, in Northern Michigan, Jack Pine forests rely on the heat from a fire to open and release seeds. This is one reason why the Michigan DNR and the United States Forest Service ("USFS")

[13] Department of Natural Resources (DNR Wildland Fire map)

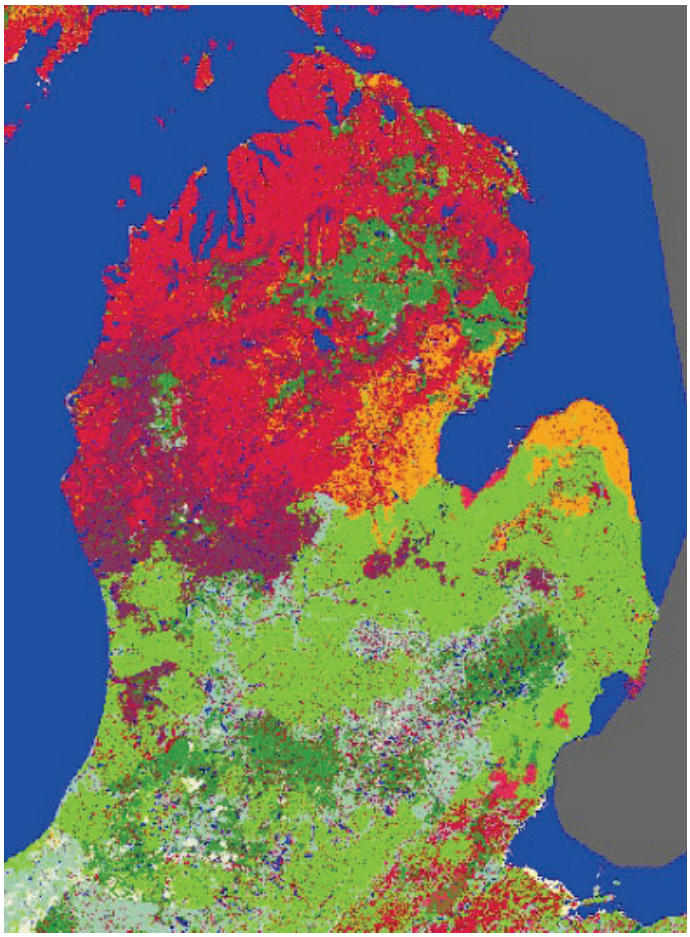
will conduct prescribed burns.

Looking at the map below in Figure 7, we can understand the different regime boundaries throughout the state based on the history of fires and can focus more resources on prevention in the higher regime areas that are more likely to be impacted by large, intense fires.

In the last 25 years, fires have impacted northern Lower Michigan including the 4 Mile Road fire (2008, 1,000 acres), Meridian Boundary Fire (2010, 8,586 acres), The Wilderness Trail Fire (2023, 2,442 acres), and Blue Lakes Fire (2022, 2,516 acres).

Figure 7

Fire Regime Groups for Michigan's Lower Peninsula[14]



Fire regime group label	Definition
I–A	Percentage of replacement fire less than 66.7%, fire return interval 0–5 years
I–B	Percentage of replacement fire less than 66.7%, fire return interval 6–15 years
I–C	Percentage of replacement fire less than 66.7%, fire return interval 16–35 years
II–A	Percentage of replacement fire greater than 66.7%, fire return interval 0–5 years
II–B	Percentage of replacement fire greater than 66.7%, fire return interval 6–15 years
II–C	Percentage of replacement fire greater than 66.7%, fire return interval 16–35 years
III–A	Percentage of replacement fire less than 80%, fire return interval 36–100 years
III–B	Percentage of replacement fire less than 66.7%, fire return interval 101–200 years
IV–A	Percentage of replacement fire greater than 80%, fire return interval 36–100 years
IV–B	Percentage of replacement fire greater than 66.7%, fire return interval 101–200 years
V–A	Any severity, fire return interval 201–500 years
V–B	Any severity, fire return interval 501 or more years

[14] www.landfire.gov

Wildfire Risk Assessment

Generally, risk encompasses the likelihood of an event together with the impact of that event.

The likelihood of a wildfire event depends on factors such as ignition risk, fuel source availability, and weather conditions. The impact of a wildfire event includes public safety, physical structures, and environmental consequences.

To enhance the Company's wildfire risk analysis, an independent third party was engaged to perform a wildfire risk assessment across Consumers Energy's service territory. The assessment evaluated both ignition risk and consequence across over 159,000 protective zones, approximately 50 times more granular than FEMA-based assessments. This allows for targeted investments where risk and impact are most significant.

Ignition risk was calculated as the probability of failure times the conditional probability of ignition. A machine learning model was created to estimate the risk of outage failure based on numerous data sets including asset data, operational data, weather data, and vegetation data. To convert the failure probability estimated by the model into an ignition probability, a conditional probability driven by local data observations about historical outages and ignitions within the area of the zone was estimated. Areas of elevated wildfire risk within Consumers Energy's service territory are shown in Figure 8 and classified as very high, high, and moderate.

Figure 8

Ignition Risk in Consumers Energy's Service Territory

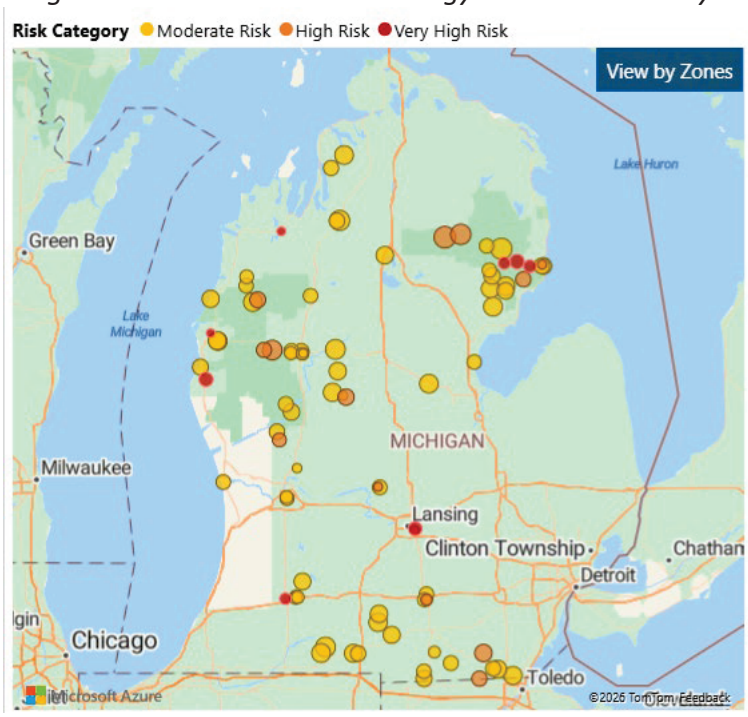
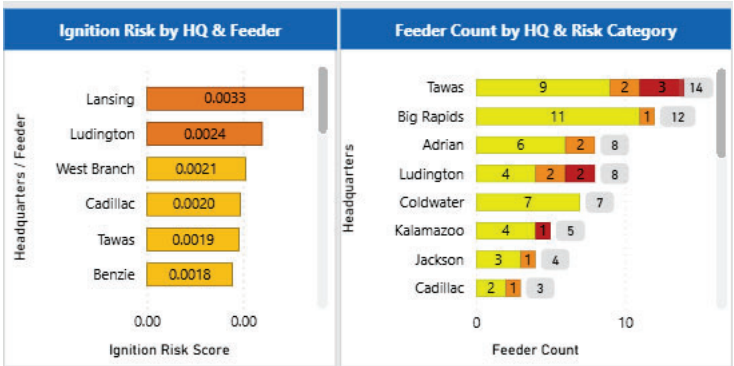


Figure 9 identifies the Lansing, Ludington, West Branch, Cadillac, Tawas, and Benzie headquarters as having the highest ignition risk.

Figure 9

Ignition Risk by Headquarter



Consequence was based on the *National Risk Index* data available from FEMA which includes population consequence, as estimated by a statistical value of life; building consequence; and agricultural consequence.

Total consequence across the territory is estimated at approximately $25.2 billion. Estimated Annual Loss (EAL), defined as consequence multiplied by ignition risk, for Consumers Energy's service territory is approximately $22.0 million. Zones classified as having "Very High" and "High" consequence account for approximately $10.1 billion of total consequence and $12.5 million of EAL. While the highest ignition likelihood is clustered in Lansing, Ludington, and West Branch headquarters, the highest concentrations of EAL are observed in Jackson, Kalamazoo, and Lansing (as shown in Figures 10 and 11 below).

Figure 10

EAL in Consumers Energy's Service Territory

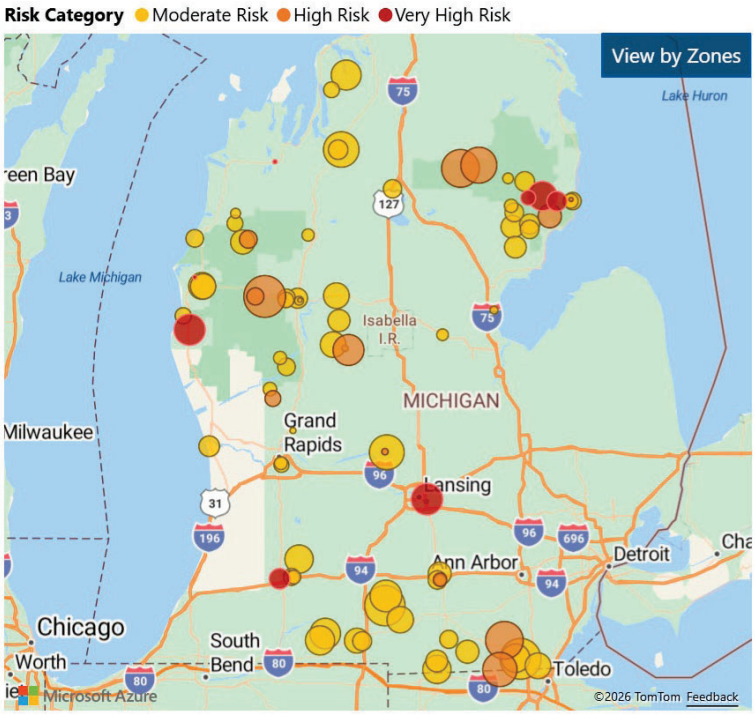
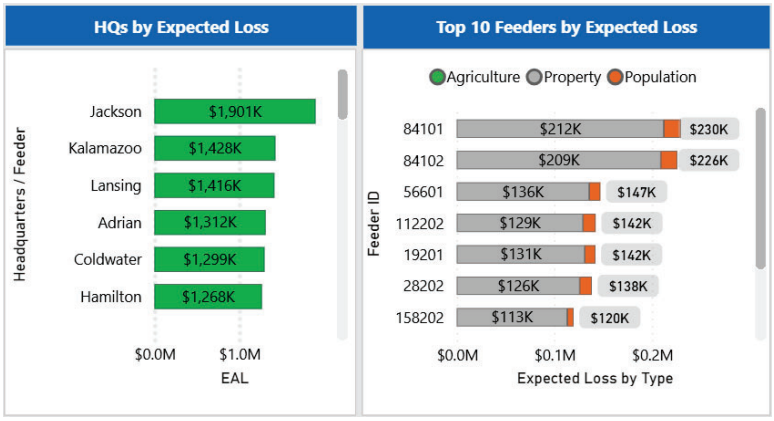


Figure 11

EAL by Headquarter and Type



Once ignition risk, consequence, and EAL were calculated, a benefit-cost analysis was performed by considering the costs of mitigation options within a zone and comparing them to the expected reduction in EAL to derive a prioritization of mitigations by zone to maximize the reduction in wildfire risk.

Based on this benefit-cost analysis, a five-year, approximately $23 million mitigation portfolio is expected to reduce EAL by approximately $0.5 million annually and mitigate approximately $23 million in lifetime losses, delivering a portfolio benefit-cost ratio of approximately 1.0.

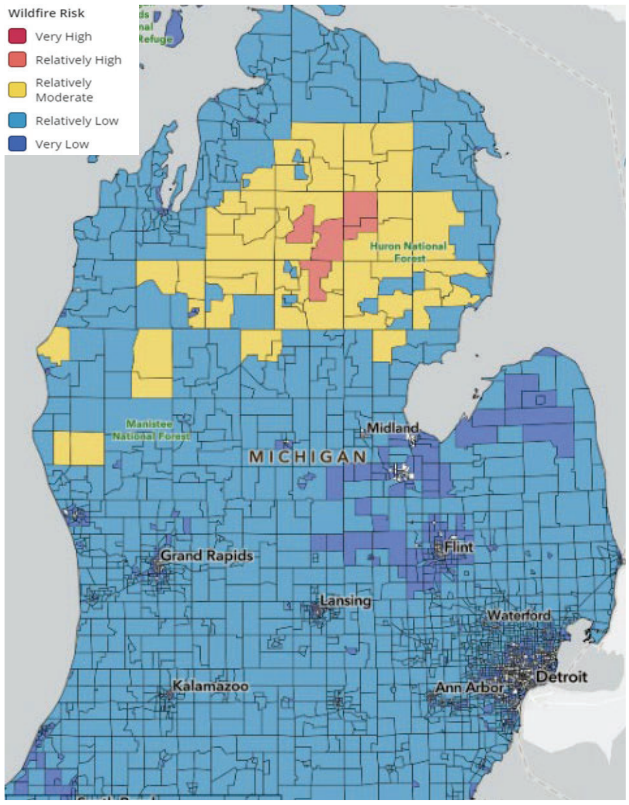
Prior to the third-party, Consumers Energy Territory specific wildfire risk assessment described above, the Company referenced the FEMA *National Risk Index* to assess wildfire risk in Michigan. FEMA publishes a *National Risk Index* map that includes a Wildfire Risk Index score and rating for the United States, representing a community's relative risk for wildfires when compared to the rest of the United States[15]. FEMA updated its *National Risk Index* in December 2025 as shown in Figure 12 below. FEMA wildfire risk now indicates predominantly low to moderate wildfire risk across Consumers Energy's service territory. While FEMA mapping was previously used to inform wildfire risk and investment decisions, the aforementioned assessment is now being used to inform and support the hardening investments outlined in this plan.

[15] Wildfire | National Risk Index (fema.gov)

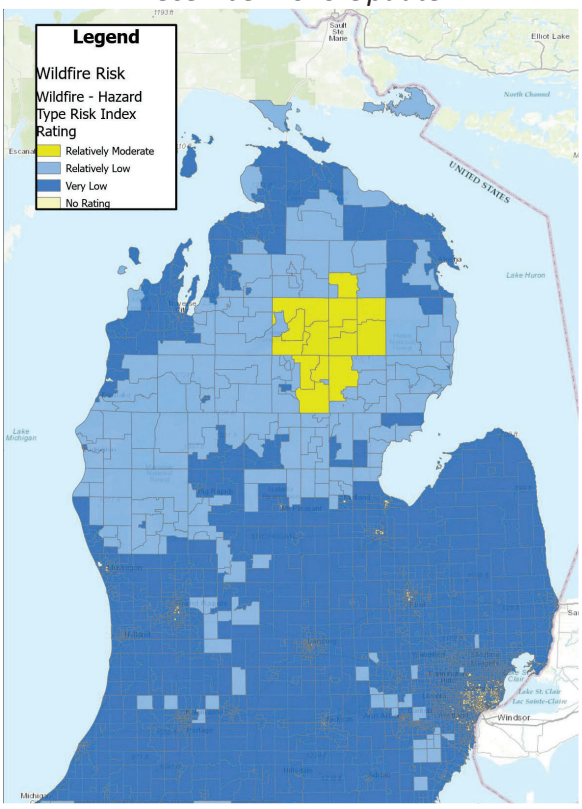
Figure 12

FEMA National Risk Index – Wildfire Hazard

Prior to December 2025



December 2025 Update



Additionally, the Company is collaborating with agencies such as the Michigan DNR, local fire departments, and county emergency managers, to ensure alignment regarding the elevated wildfire risk areas in Michigan and a cohesive effort to reduce wildfire risk in Michigan.

Opportunities to Evaluate

Previously, the FEMA *National Risk Index* map was used in identifying elevated wildfire risk areas to focus on mitigation. In 2026, Consumers Energy used a third-party to identify assets vulnerable to wildfire within elevated wildfire risk areas by using Company-specific data in addition to external data sources mentioned earlier in this section. While the third-party wildfire risk assessment utilized more Consumers Energy-specific data than the FEMA *National Risk Index*, there are still opportunities to incorporate additional data to improve the risk assessment further. For example:

- To build increasingly sophisticated wildfire risk assessment models, the Company will capture and track asset health data using its Asset Repository (“AR”) and Asset Investment Planning (“AIP”). To support all or part of their risk assessment modeling, many utilities in the Western United States use third-party vendors analyzing hundreds of thousands of asset health data inputs and employing machine learning and other advanced techniques. Consumers Energy will continue to evaluate these options as it matures its AR and AIP.
- Localized weather patterns such as wind gust intensities (that can contribute to wire-to-wire

contact) and hot/dry day frequencies can be analyzed to further characterize the ignition risk in these areas. To increase the granularity of weather data, the Company is installing Company-owned weather stations which is discussed in more detail in the Situational Awareness section below. While external weather data was utilized in the third-party wildfire risk assessment, incorporating data from Company-owned weather stations in the future will allow for more localized analysis.

As the Company continues to enhance the wildfire risk assessment with more Consumers Energy-specific information, mitigation activities and investments can be increasingly targeted, and emergency agencies can be made aware of potential risks to public safety, physical structures, the environment, and the electric distribution system—all of which will serve to mitigate wildfire ignition and spread.

Situational Awareness

Situational awareness is the action the Company takes to monitor weather conditions and asset health in elevated wildfire risk areas to support both real-time and longer term operational and investment decisions.

There are a number of situational awareness tools specifically used to mitigate wildfire risk that the Company has identified through benchmarking efforts with other utilities. These include:

- Wildfire-specific weather monitoring
- Weather stations
- Staff meteorologists
- Enhanced inspections
- Fire detection cameras
- Fire spread modeling
- Enhanced wildfire risk modeling

Consumers Energy is currently focused on leveraging weather monitoring, a staff meteorologist, line sensors, and enhanced inspections to mitigate wildfire risk. The Company will continue to evaluate additional situational awareness tools such as expanded use of drones, fire detection cameras, and downed conductor detection technology.

Weather Monitoring

Weather monitoring is critical for wildfire risk mitigation as it helps identify areas and levels of concern that may be used to respond quickly and effectively to real-time changing weather conditions and prioritize mitigation activities.

Consumers Energy has expanded its weather monitoring program to include reviewing *Red Flag Warnings,* using a wildfire-specific weather forecast from DTN, and has an on-staff Company meteorologist with an additional on-staff meteorologist starting in the Summer of 2026. Wildfire-specific weather forecast data is emailed by DTN to the Company twice per day and used to

facilitate real-time adjustments to operational procedures as well as allowing the Company to begin collecting territory-specific wildfire weather data to incorporate into ongoing wildfire risk monitoring. The meteorologist continuously monitors and assesses weather and fire risk conditions. Continuous assessment and weather monitoring, along with situational awareness, may involve, but is not limited to, reviewing information from sources such as DTN, NWS, Meso West, DNR, SPC Maps and Spot Forecast Monitor as well as Resilience Analysis and Planning Tool – Production.

The Company is advancing its weather and wildfire monitoring capabilities through the installation of five weather stations in designated elevated wildfire risk areas. This effort represents the initial phase of a broader deployment strategy, which targets the installation of 100 stations by 2027. These actions align with the initiatives outlined in the Company's Reliability Roadmap.

Company-owned weather stations allow a utility more control and access to more granular weather information. Historically, weather and hazard forecast information is provided by DTN by regions that consist of several counties as shown in Figure 13. This broad view limits the Company's ability to understand in detail. Peer assessments have shown that more granular weather information is beneficial when tracking wildfire risk because both the risk assessment and mitigations can be more specific.

Company-owned weather stations will allow the Company to measure wildfire risk and take mitigation actions in a more targeted way, reducing the negative reliability impacts of some mitigation activities to customers. Consumers Energy Company-owned weather stations were approved in the electric rate case, Case No. U-21870, to support storm response as well as the Company's overall reliability efforts as described in the Company's Reliability Roadmap. The Company will be able to leverage these weather stations for wildfire risk mitigation.

Figure 13

Example of DTN Weather Forecast Report including Wildfire Forecast

Parameter	Region	Day 1	Day 2	Day 3	Day 4	Day 5
Wind Speed	Bay Central	1	1	1	1	1
	Eastern	1	1	1	1	1
	Grand Rapids	1	1	1	1	1
	Lakeshore	1	1	1	1	1
	Northeast	1	1	1	1	1
	Northwest	1	1	1	1	1
	Southern	1	1	1	1	1
	Southwest	1	1	1	1	1
Wind/Gust	Bay Central	1	2	1	1	1
	Eastern	1	2	1	1	1
	Grand Rapids	2	2	1	1	1
	Lakeshore	2	2	1	1	1
	Northeast	1	1	1	1	1
	Northwest	2	2	1	1	1
	Southern	2	2	1	1	1
	Southwest	2	2	1	1	1
Wildfire	Bay Central	4	1	1	1	1
	Eastern	4	1	1	1	1
	Grand Rapids	4	1	1	1	1
	Lakeshore	4	1	1	1	1
	Northeast	4	1	1	1	1
	Northwest	4	1	1	1	1
	Southern	4	1	1	1	1
	Southwest	4	1	1	1	1
Snow	Bay Central	1	1	1	1	1
	Eastern	1	1	1	1	1
	Grand Rapids	1	1	1	1	1
	Lakeshore	1	1	1	1	1
	Northeast	1	1	1	1	1
	Northwest	1	1	1	1	1
	Southern	1	1	1	1	1
	Southwest	1	1	1	1	1
Ice	Bay Central	1	1	1	1	1
	Eastern	1	1	1	1	1
	Grand Rapids	1	1	1	1	1
	Lakeshore	1	1	1	1	1
	Northeast	1	1	1	1	1
	Northwest	1	1	1	1	1
	Southern	1	1	1	1	1
	Southwest	1	1	1	1	1
Confidence Level	Bay Central	Medium	Medium	High	High	High
	Eastern	Medium	Medium	High	High	High
	Grand Rapids	Medium	Medium	High	High	High
	Lakeshore	Medium	Medium	High	High	High
	Northeast	High	Medium	High	High	High
	Northwest	Medium	Medium	High	High	High
	Southern	Medium	Medium	High	High	High
	Southwest	Medium	Medium	High	High	High

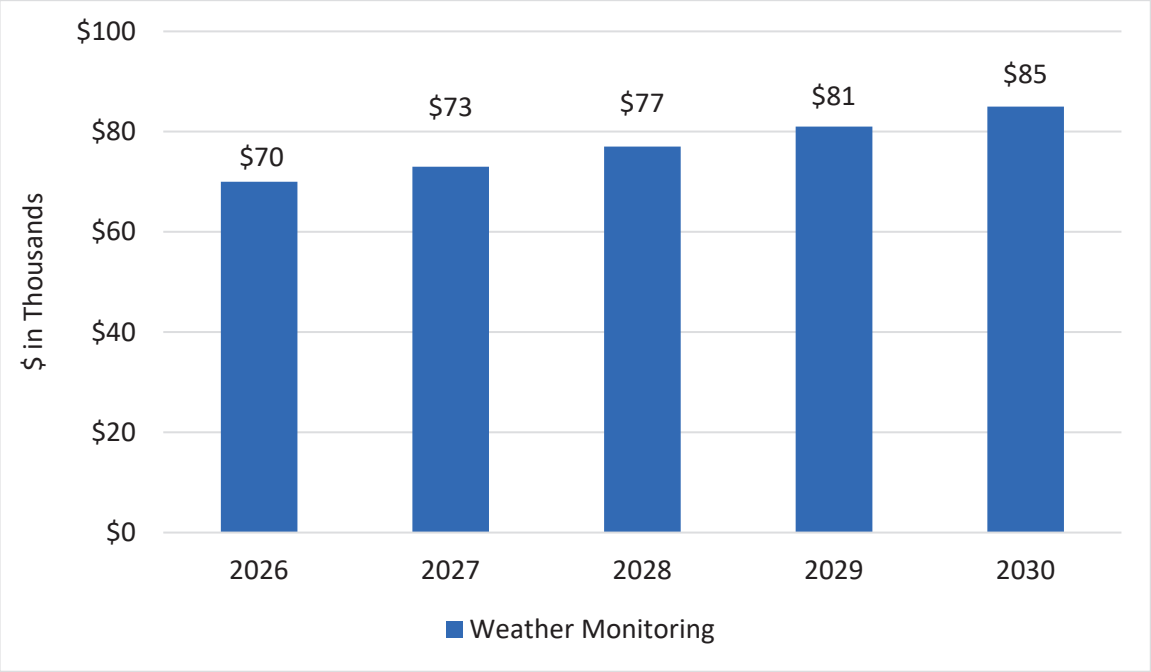
Company-owned weather stations may be positioned in a way to extract territory-specific real-time weather data that can be recorded to allow staff meteorologists to specialize in real-time weather patterns as well as analyze historical data trends in Consumers Energy's territory.

Additional localized detail would create more insight into weather conditions that lead to wildfire risk, and would allow the Company to refine operational procedures and better target system hardening to enhance wildfire risk mitigation.

The costs for the wildfire-specific weather forecast from DTN are shown in Figure 14 below. The cost to install Company-owned weather stations is not included in this wildfire risk mitigation plan.

Figure 14

Weather Monitoring O&M Plan



Line Sensors

Line sensors are inductively charged devices installed on the overhead primary conductor of the LVD distribution system. They are used to remotely monitor electrical current and detect sustained, momentary, and potential faults, improving the capability to respond quickly and reduce customer outages. Line sensors also capture data points such as amperage, conductor temperature, phase imbalance mis-phasing, and load flow direction.

Adding line sensors to LVD distribution lines in the elevated wildfire risk area allows the Company to reduce ignition risk by remotely monitoring the current conditions of the distribution primary conductor, as well as monitoring for potential faults, which will allow the Company to quickly respond before a failure occurs.

Consumers Energy has prioritized the elevated wildfire risk areas for the installation of line sensors on circuits. The Company will continue to evaluate opportunities to install additional line sensors on these circuits to provide additional insight and remote monitoring capabilities.

Enhanced Inspections

'Enhanced inspections' refer to increasing the frequency of LVD line inspections and correcting identified failures to reduce wildfire risk. Line inspections are currently conducted on a two-year cycle and include visually observing LVD distribution lines and supporting infrastructure to identify potential issues with equipment.

Consumers Energy is inspecting highest risk miles annually as a part of our LVD lines inspections program. By increasing the frequency of these inspections, the Company will reduce risk by identifying and mitigating the potential for ignition risk as well as fuel sources such as dead trees and overgrown vegetation.

As stated in the Company's Reliability Roadmap, Consumers Energy will improve the inspection process, using drones in a much more widespread manner, while investing in automation and machine learning to increase the efficiency with which defects are identified. The enhanced inspections in elevated wildfire risk areas will benefit from these advancements.

Opportunities to Evaluate

The Company will continue to evaluate other situational awareness tools such as expanded use of drones, fire detection cameras, and downed conductor detection technology as well as continue to benchmark and collaborate with Edison Electric Institute ("EEI") and Electric Power Research Institute ("EPRI") to identify new technologies and best practices for wildfire risk mitigation.

Drones can be used in a variety of ways to expedite or enhance inspections and investigations as described in the Company's Reliability Roadmap. One way the Company may consider using drones to reduce wildfire risk is to use a thermal camera drone to detect hotspots or failing equipment invisible to the naked eye. This technology may be particularly useful during outage or disturbance investigations. The Company will continue to evaluate the benefits of using thermal camera drones in elevated wildfire risk areas.

Fire detection cameras are automated cameras connected to an artificial intelligence engine that detects smoke within a specific mileage radius. These cameras support wildfire risk mitigation by sending fire location information to any stakeholders identified to receive the information. This early warning and detection technology is used by many utilities in the western part of the United States who have distribution and transmission systems in less densely populated areas to find and respond to wildfires quickly and effectively. The Company would need approximately 135 cameras to adequately cover the elevated wildfire risk areas at a cost of approximately $7 million. Consumers Energy will continue to evaluate the benefits of fire detection cameras in elevated wildfire risk areas.

Downed conductor detection technology is an important tool to reduce ignition risk for wildfire risk mitigation. High-impedance fault situations, such as downed live conductors, are challenging to detect because they do not result in large enough fault current for traditional protection devices to sense. The potential for detecting and isolating high-impedance faults is improved with downed conductor technology. Installation of this technology can improve public safety and reduce the risk of fire from a downed live conductor. The implementation and method of this technology depend on the controller hardware and vendor. Consumers Energy will continue to evaluate the implementation of downed conductor detection technology in elevated wildfire risk areas.

Operational Procedures

Consumers Energy has put operational procedures in place to both mitigate ignition risk depending on the magnitude of wildfire risk at a specific time, and to respond to a wildfire event quickly and effectively to minimize harm to the public, physical structures including the electric distribution system, and the environment.

The Company has also established various thresholds to monitor increasing wildfire risk in real-time, and operational procedures at those thresholds to mitigate an increased risk of wildfire. The Company has implemented a *Red Flag Warning* response, wildfire-specific emergency response plan as part of the Company's *Electric Emergency Response Plan,* and a *Public Safety Power Shutoff* policy.

Elevated Wildfire Risk Thresholds

The situational awareness tools outlined previously will identify increasing wildfire risk in real-time. To effectively respond to any risk level appropriately, it is important to define levels or thresholds of risk.

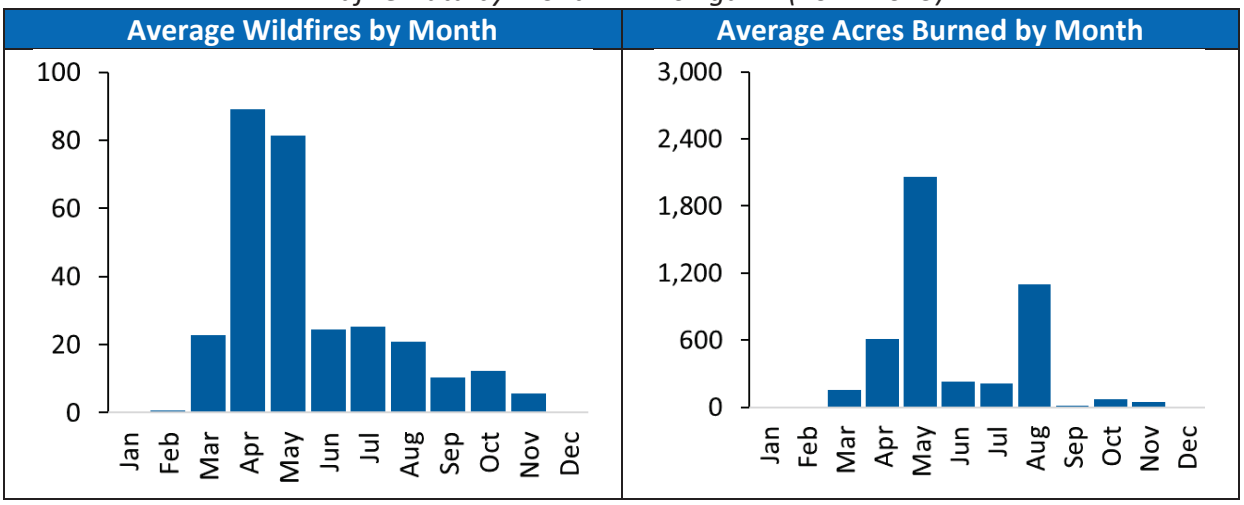
Thresholds of wildfire risk used by other utilities include:

- Wildfire risk area: Designated by a third-party such as FEMA or proprietary analysis
- Wildfire season: Designated by third-party state agency or proprietary historical analysis
- Red Flag Warnings: Issued by the National Weather Service
- Unique thresholds: Based on a combination of weather conditions such as temperature, wind speed, and humidity as well as ignition risk measures like level of fuel moisture

As described in the Risk Assessment and Mapping section above, wildfires are most likely to occur in March through August based on historical Red Flag Warnings and wildfire frequency. This is further supported by the cumulative acres burned per month historically as shown in Figure 15.

Figure 15

Wildfire Data by Month in Michigan[16] (2012-2025)



Operational Procedures to Mitigate Wildfire Risk

There are several increasingly impactful operational procedures the utility industry is using to mitigate wildfire risk, including responding to Red Flag Warnings, modifying field operations,

[16] Michigan Department of Natural Resources Fire Report Dashboard

adjusting recloser settings, and implementing public safety power shutoff ("PSPS") events.

The Company has developed procedures for these mitigation activities to ensure when they are employed, they will maximize wildfire risk mitigation and minimize impact to customer experience and reliability.

Red Flag Warning Response. The Company has established a Red Flag Warning response plan that incorporates monitoring potential and actual weather conditions and initiates wildfire mitigation actions on circuits identified to have higher wildfire risk. Red Flag Warning conditions are monitored by senior Control Center staff who are on-shift 24 hours a day, 7 days a week. Upon notification of a Red Flag Warning in areas of the state where higher wildfire risk circuits exist, the response plan is initiated with the target to put mitigation actions in place for the duration of the Red Flag Warning event. Mitigating actions include:

- Applying the Hot Line Tag function to substation reclosers to make fault condition device tripping schemes more sensitive and to clear faults more quickly;
- Blocking Automatic Transfer Recloser loop schemes from operating automatically and transferring power from adjacent circuits;
- Stopping hot work on energized lines on the identified circuits;
- Staging field personnel at substations and LVD line sections to respond to outages and hazards; and
- Initiating Public Safety Power Shutoff (PSPS) in only the most extreme wildfire conditions.

Field Operations. As the wildfire risk increases, many utilities modify their field operating procedures to reduce the risk of ignition from utility infrastructure or operations. Modifications include changes to requirements for:

- Open fire/burning
- Presence and use of firefighting tools
- Smoking
- Fire extinguishing
- Off-road vehicle travel
- Off-road equipment use
- Scheduled customer work or construction
- Timing of work
- Worksite preparation
- Hot work
- Line testing
- Blasting, grinding, and welding
- Line clearing activities

The Company has field operations standards during Red Flag Warnings in elevated wildfire risk areas including:

- Operations personnel will be placed and assigned to areas identified as elevated risk;
- Any risk identified will be discussed with Electric Operations Supervisor to determine urgency of repair;
- Types of field operations work permitted during elevated risk; and
- Primary outages may be restored after all primary has been inspected via stepped restoration.

If Operations responds to an emergent job that is involved in a fire, there are steps to follow, including:

1. Make the scene safe.
2. Request fire department response to ensure risk of re-ignition is mitigated.
3. Contact Electric Operations Supervisor and escalate to Senior Manager or On-Call Incident Commander.

Some aspects of the Company's standard operating procedures inherently take wildfire risk into account, like line clearing activities. The *Forestry Line Clearing Program* at Consumers Energy uses experienced line clearing vendors that have their own tactics for wildfire risk mitigation. Some of these tactics include:

- Employees must be aware of the *Fire Danger Index* at the beginning of each workday.
- Employees complete standard fire prevention awareness and training, including the proper use of fire extinguishing equipment.
- Employees inspect fire extinguishing equipment regularly and repair or replace the equipment as needed.
- A designated individual is required to be assigned to fire watch duty when the fire danger level is high, very high, or extreme, and shall observe and monitor the work site for smoldering.
- Employees are informed of the proper actions to take in the event of a fire. This includes, but is not limited to, notification and evacuation procedures. It is stressed that at no time does the task of fighting fire supersede an employee's primary duties of ensuring their own personal safety and the safety of others. It is required to report the incident to the proper authority and ensure personal accountability for self and others at the jobsite, in accordance with company policy.

Standard operating procedures may change as Consumers Energy evaluates and implements wildfire risk mitigation standards for field work being done by internal and contracted employees.

Recloser Settings. *Recloser settings* refer to the operational sequence and sensitivity of reclosers on the distribution system.

Reclosers open when a fault occurs and then will reclose, based on the operation sequence settings. Once a recloser opens, the line is de-energized until it closes again. Recloser operation

sequence settings can be adjusted to change the response time characteristics for a fault and the number of reclose attempts.

Since most distribution faults are temporary, reclosers generally improve customer reliability by clearing faults without a sustained outage. However, upon the initial fault or if the fault is still present when the device recloses, there is a possibility sparks or arcing may occur, presenting ignition risk. To limit this ignition risk, reclosers can be set to "lock out" (remain open) upon a single trip event, until the line can be visually inspected.

Fast trip settings can also have a wildfire risk mitigation benefit. Enabling fast curve settings will cause the device to trip faster when a fault occurs, reducing the amount of energy released into a fault. Fast trip settings can reduce ignition risk, but such settings will be detrimental to reliability due to manual circuit inspections before manually reclosing when in use.

Setting automatic reclosing to lock out upon a single trip event or enabling fast trip settings will reduce wildfire risk during elevated wildfire risk conditions by reducing ignition risk. However, it is important to note that increasing the sensitivity of recloser settings in this way results in more interruptions for customers who will require service restoration. Line sensor deployment and subsequent utilization are important in helping to identify fault locations when fast trip settings are enabled.

As part of the Company's Red Flag Warning response, substation reclosers are set to Hot Line Tag ("HLT") mode during qualifying wildfire conditions. HLT operates in a one-shot mode, tripping all phases extremely quickly when a fault is detected, and prevents the recloser from being reclosed.

Experience with HLT settings revealed that substation reclosers have limited reach and may not be able to detect faults at the end of some circuits, leaving those portions of the line without the extremely fast tripping provided by HLT. Consumers Energy is working to enhance the protection plan under the *Red Flag Warning* response to address this limitation.

Consumers Energy is also evaluating different wildfire protection strategies recommended by EPRI, such as *relatively fast* clearing times compared to *extremely fast* clearing times. Relatively fast clearing times will still clear as fast as possible while maintaining some level of coordination with other protective devices on the circuit. Having this level of coordination will allow for faster fault locating and dispatching.

Utilities in the Western United States have employed modified recloser settings to mitigate increasing wildfire risk, as well as reduce the need to implement PSPS events. They continue to test and analyze the best settings for different combinations of weather conditions, fuel availability, and electric distribution system considerations to optimize for both wildfire risk mitigation and customer reliability.

Consumers Energy will continue to incorporate new information and industry learnings into its ongoing efforts to refine its protection strategy to ensure both safety and reliability.

Consumers Energy Control Centers use Supervisory Control and Data Acquisition (SCADA) to communicate with and control devices on the electric distribution system. Many substations in Consumers Energy's electric service territory have electronic automatic reclosers with SCADA capability. This capability allows remote de-energization of a substation and all distribution lines

connected to the substation. Reclosers are also installed on distribution lines, but they are not all electronic reclosers. Only electronic reclosers have SCADA capability. The Company is evaluating adding SCADA functionality to existing LVD line reclosers and ensuring future line reclosers are SCADA ready.

Adding SCADA capability to LVD distribution lines allows remote sectionalization of distribution lines, minimizing the impact of an outage and decreasing the need for crews to manually adjust reclosers. SCADA capability will be crucial to allow remote changes of line recloser settings during high-risk wildfire conditions in a practical amount of time. Changing line recloser settings to fast trip settings will result in an increase in outages and the Company will adjust service restoration procedures accordingly to combat any reliability impact.

Public Safety Power Shutoff. PSPS refers to the total de-energization of sections of the distribution system during extreme wildfire conditions. This de-energization has the potential to remove power from thousands of customers as a pre-emptive wildfire risk mitigation effort. It is an extreme action that should only be undertaken after very careful consideration of the threat and impact of a wildfire on life and property.

While many of the utilities in the Western United States have deployed this tactic in recent years, their current focus is on reducing the need for this tool by mitigating wildfire risk in other ways, including refining their approach to adjusting system settings (e.g., recloser settings) to maximize wildfire risk mitigation and reliability.

The Company has established a *Public Safety Power Shutoff (PSPS)* policy that allows for the targeted de-energization of power in specific areas during periods of elevated wildfire risk to reduce the potential for electrical ignition. While PSPS can be very effective at mitigating wildfire risk, it can also negatively impact customers who depend on the Company to deliver reliable power. This procedure will be a last resort and only used in extreme wildfire weather conditions.

Emergency Response

Emergency response refers to actions the Company takes to respond to a wildfire event. In any incident, response activities are prioritized based on:

1. Life safety
2. Incident stabilization
3. Property/Environmental preservation

Outlined in the *Wildfire Hazard Specific Annex* is a recommended structure of command, staffing, suggested incident objectives, and actions that must be taken to return the Company to normal operations. This includes internal and external notifications, information assistance, and collaboration with relevant local agencies.

This annex is housed within the Company's overarching *Electric Emergency Response Plan*. The annex was developed by the Emergency Management Program in coordination with Electric Operations to align with the FEMA's National Incident Management System ("NIMS") and the Company' Incident Command System ("ICS").

NIMS guides all levels of governmental and non-governmental organizations and the private sector to work together to prevent, protect against, mitigate, respond to, and recover from

incidents. The structure of the ICS activation is similar to the storm response operations that the Company described in the Reliability Roadmap.

System Hardening for Wildfires

System hardening for wildfires is improving, modernizing, and hardening the distribution system with wildfire risk mitigation as a prioritized concern.

Based on industry research and benchmarking, system hardening best practices for wildfire risk mitigation include:

- Further sectionalizing the distribution system
- Fractionalization of substations and circuits
- Enhancing pole inspections and remediations
- Undergrounding overhead lines
- Replacing traditional expulsion fuses
- Installing covered conductor
- Constructing microgrids

Consumers Energy is investing in a layered approach to strengthen overhead lines and harden the distribution system by undergrounding overhead lines, installing covered conductor, and adding or replacing protective line devices within the elevated wildfire risk area. The goal of this layered approach is to help mitigate contact with tree limbs and other foreign objects that may lead to wildfire ignition, and to minimize the impact this contact may have on the distribution system and the customers we serve.

Consumers Energy will prioritize investment according to ignition risk and consequence.

The Company will continue to evaluate additional system hardening best practices such as enhancing pole inspections, replacements, and constructing microgrids.

Undergrounding

Undergrounding overhead conductor has been identified by multiple utilities as the best practice for wildfire risk mitigation. By undergrounding overhead conductor, the largest contributor to wildfire ignition from a powerline, foreign objects touching overhead conductor, is eliminated and Consumers Energy expects to see fewer faults and ignitions in those areas.

The third-party wildfire risk assessment currently identified 20 zones consisting of 11.2 miles to underground for wildfire risk mitigation.

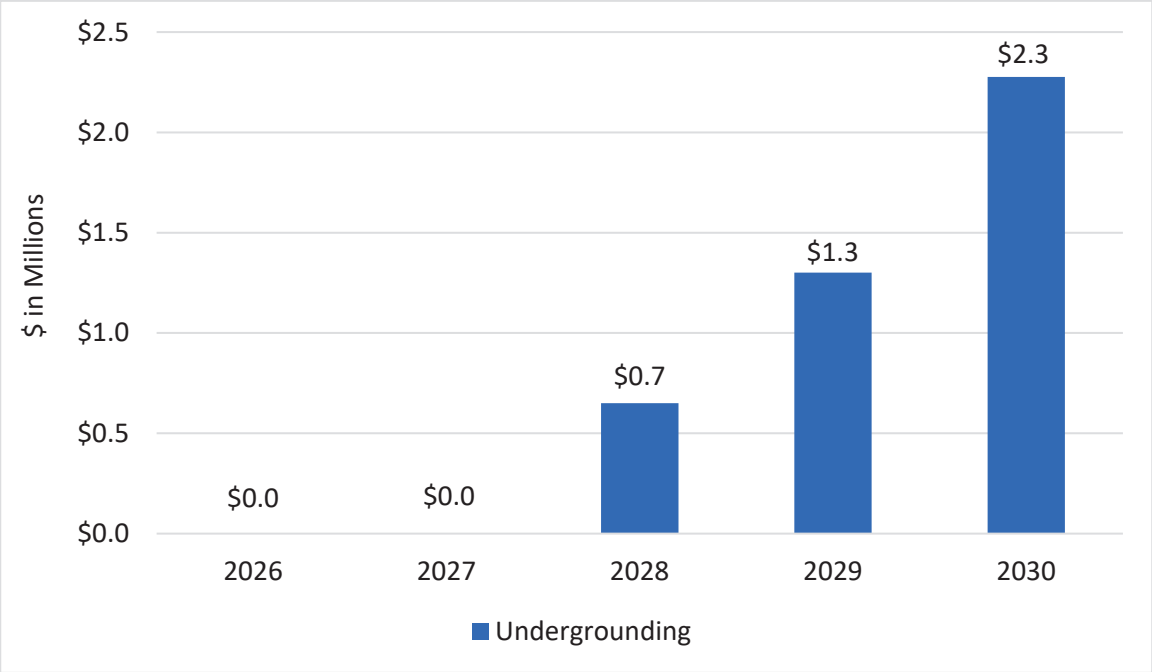
Consumers Energy will begin undergrounding these zones in 2028. Line miles will be prioritized by ignition risk and consequence as well as operational considerations given undergrounding overhead conductor requires specific resources and permits to construct.

Additional miles may also be undergrounded each year in wildfire risk areas through the resiliency efforts outlined in the Company's Electric Rate Case. These projects would be specifically chosen for resiliency, but provide benefits to both resiliency and wildfire risk

mitigation endeavors. The 5-year investment plan for undergrounding is shown in Figure 16.

Figure 16

Undergrounding Capital Investment Plan



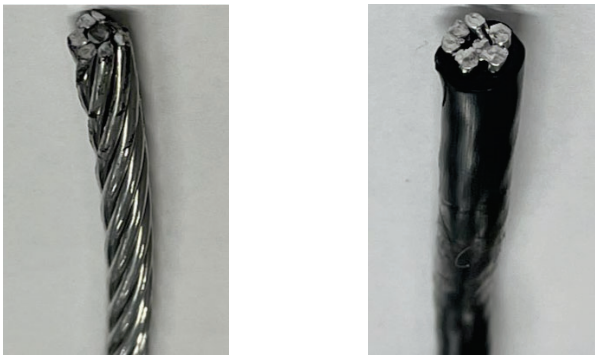
Covered Conductor

Covered conductor is a conductor cable design that includes a polymer sheath on the external portion of the wire to protect against incidental contact with trees and other vegetation.

Figure 17 is an example of covered conductor next to bare or traditional conductor. Covered conductor has multiple advantages over traditional conductor, and is typically used to increase system reliability and mitigate the probability of ignition from vegetation caused arcing.

Figure 17

Bare versus Covered Conductor



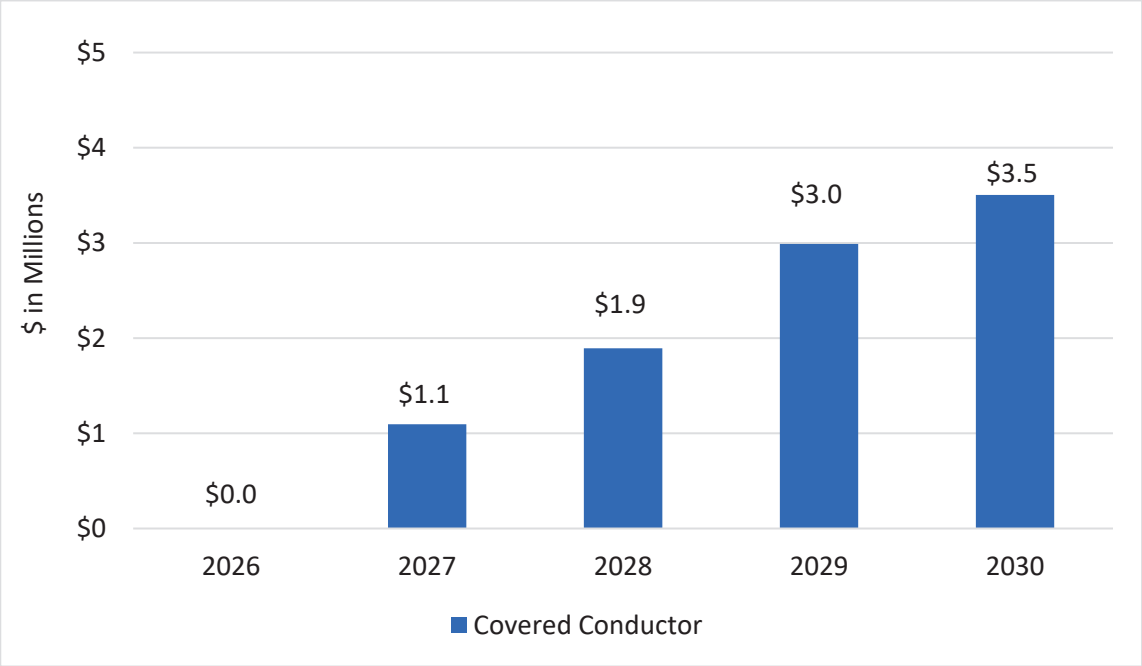
The third-party wildfire risk assessment identified 33 zones consisting of 55.6 miles to install covered conductor for wildfire risk mitigation.

Consumers Energy will begin installing covered conductor in these zones in 2027. Line miles will

be prioritized by ignition risk and consequence as well as operational considerations. The 5-year investment plan for covered conductor is shown in Figure 18.

Figure 18

Covered Conductor Capital Investment Plan



Protective Line Devices

Consumers Energy has a large distribution network providing service to the majority of Michigan's lower peninsula. This large network can experience faults on the system caused by a wide range of factors. When faults on the distribution system occur, the distribution system primarily relies on sectionalizing devices to protect the system. Automatic sectionalizing devices, including fuses, sectionalizers, and reclosers maintain electric service reliability by isolating faulted sections of the system. Manual sectionalizing devices, including disconnect and load-break switches, provide a convenient means of changing system connections.

Fuses. The majority of the fuses currently on the distribution system are *expulsion fuses* that are designed to operate by creating an expulsion within the fuse, resulting in the fuse isolating the fault, see Figure 19.

When an expulsion occurs, the molten material within the fuse is discharged out of the fuse casing through a venting system in the bottom of the fuse cylinder and could ignite nearby fuel sources. Due to this ignition risk, CAL FIRE and other wildfire protection organizations in the western United States have safety requirements for the use of expulsion fuses, and utilities in the western United States are actively replacing expulsion fuses with non-expulsion fuses.[17]

To best mitigate the possibility of ignition resulting from these devices, Consumers Energy is evaluating their replacement within elevated wildfire risk areas. This includes benchmarking other utilities and fuse options to identify the most effective non-expulsion alternatives. Among

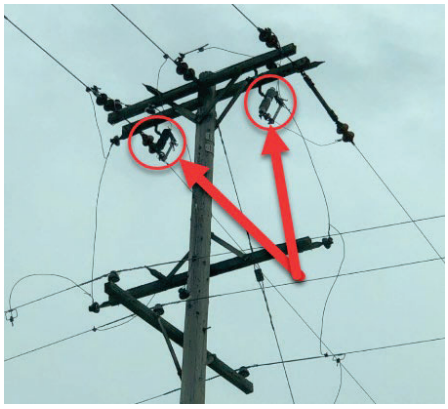
[17] California Power Line Fire Prevention Field Guide

these options, Consumers Energy is exploring full-range current-limiting fuses, such as the ELF Fuse by Eaton Cooper, which fits into a standard cutout. These devices provide a safer alternative for wildfire-prone areas and align with best practices highlighted by EPRI for reducing risks associated with expulsion events and potential ignition hazards.

Industry benchmarking has shown that a peer utility has implemented a complementary, application-based fusing strategy in elevated wildfire risk areas that uses the non-expulsion full-range current-limiting Eaton ELF fuses for lower-load locations (such as pole-top transformers and lightly loaded laterals) while applying non-expulsion SMU power fuses at higher-load locations where current-limiting fuse ratings are exceeded. This combined approach allows ignition risk to be reduced across a greater portion of distribution circuits while preserving protection coordination, device reach, and system reliability. Informed by this collaboration and benchmarking, Consumers Energy is investigating a similar non-expulsion fusing strategy for application in elevated wildfire risk areas.

Figure 19

Lateral Expulsion Fuse Installation (2-phase)



Reclosers. Reclosers are single-phase or three-phase interruptive devices installed in substations or on primary lines for circuit sectionalizing. As discussed in the Operational Procedures section, electronic recloser settings can be adjusted to mitigate ignition risk in elevated wildfire risk conditions.

Installing three-phase electronic reclosers, as shown in Figure 20 below, to LVD distribution lines in elevated wildfire risk area allows the Company to adjust protection settings for only a portion of a circuit, rather than the entire circuit using a substation recloser.

Figure 20

Recloser Installation



Consumers Energy is considering insights from EPRI to ensure reclosers are applied and configured to avoid the risks they highlight, particularly those related to energized downed conductors[18].

- Compact single-phase reclosers can unintentionally re-energize downed conductors under certain conditions, increasing public safety risks.
- Furthermore, smaller or aging conductors are more vulnerable to failure during fault events, which can result in energized downed lines.

To address these insights while preserving the operational and wildfire mitigation benefits of compact reclosers, Consumers Energy is evaluating controls such as disabling automatic reclosing functionality in elevated wildfire risk areas and configuring selected devices for single-shot or non-reclosing operation. By refining recloser settings, evaluating line conditions, and carefully assessing deployment locations, Consumers Energy is ensuring these devices are strategically implemented to enhance safety and reliability while mitigating potential risks.

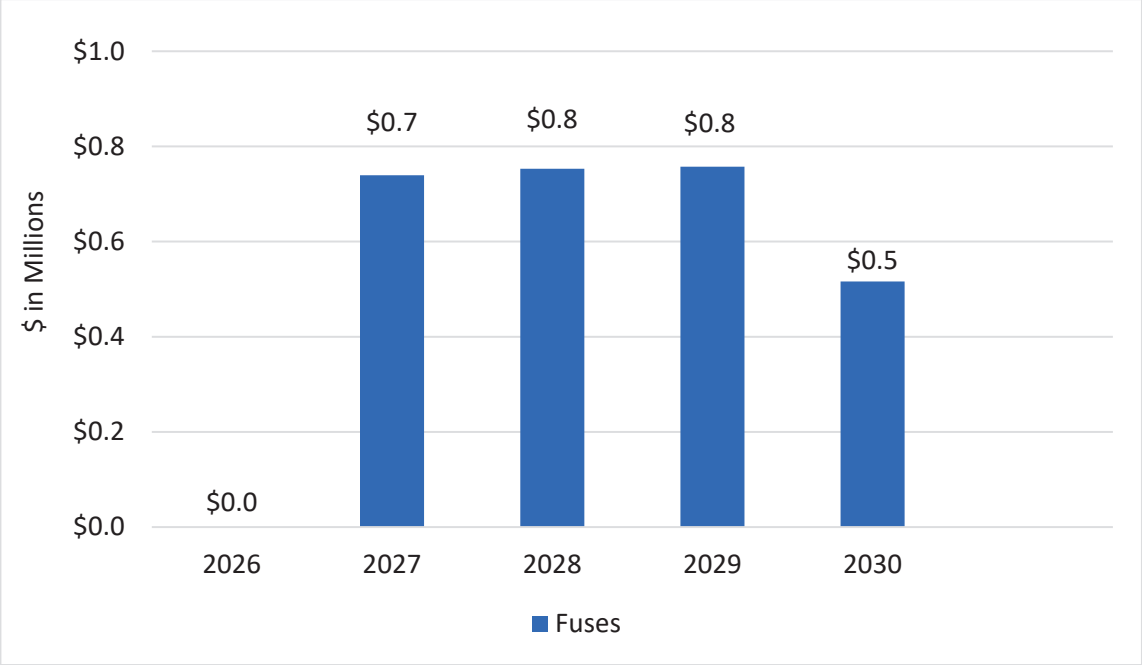
The third-party wildfire risk assessment identified over 1,800 fuses to replace for wildfire risk mitigation. While the Company will continue to evaluate deploying reclosers for wildfire risk mitigation, it is not currently proposing recloser investment because the third-party wildfire risk assessment benefit-cost analysis was based on reducing ignition risk, and the Company currently believes the most value for deploying reclosers for wildfire risk mitigation is reducing customer outage minutes.

The 5-year investment plan for protective line devices is shown below in Figure 21.

[18] EPRI - Wildfire Protection Strategies for Overhead Bare Wire Power Systems, August 2024

Figure 21

Protective Line Devices Capital Investment Plan



Voltage Conversions

The Company's three standard voltages, 4.8/8.32 kV, 7.2/12.47 kV, and 14.4/24.9 kV, comprise the majority of LVD overhead primary line miles in the elevated wildfire risk area. However, there are some line miles configured as Delta systems that are less safe to operate compared to a grounded wye system.

As described more fully in the Reliability Roadmap, by converting non-standard components to one of the three standard voltages, the Company will mitigate the safety risk from ungrounded wires and increase operational flexibility by expanding the ability to transfer loads to reduce outage times. This will support wildfire risk mitigation by preparing the circuits for more controllability to execute wildfire risk mitigation operational procedures, and reduce ignition risk from ungrounded wires. Consumers Energy is evaluating the use of voltage conversions as a part of our reliability plan.

Opportunities to Evaluate

The Company continues to evaluate additional ways to use system hardening to mitigate wildfire risk by benchmarking with other utilities, researching technology, and collaborating with EEI and EPRI to identify new technologies and best practices. While Consumers Energy will refine plans for undergrounding, covered conductor, and protective line devices based on learnings from initial investments, the Company is also evaluating increasing pole inspections and replacements and microgrids in elevated wildfire risk areas.

Wooden utility poles have been in consistent use within Michigan for decades, and it is estimated that there are more than 2 million throughout the state. These poles support the distribution network of electric utilities as well as telephone companies and Internet providers.

Inspecting and replacing poles as needed is a priority for Consumers Energy. The Reliability Roadmap includes a plan to inspect LVD poles on a 12-year cycle to identify and replace all rejected poles that do not meet *National Electric Safety Code* ("NESC") standards.

With the current inspection and replacement program in place, Consumers Energy will continue to evaluate whether an enhanced wildfire specific pole inspection and replacement plan should be implemented in elevated wildfire risk areas.

Ductile iron poles could be a replacement for the standard wooden poles currently used, and are being evaluated as a potential option for mitigating wildfires. The benefit of iron poles is the durability, life span, and reduction in potential fuel for a wildfire.

Fractionalization is the practice of segmenting circuits into smaller sections with fewer customers to reduce the number of customers impacted by single contingency outages and customer exposure to outages.

As the distribution system has been expanded over many years to meet the requirements of connecting new customers, there is a subset of circuits with disproportionately high customer counts and overhead line exposure, resulting in challenges due to the underlying system configuration. Limiting the number of customers impacted by any single outage is growing in importance as increasing recloser sensitivities to mitigate wildfire risk will likely result in more outages.

Microgrids provide power to critical facilities and infrastructure when a line is de-energized or there is some other emergency that causes electricity not to be available. Microgrids are self-contained grids which can connect or disconnect from the larger grid and still provide power usually from a battery or renewable power source. Other utilities are using microgrids to reduce wildfire ignition risk as well as provide back-up power to strategic locations during times of emergency or outage.

A microgrid would enable power to continue to be used in areas that may have been isolated by surrounding wildfires, diminishing the effects of power outages, and allowing emergency responders to continue to use facilities that might be unavailable during a power outage.

Microgrid solutions to mitigate wildfire risk include remote microgrids, grid-connected microgrids, and microgrid incentives.

- *Remote microgrids* are not connected to the utility electric distribution system and operate in isolation.
- *Grid-connected microgrids* are connected to the utility electric distribution system, but they may be separated from the distribution system as needed.
- *Microgrid incentives* are to fund third-party owned microgrids.

Line Clearing

Line Clearing Program for Wildfire Risk Mitigation

Trees are one of the greatest causes of interruptions to electric service for customers on the LVD system, contributing 42.1% of all-weather outages and 35.8% of all non-Major Event Day

("MED") outages[19].

The Company clears vegetation within a 30-foot-wide right-of-way ("ROW") for primary voltages to attain a minimum of 10 feet of separation between conductors and vegetation at the time of clearing, and to maintain accessibility along the ROW for maintenance and repair of the line.

The Company has been defining plans in its electric rate cases starting in 2020, and in the Electric Distribution Infrastructure and Investment Plans/Reliability Roadmap starting in 2021, to achieve and maintain a 7-year effective clearing cycle for its LVD system. In Case No. U-21585, the Company proposed moving LVD circuits that intersect with elevated wildfire risk areas to a 5-year clearing cycle.

Referring to the Order in MPSC Case No. U-21870, the Company is beginning to execute on an enhanced line clearing strategy for the entirety of its LVD system: ramping-up to achieve a 5-year clearing cycle and performing more aggressive line clearing on targeted 3-phase primary lines. The projected timeline to achieve the shortened line clearing cycle and scope of more aggressive line clearing targets the end of the 2030-2031 test period. This strategy encompasses the LVD system and therefore includes circuits intersecting with elevated wildfire risk. While the Company is projecting to achieve the reduced cycle strategy by the end of the 2030-2031 test period for all LVD circuits, the Company is prioritizing elevated wildfire risk areas through a more aggressive timeline. Leveraging available analyses, the Company plans to achieve the five-year cycle in elevated wildfire risk areas earlier (i.e., by year-end 2028).

A reduced clearing cycle for circuits intersecting the elevated wildfire risk areas decreases the chance of tree-conductor contact, thereby reducing the potential of a spark igniting a wildfire. The expense projected to achieve the shortened line clearing cycle is outlined in the Reliability Roadmap.

The Company is proposing to continue capturing LiDAR imagery on LVD primary miles on circuits that intersect with areas of elevated wildfire risk. The purpose of capturing LiDAR is to inform and support the execution strategy of the line clearing tactics described above. Figure 2 above includes the estimated annual O&M cost for LiDAR collection and processing. In Case No. U-21870, the Company outlined $0.50 million for LiDAR in this area, and it is updating this projected annual expense to $0.51 million to reflect inflation.

In 2025, the Company worked with a vendor that performed LiDAR collection via fixed-wing aircraft during the leaf-on season. The data processing of raw LiDAR point cloud data included three-dimensional ("3D") modeling and classification of poles and wires relative to nearby vegetation. Classified points were then transformed into actionable insights, including volumetric encroachment measurements and span-level risk scores. As this is the first LiDAR data captured on the LVD system for this purpose, the Company is conducting pilot exercises to test and evaluate intervention methods utilizing this data, which may include, but not be limited to:

- Sequencing line clearing by prioritizing pockets of high span-level risk scores first when conducting full circuit clearing on workplan circuits where possible, given environmental

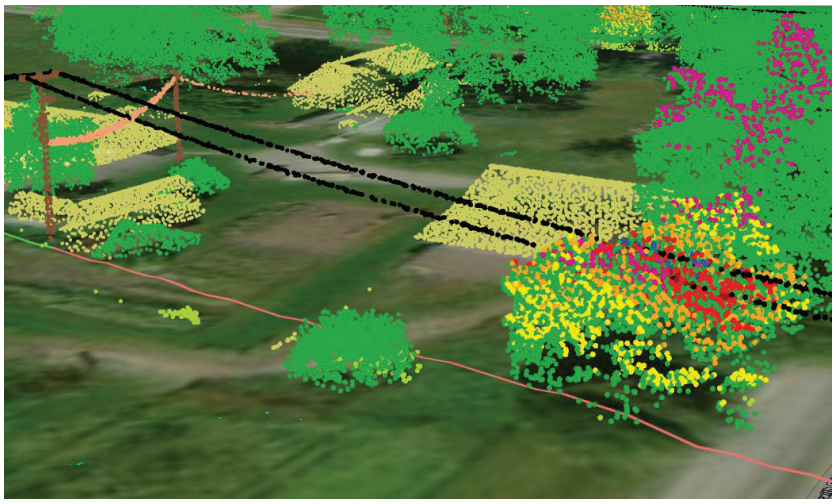
[19] Percent of customers interrupted by unplanned outages in 2025 with cause code of Trees or Trees - Outside ROW.

considerations; and

- Evaluating spans with high-risk scores on circuits that are mid-cycle for mid-cycle clearing.

Figure 22

3D LiDAR Map Example



For example, Figure 22 shows a span on an LVD circuit at the end of its five-year cycle. LiDAR points are classified utilizing a color key: brown points represent a pole, black points represent the primary conductors, red/yellow/green points represent identified vegetation grow-in present on this span by distance, pink points represent vegetation with fall-in potential, and blue points represent vegetation overhanging the conductors.

The Company is proposing to continue capturing LiDAR in this targeted area to enable opportunities to evaluate change detection and measure the impacts of line clearing intervention in elevated risk areas on an annual basis. LiDAR creates the opportunity for the Company to utilize a new type of data in its Line Clearing Program on a small scale first while it strengthens its abilities and evaluates expansion opportunities in the future.

Opportunities to Evaluate

The Company will continue to evaluate additional ways to adjust line clearing practices to mitigate wildfire risk by benchmarking with peer utilities and collaborating with organizations such as EPRI to identify new technologies and best practices for wildfire risk mitigation. One opportunity for further evaluation is an expanded scope of hazard tree removal in the elevated risk areas.

Hazard trees (dead, dying, or mechanically stressed trees) within 20 feet of the edge of the ROW are removed when the property owner does not object. Currently, hazard trees are identified and removed as part of the standard clearing cycle process in the Line Clearing Program.

In elevated wildfire risk areas, wildfire risk could be further mitigated by expanding the scope of hazard tree removal through either increased frequency or increased distance from pole centerline:

- Mid-cycle hazard tree removal mitigation would identify hazard trees mid-cycle and remove

them; this will help mitigate the risk of hazard trees falling on lines in-between cycle clearing.

- Expanding the distance from centerline hazard trees are identified and removed would help mitigate the risk of hazard trees further away falling on lines.

Figure 23 below illustrates the risk of trees outside of the standard 30' ROW corridor.

Figure 23

Out of ROW Tree Failure on LVD Three Phase



The Company is proposing a focus on achieving its enhanced line clearing program strategy by the end of the 2030-2031 test period, as outlined in the Reliability Roadmap, which includes reduced cycles across the electric service territory and a scope of more aggressive line clearing, before adding additional line clearing tactics such as mid-cycle hazard tree removal.

Stakeholder Engagement

Industry. Through benchmarking with utilities located in the Eastern, Southeastern, Midwest, Mountain West and Pacific West, Consumers Energy identified best practices for wildfire risk mitigation. These relationships will be leveraged as the Company continues to build out and mature this wildfire risk mitigation plan. Consumers Energy is also engaged with industry groups including EEI and EPRI, which provide knowledge sharing opportunities through working groups and summits.

Agencies. Communication and coordination with local and state emergency agencies and first responders is essential to the success of wildfire risk mitigation. Consumers Energy coordinates with these agencies as part of the Company's standard emergency response activities and will broaden that engagement as wildfire risk-specific mitigation activities are operationalized.

In November 2025, the Company met with the USFS and the Michigan DNR to conduct a

downed-wire awareness training session and to review the USFS incident command structure and coordinated response protocols.

In April 2026, the Company participated in a wildfire preparedness meeting in Mio, MI with the USFS for the Huron Zone, which is identified as one of the most at-risk areas of the Company's electric grid system. Participants included representatives from the USFS, Michigan DNR, local fire departments, the Michigan State Police, and the local Road Commission.

Feedback from these engagements indicated strong appreciation for the Company's proactive participation and focus on wildfire preparedness. These collaborative efforts strengthen interagency coordination and enhance wildfire response readiness across Michigan, supporting the effectiveness of the Company's wildfire risk mitigation plan.

There may be additional opportunities in the future to engage with local and state agencies on public education and awareness, wildfire risk mitigation planning, wildfire risk mitigation activities, wildfire emergency preparedness, and wildfire emergency response.

Public. The Company will use existing corporate communications and community affairs channels to engage the public on the wildfire risk mitigation activities and investments in this plan. As the plan matures, additional engagement will be considered to increase education and awareness around times of elevated wildfire risk.

Conclusion

This wildfire risk mitigation plan is designed to protect public safety, physical structures, the environment, and the electric distribution system. By proactively identifying risks, implementing mitigation measures, maintaining readiness, and collaborating with relevant state and local agencies, Consumers Energy can reduce the impact of wildfires on our operations and maintain a resilient electrical grid for the state of Michigan.

As part of this approach, the Company will determine best practices and gain additional knowledge around the cost and effectiveness of the wildfire risk mitigation tactics implemented which are outlined in this plan. Consumers Energy will continue to evaluate investment plans based on skills and efficiencies learned during the test year and may propose a more aggressive future workplan to mitigate wildfire risk.

Regular reviews and updates to this plan will be made to ensure it remains consistent with industry and government recommendations and standards which are still evolving.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Advanced Metering Infrastructure Metrics and Elements

Case No.: U-22070
Exhibit No.: A-100 (EMD-16)
Page: 1 of 1
Witness: EMDuke
Date: June 2026

Line No.	(a) Metric	(b) Value	(c) Result	(d) Notes
1	**Consecutive estimates**	**Efficiencies, Cost Savings**		
2	2025 AMI electric meter read rate		99.80%	
3	Consecutive estimates as of December 31, 2025		471	Customers with more than 2 electric consecutive estimates
4	**Demand Response (DR)**	**Cost Savings**		**Reduces capacity needs**
5	Air Conditioning Peak Cycling (ACPC) MW enrollments		50.4	As of November 30, 2025
6	Dynamic Peak Pricing (DPP) MW enrollments		44.4	As of November 30, 2025
7	Smart Termostat Program (STP) MW enrollments		59.4	As of November 30, 2025
8	2025 ACPC maximum MW demand reduction achieved		27.3	
9	2025 DPP maximum MW demand reduction achieved		0.0	No events completed in 2025
10	2025 STP maximum MW demand reduction achieved		52.8	
11	Summer PY2025 DR awarded as Load Modifying Resources		555.8 MW	
12	75% of PY2025 MISO Cost of New Entry (CONE)		$98,197	PY2025/26 CONE of $130,930/MW times 75%
13	Value of DR in Reducing Capacity Needs		$54,577,893	Line 11 times Line 12
14	**Conservation voltage reduction (CVR)**	**Cost Savings**		**Reduces capacity needs**
15	Number of CVR enabled circuits as of December 31, 2025		514	
16	Number of circuits that are planned for CVR enablement		900	Plan to enable 85 circuits per year until 900 are enablec
17	Percentage of total planned circuits enabled		57%	Line 15 divided by Line 16
18	2025 Cumulative peak MW reduction from CVR		53.0 MW	
19	75% of PY2025 MISO Cost of New Entry (CONE)		$98,197	PY2025/26 CONE of $130,930/MW times 75%
20	Value of CVR in Reducing Capacity Needs		$5,204,441	Line 18 times Line 19
21	**Leverage data to target reliability investments**	**Reliability**		
22	2025 System Average Interruption Duration Index (SAIDI)		163.48	Excluding major event days
23	2025 System Average Interruption Frequency Index (SAIFI)		0.875	Excluding major event days
24	Outage minutes avoided due to AMI meters			CAIDI = Customer Average Interruption Duration Index
25	2025 CAIDI excluding MEDs for AMI notification only		145	MED = Major Event Days
26	2025 CAIDI excluding MEDs for customer notification only		875	
27	2025 CAIDI excluding MEDs for AMI and customer notification		373	
28	2025 Momentary Average Interruption Frequency Index (MAIFI)		3.36	
29	**Distributed Energy Resources (DERs)**	**DER Deployment**		
30	Energy exported to the grid from DERs		64,326 MWh	
31	**Qualitative elements**	**Varies**		
32	Support Load Flow Tool Upgrade	DER Deployment		Support automating data modeling and forecasting of grid impacts from distributed energy resources (DERs) and electric vehicles (EVs) to provide planning departments with visibility of present and future capacity constraints on the LVD system as DER and EV penetration increases
33	Assess SAIDI in Environmental Justice (EJ) communities	Reliability		Measuring SAIDI in specific EJ communities would allow the Company to better target reliability investments

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Distribution
Summary of Actual & Projected Capital Expenditures per Rate Case Filing Requirements Attachment 11
($000)

Case No.: U-22070
Exhibit No.: A-101 (EMD-17)
Page: 1 of 1
Witness: EMDuke
Date: June 2026

Line No.	(a) Program Description	(b) Historical Test Year 2025 Actual	(c) Last Rate Case Approved Spending Plan Case No. U-21870 12 mos. Ending 4/30/2027	(d) Last Rate Case Actual Spending Case No. U-21870 12 mos. Ending 4/30/2027	(e) Variation Percentage [1]	(f) Location of Testimony Regarding Significant Var [1] (>10%)	(g) Current Case Projection 12 mos. Ending 4/30/2028
		Capital Expenditures					
1	New Business Program	314,050	347,888	n/a	n/a	n/a	316,079
2	Reliability Program	428,469	545,241	n/a	n/a	n/a	668,725
3	Capacity Program	109,331	88,090	n/a	n/a	n/a	143,608
4	Demand Failures Program	318,126	184,851	n/a	n/a	n/a	173,040
5	Asset Relocation Program	103,876	90,393	n/a	n/a	n/a	150,570
6	Electric Other Program	5,788	8,468				8,548
7	**Total Capital**	1,279,640	1,264,931	-			1,460,571

Footnote:

[1] The projected test year in Case No. U-21870 has not transpired as of the date of this filing

EXHIBIT A-102 (EMD-18)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Comparison of Distribution Plan and Instant Case for Part III Requirement #170

Case No.: U-22070
Exhibit No.: A-103 (EMD-19)
Page: 1 of 1
Witness: EMDuke
Date: June 2026

		Proposed Capital Spending Amount ($) from Distribution Plan*			Actual/Requested Capital in Instant Rate Case ($)		
Line No.	Program or Project Name in Instant Case	Proposed Amount for Historic Test Year ($)	Proposed Amount for Bridge Period ($)	Proposed Amount for Projected Test Year ($)	Actual Historic Test Year ($)	Requested Bridge Period ($)	Requested Projected Test Year ($)
1	LVD Lines New Business (sub-program)	*New Business not itemized in Reliability Roadmap*			114,568,000	155,516,000	121,618,000
2	Demand Failures (program, excluding Meter Purchases)	*Demand Failiures not itemized in Reliability Roadmap*			290,746,000	248,520,000	156,197,000
3	LVD Asset Relocations (sub-program)	*Asset Relocations not itemized in Reliability Roadmap*			88,913,000	168,109,000	131,401,000
4	Targeted Circuit Improvements (investment category)	N/A**	211,333,333	178,300,000	66,659,512	129,836,000	93,395,000
5	ATR Loops (investment category)	N/A**	28,033,333	15,400,000	25,100,000	26,029,000	17,668,000
6	LVD Pole Replacements (investment category)	N/A**	162,333,333	190,000,000	7,613,230	150,973,000	125,000,000
7	Circuit Exit Projects (investment category)	*Not itemized in Reliability Roadmap*			3,574,045	4,090,000	3,189,000
8	LVD right-of-way (investment category)	*Not itemized in Reliability Roadmap*			7,587,498	13,333,000	11,373,000
9	LVD Repetitive Outages (sub-program)	*Not itemized in Reliability Roadmap*			12,903,000	33,215,000	27,493,000
10	Imminent Rehabilitation (investment category)	*Not itemized in Reliability Roadmap*			13,068,529	13,475,000	5,299,000
11	Subsurface Transformers (investment category)	N/A**	2,766,667	1,200,000	N/A***	1,940,000	-
12	Modem Replacements (investment category)	*Not itemized in Reliability Roadmap*			3,905,157	2,998,000	2,998,000
13	Meter Voltage Anomalies (investment category)	N/A**	17,033,333	8,366,667	N/A***	15,392,000	11,658,000
14	Resiliency (sub-program)	N/A**	87,800,000	163,000,000	41,767,000	55,030,000	78,751,000
15	LVD Lines Capacity (sub-program)	N/A**	61,666,667	53,000,000	17,876,000	39,861,000	53,485,000
16	LVD New Business Capacity (sub-program)	*Not itemized in Reliability Roadmap*			32,679,000	40,156,000	30,339,000
17	CVR (sub-program)	*Not itemized in Reliability Roadmap*			5,159,000	3,868,000	2,429,000
18	LVD Metering (sub-program)	*Metering dollars not specified in Reliability Roadmap*			27,380,000	28,580,000	16,843,000
19	LVD Transformers (sub-program)	*Transformers dollars not specified in Reliability Roadmap*			152,452,000	187,718,000	138,661,000
20	Electric Other (program)	*Not itemized in Reliability Roadmap*			5,788,000	9,831,000	8,548,000
21	HVD Line Rebuilds (investment category)	N/A**	50,200,000	50,100,000	18,257,970	59,951,000	41,365,000
22	HVD Pole Top Rehab miles and assemblies (investment category)	N/A**	15,466,667	16,166,667	15,124,928	9,753,000	13,303,000
23	HVD Pole Replacements (investment category)	N/A**	43,666,667	22,700,000	53,015,880	40,966,000	25,753,000
24	HVD Switches (investment category)	*Not itemized in Reliability Roadmap*			3,649,543	8,468,000	12,661,000
25	HVD Line Sensors (investment category)	*Not itemized in Reliability Roadmap*			838,268	2,374,000	2,374,000
26	HVD Lines ROW (investment category)	*Not itemized in Reliability Roadmap*			3,112,109	7,331,000	8,332,000
27	HVD Substations Reliability (sub-program)	N/A**	51,533,333	39,700,000	23,161,000	25,729,000	46,180,000
28	Transformer Bank Replacements and Substation Rebuilds (sub-program)	N/A**	48,533,333	37,000,000	22,285,000	26,605,000	37,155,000
29	LVD Substations Reliability (sub-program)****	N/A**			43,773,000	65,664,000	42,880,000
30	LVD Substations Rehabilitation (sub-program)****	N/A**	97,380,000	123,050,000	22,174,000	31,000,000	31,328,000
31	Metro Reliability (sub-program)#	N/A**			4,629,000	5,330,000	4,131,000
32	Metro Rehabilitation (sub-program)#	N/A**	13,093,333	9,700,000	4,512,000	2,953,000	5,495,000
33	System Protection (sub-program)	N/A**	5,820,000	4,363,333	5,244,000	5,939,000	4,672,000
34	HVD Lines and Substations Capacity (sub-program)	N/A**	41,666,667	35,000,000	20,006,000	41,904,000	34,956,000
35	LVD Substations Capacity (sub-program)	*Not itemized in Reliability Roadmap*			33,612,000	18,885,000	22,399,000
36	HVD New Business (sub-program)	N/A**	60,233,333	23,366,667	40,821,000	43,005,000	48,064,000
37	Metro New Business (sub-program)##	N/A**			6,209,000	9,223,000	7,737,000
38	Metro Relocations (sub-program)##	N/A**	33,933,333	26,000,000	14,353,000	26,201,000	18,270,000
39	HVD Asset Relocations (sub-program)	*Asset Relocations not itemized in Reliability Roadmap*			610,000	1,198,000	899,000

* 'Distribution Plan' refers to Reliability Roadmap as amended for Case No. U-21870

** Historic years not shown in Reliability Roadmap

*** New sub-program

****Reliability Roadmap presents LVD Substations Reliability and Resiliency in a single investment plan

#Reliability Roadmap presents Metro Reliability and Rehabilitation in a single investment plan

##Reliability Roadmap presents Metro New Business and Reloctions in a single investment plan

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

MATTHEW J. FOSTER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Summary of Projected Electric Corporate and Other O&M Expense
($000)

Case No.: U-22070
Exhibit No.: A-104 (MJF-1)
Page: 1 of 2
Witness: MJFoster
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
1	**Corporate Services Expense**	**$ 24,280**	**$ 25,796**
	Labor	17,145	18,216
	Material	-	-
	Contractor	5,004	5,317
	Non-Labor Overhead	-	-
	Non-Labor Other	2,131	2,263
2	**Insurance Expense**	**14,143**	**15,266**
	Labor	-	-
	Material	-	-
	Contractor	-	-
	Non-Labor Overhead	-	-
	Non-Labor Other	14,143	15,266
3	**Uncollectible Expense**	**21,475**	**21,561**
	Labor	-	-
	Material	-	-
	Contractor	-	-
	Non-Labor Overhead	-	-
	Non-Labor Other	21,475	21,561
4	**Injuries & Damages Expense**	**5,431**	**5,703**
	Labor	462	490
	Material	-	-
	Contractor	-	-
	Non-Labor Overhead	-	-
	Non-Labor Other	4,970	5,213
5	**Digitization of Company Records Expense**	**-**	**1,260**
	Labor	-	-
	Material	-	-
	Contractor	-	1,260
	Non-Labor Overhead	-	-
	Non-Labor Other	-	-
6	**Total O&M Expenses**	**$ 65,329**	**$ 69,585**
	Labor	17,607	18,706
	Material	-	-
	Contractor	5,004	6,577
	Non-Labor Overhead	-	-
	Non-Labor Other	42,718	44,302

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Summary of Projected Electric Corporate and Other O&M Expense
($000)

Case No.: U-22070
Exhibit No.: A-104 (MJF-1)
Page: 2 of 2
Witness: MJFoster
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Actual 12 Mos Ending 12/31/2025	(d) Inflation Applied to Projected Test Year	(e) Scope/ Cost Increases Net of Productivity Gains	(f) Projected O&M 12 Mos Ending 4/30/2028
				(c) * Compounded Inflation Rate		(c) + (d) + (e)
1	Corporate Services Expense	Exhibit A-105 (MJF-2)	$ 24,280	$ 1,516	$ (0)	$ 25,796
2	Insurance Expense	Exhibit A-106 (MJF-3)	14,143	883	240	15,266
3	Uncollectible Expense	Exhibit A-107 (MJF-4)	21,475	1,341	(1,256)	21,561
4	Injuries & Damages Expense	Exhibit A-108 (MJF-5)	5,431	339	(68)	5,703
5	Digitizing Company Records Expense	Not Applicable	-	-	1,260	1,260
5	Total O&M Expenses		65,329	4,080	176	69,585

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Projected Corporate Services O&M Expense
for the Years 2025, and the 12 Months Ending April 30,2028
($000)

Case No.: U-22070
Exhibit No.: A-105 (MJF-2)
Page: 1 of 1
Witness: MJFoster
Date: June 2026

Line No.	Description	2025 Labor Actual	2025 Non-Labor Actual	Total 2025 Actual	12 Mos Ending 4/30/28 Lbr Inflation Projected	12 Mos Ending 4/30/28 N-Lbr Inflation Projected	Total Inflation Projected	Other Adjustment	12 Mos Ending 4/30/2028 Total Projected
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1					(b) * inflation	(c) * Inflation	(d) + (e) + (f)		(g) + (h)
2	Sustainability & External Affairs	$ 3,041	$ 1,049	$ 4,090	$ 190	$ 66	$ 4,346	$ -	$ 4,346
3	Legal, Ethics, Regulatory, and Risk	8,289	3,500	11,789	518	219	12,526	-	12,526
4	People & Culture and Learning and Development	8,885	2,170	11,055	555	136	11,746	-	11,746
5	Finance and Shared Services	12,903	5,254	18,157	806	328	19,291	-	19,291
6	General Activities	(1,435)	(5,005)	(6,441)	(90)	(313)	(6,843)	-	(6,843)
7	Total	$ 31,684	$ 6,967	$ 38,652	$ 1,979	$ 435	$ 41,066	$ -	$ 41,066
8	Less: EICP	14,500	-	14,500	906	-	15,405	-	$ 15,405
9	Less: Transfers Out	-	-	-	-	-	-	-	-
10	Total Corporate Service Departments	$ 17,184	$ 6,967	$ 24,152	$ 1,073	$ 435	$ 25,660	$ -	$ 25,660
11	Administration & Other-Electric Portion	-	820	820	-	51	871	-	$ 871
12	**Total Corporate Services**	$ 17,184	$ 7,787	$ 24,972	$ 1,073	$ 486	$ 26,531	$ -	$ 26,531
	Normalizations								
13	N/A	-	-	-	-	-	-	-	$ -
14	**Total Normalizations**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Less Giving and Communications								
16	Corporate Giving & Comm. Salaries per WP-HLP-16, line 1 and 8	(39)		(39)	(2)	-	(42)	-	(42)
17	Dues, Donations & Lobbying Expenses per WP-HLP-18		(653)	(653)	-	(41)	(693)	-	(693)
18	**Total Giving and Communications**	$ (39)	$ (653)	$ (692)	$ (2)	$ (41)	$ (735)	$ -	$ (735)
19	**TOTAL ADJUSTED CORPORATE SERVICES EXPENSE**	$ 17,145	$ 7,135	**$ 24,280**	$ 1,071	$ 446	$ 25,796	$ -	**$ 25,796**

		12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
20	Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
	Number of months in the period	12	12	4	
	Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Insurance Expense
for the Years 2021 through the 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-106 (MJF-3)
Page: 1 of 1
Witness: MJFoster
Date: June 2026

Line No.	(a) Insurance Description	(b) 2021 Actual	(c) 2022 Actual	(d) 2023 Actual	(e) 2024 Actual	(f) 2025 Actual	(g) Compound Annual Growth Rate 2021-2025	(h) Projected O&M 12 Months Ending 4/30/2028
1	Property Insurance	$ 7,974	$ 8,603	$ 8,837	$ 7,968	$ 7,226	-2.432%	$ 6,739
2	Liability Insurance	8,312	8,637	9,206	10,492	12,058	9.747%	15,694
3	Other	8	9	10	11	10	5.192%	11
4	Total Premiums	**$ 16,294**	**$ 17,249**	**$ 18,053**	**$ 18,471**	**$ 19,294**		**$ 22,444**
5	Distributions (Refunds)	(8,610)	(12,470)	(3,520)	(6,141)	(5,151)		(7,178)
6	Electric Insurance Expense	**$ 7,684**	**$ 4,779**	**$ 14,533**	**$ 12,330**	**$ 14,143**		**$ 15,266**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Uncollectible Accounts Expense
for the Years 2025, and the 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-107 (MJF-4)
Page: 1 of 2
Witness: MJFoster
Date: June 2026

Line No.	(a) Description	(b) 2025 Actual	(c) 12 Months Ending 4/30/2028 Projected
1	Uncollectible Accounts Expense	$ 21,475	**$ 21,561** [1]

[1] Exhibit A-107 (MJF-4) Page 2, line 9, column (e) (3-Year Average BDLR 2023-25)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Uncollectible Accounts Expense
for the Years 2021 Through the 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-107 (MJF-4)
Page: 2 of 2
Witness: MJFoster
Date: June 2026

Line No.	(a) Year	(b) Gross Charge-Offs	(c) Less Recoveries	(d) Net Write-Offs	(e) Total Electric Service Revenue MPSC P-521 P. 304.1 col (c) + P. 305 col (c)	(f) BDLR col (d) / col (e)
1	2021	26,335	10,844	15,491	4,681,931	0.331%
2	2022	27,543	8,726	18,817	4,737,236	0.397%
3	2023	29,146	7,478	21,668	4,709,798	0.460%
4	2024	25,816	7,742	18,074	4,934,300	0.366%
5	2025	29,566	8,090	21,475	5,467,613	0.393%
6	3-Year Average 2023 - 2025	$ 28,176	$ 7,770	$ 20,406	$ 5,037,237	0.405%
7	Test Year Total Company Electric Revenues and Deliveries Exhibit A-15 (EMB-3), Schedule E-2, Page 1 of 1 Row 24, Column (j) - Row 24, Column (c)				$ 5,322,401	
8	3-Year Average 2023 - 2025				0.405%	
9	Test Year Total Uncollectible Accounts Expense				**$ 21,561**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Injuries & Damages Expense
for the Years 2021 Through the 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-108 (MJF-5)
Page: 1 of 1
Witness: MJFoster
Date: June 2026

Line No.	(a) Program Description		(b) 2021 Actual	(c) 2022 Actual	(d) 2023 Actual	(e) 2024 Actual	(f) 2025 Actual	(g) 12 Mos Ending 4/30/2028 Projected
1	Electric Injuries & Damages	[1]	$ 2,694	$ 5,567	$ 4,311	$ 6,619	$ 3,597	$ 4,558
2	Internal Legal Costs	[2]	412	424	474	441	435	437
3	Workers' Compensation	[3]	401	661	462	617	1,399	708
4	Total Electric Injuries & Damages		**$ 3,507**	**$ 6,652**	**$ 5,246**	**$ 7,677**	**$ 5,431**	**$ 5,703**

[1] Electric Injuries & Damages costs are 2021 - 2025 actual expense. Test Year Ending 4/30/2028 used a 5-year average (2021 - 2025).

[2] Electric Internal Legal costs are 2021 - 2025 actual expense. Test Year Ending 4/30/2028 used a 5-year average (2021 - 2025).

[3] Electric Workers' Compensation costs are 2021 - 2025 actual expense. Test Year Ending 4/30/2028 used a 5-year average (2021 - 2025).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Corporate Membership Dues
for the Year Ended December 31, 2025

Case No.: U-22070
Exhibit No.: A-109 (MJF-6)
Page: 1 of 1
Witness: MJFoster
Date: June 2026

Line No.	(a) Organization	(b) Description	(c) Customer Benefits	(d) Membership Costs	(e) Membership Costs included for recovery
1	Detroit Regional Chamber of Commerce (DRC)	The DRC serves as the primary voice for business across the 11-county Southeast Michigan region. The DRC core function is to foster a "business-friendly climate" and drive regional economic growth through four strategic pillars: Economic Development, Regional Collaboration, Education Reform, and Member Value.	Chamber of Commerce memberships enable the Company to connect with business customers, strengthen community relationships, and support economic growth across Michigan.	$ 5,653	$ 3,543
2	Jackson County Chamber of Commerce	The Jackson County Chamber is the leading driver and advocate for dynamic business and economic development in Jackson County. Creating a vibrant, inclusive community, through meaningful partnerships, intentional connections and engagement.	Chamber of Commerce memberships enable the Company to connect with business customers, strengthen community relationships, and support economic growth across Jackson County.	3,150	2,100
3	Keystone Policy Center	Keystone Policy Center is a trusted non-profit organization founded in 1975 to drive actionable, shared solutions to contentious policy challenges. Keystone is recognized by public, private, and civic-sector leaders throughout the United States for independent, collaborative problem-solving approaches that offer a proven blueprint for progress and collective impact. The Keystone Energy Board is a longstanding forum for energy sector leaders to learn about and discuss timely issues, examining the linkages among energy, environmental and economic policies. The Energy Board is comprised of about 50 individuals representing different perspectives on energy policy; our members bring expertise from industry, technology, environmental and consumer advocacy, and state and federal government.	The Keystone Policy Center values to Consumers Energy customers include networking, utility benchmarking, best practices, and research with a focus on environmental issues, renewable energy standards, load growth from data centers, and grid reliability.	12,600	8,400
4	Michigan Electric and Gas Association (MEGA)	MEGA works with the Michigan legislature, federal and state regulatory agencies, and the entire Michigan energy industry to ensure safe, reliable, and affordable electric utility service.	MEGA delivers value to Consumers Energy customers by engaging with the Michigan Legislature, federal and state regulatory agencies, and the broader Michigan energy industry to support safe, reliable, and affordable electric service and support for low-income programs.	15,750	10,501
5	Edison Electric Institute (EEI)	EEI provides strategic business intelligence, and essential conferences and forums. The EEI facilitates collaboration regarding emerging issues facing the industry. The EEI also provides a forum to ask industry related questions to other utilities and provides invaluable resource information about the utility industry and other issues.	EEI provides value to Consumers Energy customers through Mutual Assistance coordination to quickly secure resources for storm restoration. The electric utility industry has no other mutual assistance structure. Other benefits from the EEI membership include utility benchmarking and best practices on subjects such IT & Security, grid modernization, economic development, suppply chain, renewable generation, and other utility functions that helps the Company understand its performance to utility peers. EEI facilitates sharing of best practices and is an invaluable resource of information that can help the Company better serve our customers.	1,301,133	721,696
6	Association of Edison Illuminating Companies (AEIC)	AEIC is the electric utility industry's longest-serving and preeminent association, where leaders from 185 member companies work together to share knowledge that is essential to achieving operational excellence and grid modernization. AEIC brings together the electric utility industry's leading operations experts to rise to challenges, accelerate opportunities, and achieve excellence in all aspects of generation, transmission, distribution, and storage of electric power for the benefit of its members, the industry at large, and consumers.	AEIC provides value to Consumers Energy customers by providing an affordable option to access information on best practice, research, and the exchange of technical resources on topics such as grid modernization, grid reliability, clean energy, safety, energy efficiency, generation, and storage of electric power.	27,228	18,153

Schedule: B-5.3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Corporate Capital
($000)

Case No.: U-22070
Exhibit No.: A-12 (MJF-7)
Schedule: B-5.3
Page: 1 of 2
Witness: MJFoster
Date: June 2026

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Period 12 Mos Ended 12/31/2026	(d) Projected Bridge Period 4 Mos Ending 4/30/2027	(e) Projected Bridge Period 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
1	Corporate Capital	788	810	277	1,087	837

Line No	Description	Projected 4 Mos Ending 4/30/2026	Projected 12 Mos Ending 4/30/2027	Projected 12 Mos Ending 4/30/2028	Projected 28 Mos Ending 4/30/2028
2	Corporate Capital	270	817	837	1,924

Schedule: B-5.3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Corporate Capital
($000)

Case No.: U-22070
Exhibit No.: A-12 (MJF-7)
Schedule: B-5.3
Page: 2 of 2
Witness: MJFoster
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2025	12 Mos Ending 12/31/2026	4 Mos Ending 4/30/2027	16 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028
1	Corporate Capital	788	810	277	1,087	837
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	219	226	77	303	233
	Contractor	568	585	200	784	604
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0

		Projected			
		4 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028	28 Mos Ending 4/30/2028
2	Corporate Capital	270	817	837	1,924
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	75	228	233	536
	Contractor	195	589	604	1,388
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

ALEX M. GAST

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Customer Experience & Growth
($000)

Case No.: U-22070
Exhibit No.: A-12 (AMG-1)
Schedule: B-5.7
Page: 1 of 3
Witness: AMGast
Date: June 2026

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Period 12 Mos Ended 12/31/2026	(d) Projected Bridge Period 4 Mos Ending 4/30/2027	(e) Projected Bridge Period 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
1	Customer Billing	110	0	0	0	0
2	Credit & Assistance	16	845	170	1,015	510
3	Demand Response (C&I)	406	362	40	402	120
4	Demand Response (Res)	(903)	55	20	75	60
5	PowerMiDrive	1,317	589	0	589	0
6	PowerMiFleet	673	4	0	4	0
7	Total CX&G Capital	1,619	1,856	230	2,086	690

		Projected 4 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028	28 Mos Ending 4/30/2028
8	Customer Billing	4	0	0	4
9	Credit & Assistance	168	843	510	1,522
10	Demand Response (C&I)	32	370	120	522
11	Demand Response (Res)	15	60	60	135
11	PowerMiDrive	189	400	0	589
12	PowerMiFleet	4	0	0	4
13	Total CX&G Capital	412	1,673	690	2,776

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Customer Experience & Growth
($000)

Case No.: U-22070
Exhibit No.: A-12 (AMG-1)
Schedule: B-5.7
Page: 2 of 3
Witness: AMGast
Date: June 2026

Line No	Description	Historical Year 12 Mos Ended 12/31/2025	Projected Bridge Year 12 Mos Ending 12/31/2026	Projected Bridge Year 4 Mos Ending 4/30/2027	Projected Bridge Year 16 Mos Ending 4/30/2027	Projected Test Year 12 Mos Ending 4/30/2028
	(a)	(b)	(c)	(d)	(e)	(f)
1	Customer Billing	110	0	0	0	0
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	1	0	0	0	0
	Contractor	110	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0
2	Credit & Assistance	16	845	170	1,015	510
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	16	4	0	4	0
	Contractor	0	842	170	1,012	510
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0
3	Total Customer Experience & Growth Capital	126	845	170	1,015	510
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	16	4	0	4	0
	Contractor	110	842	170	1,012	510
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Customer Experience & Growth
($000)

Case No.: U-22070
Exhibit No.: A-12 (AMG-1)
Schedule: B-5.7
Page: 3 of 3
Witness: AMGast
Date: June 2026

	(a)	(b)	(c)	(d)	(e)
		Projected			
		4 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028	28 Mos Ending 4/30/2028
4	Customer Billing	4	0	0	4
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	4	0	0	4
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
5	Credit & Assistance	168	843	510	1,522
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	0	0
	Contractor	168	843	510	1,522
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
6	Total Customer Experience & Growth Capital	172	843	510	1,525
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	4	0	0	4
	Contractor	168	843	510	1,522
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
CX&G O&M
($000)

Case No.: U-22070
Exhibit No.: A-110 (AMG-2)
Page: 1 of 4
Witness: AMGast
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
1	Billing & Payment	10,882	12,640
	Labor	2,526	2,913
	Material	758	753
	Contractor	1,632	1,764
	Non-Labor Overhead	0	0
	Non-Labor Other	5,966	7,209
2	Customer Interactions	22,524	28,137
	Labor	15,737	20,172
	Material	43	50
	Contractor	5,391	6,125
	Non-Labor Overhead	0	0
	Non-Labor Other	1,354	1,791
3	Total CX&G O&M Expenses	33,407	40,777
	Labor	18,263	23,085
	Material	801	803
	Contractor	7,023	7,889
	Non-Labor Overhead	0	0
	Non-Labor Other	7,320	9,000

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
CX&G O&M
($000)

Case No.: U-22070
Exhibit No.: A-110 (AMG-2)
Page: 2 of 4
Witness: AMGast
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
1	Customer Billing	9,367	11,188
	Labor	2,044	2,461
	Material	758	753
	Contractor	694	785
	Non-Labor Overhead	0	0
	Non-Labor Other	5,872	7,189
2	Customer Payment Programs	1,515	1,452
	Labor	482	452
	Material	0	0
	Contractor	939	979
	Non-Labor Overhead	0	0
	Non-Labor Other	95	20
3	Total Billing & Payment O&M Expenses	10,882	12,640
	Labor	2,526	2,913
	Material	758	753
	Contractor	1,632	1,764
	Non-Labor Overhead	0	0
	Non-Labor Other	5,966	7,209

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
CX&G O&M
($000)

Case No.: U-22070
Exhibit No.: A-110 (AMG-2)
Page: 3 of 4
Witness: AMGast
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
1	Analytics & Outreach	2,564	4,853
	Labor	1,672	2,817
	Material	1	0
	Contractor	757	1,815
	Non-Labor Overhead	0	0
	Non-Labor Other	134	220
2	Business Customer Care	2,171	3,712
	Labor	1,620	2,835
	Material	1	0
	Contractor	488	333
	Non-Labor Overhead	0	0
	Non-Labor Other	62	543
3	Credit & Assistance	2,790	2,937
	Labor	1,498	1,920
	Material	33	50
	Contractor	955	871
	Non-Labor Overhead	0	0
	Non-Labor Other	304	96
4	Customer Contact Center	14,070	13,881
	Labor	10,319	10,561
	Material	8	0
	Contractor	2,957	2,603
	Non-Labor Overhead	0	0
	Non-Labor Other	785	718
5	Digital Customer Operations	930	2,754
	Labor	627	2,039
	Material	0	0
	Contractor	234	503
	Non-Labor Overhead	0	0
	Non-Labor Other	69	213
6	Total Customer Interactions O&M Expenses	22,524	28,137
	Labor	15,737	20,172
	Material	43	50
	Contractor	5,391	6,125
	Non-Labor Overhead	0	0
	Non-Labor Other	1,354	1,791

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
CX&G O&M
($000)

Case No.: U-22070
Exhibit No.: A-110 (AMG-2)
Page: 4 of 4
Witness: AMGast
Date: June 2026

Line No.	Description	(a) Actual 12 Mos Ending 12/31/2025	(b) Inflation Applied to Projected Test Year (b) * Compounded Inflation Rate	(c) Scope/ Cost Increases Net of Productivity Gains	(d) Projected O&M 12 Mos Ending 4/30/2028 (b) + (c) + (d)
1	Billing & Payment	10,882	680	1,078	$ 12,640
2	Customer Interactions	22,524	1,407	4,206	28,137
3	Total CX&G O&M Expenses	33,407	2,087	5,284	40,777

Notes

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

Schedule B-5.8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
For Demand Response C&I and Residential Programs
($000)

Case No.: U-22070
Exhibit No.: A-12 (AMG-3)
Schedule: B-5.8
Page: 1 of 2
Witness: AMGast
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2025	12 Mos Ending 12/31/2026	4 Mos Ending 4/30/2027	16 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028
1	Demand Response (C&I)	406	362	40	402	120
	Labor	146	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	64	362	40	402	120
	Contractor	185	0	0	0	0
	Non-Labor Overhead	4	0	0	0	0
	Non-Labor Other	7	0	0	0	0
	Contingency	0	0	0	0	0
2	Demand Response (Res)	(903)	55	20	75	60
	Labor	2	0	0	0	0
	Capitalized E&S	4	0	0	0	0
	Materials	(865)	55	20	75	60
	Contractor	(10)	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	(34)	0	0	0	0
	Contingency	0	0	0	0	0
3	Total Demand Response Capital	(497)	417	60	477	180
	Labor	148	0	0	0	0
	Capitalized E&S	4	0	0	0	0
	Materials	(801)	417	60	477	180
	Contractor	176	0	0	0	0
	Non-Labor Overhead	4	0	0	0	0
	Non-Labor Other	(27)	0	0	0	0
	Contingency	0	0	0	0	0

Schedule B-5.8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
For Demand Response C&I and Residential Programs
($000)

Case No.: U-22070
Exhibit No.: A-12 (AMG-3)
Schedule: B-5.8
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	(a)	(b)	(c)	(d)	(e)
		Projected			
		4 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028	28 Mos Ending 4/30/2028
4	Demand Response (C&I)	32	370	120	522
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	32	370	120	522
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
5	Demand Response (Res)	15.095	60.000	60.000	135.095
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	15	60	60	135
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
6	Total Demand Response Capital	47	430	180	657
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	47	430	180	657
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Demand Response
($000)

Case No.: U-22070
Exhibit No.: A-111 (AMG-4)
Page: 1 of 2
Witness: AMGast
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
1	Demand Response (C&I)	17,511	20,280
	Labor	3,912	3,333
	Material	3	0
	Contractor	5,078	4,694
	Non-Labor Overhead	0	0
	Non-Labor Other	8,518	12,253
2	Demand Response (Res)	11,894	13,348
	Labor	2,682	2,354
	Material	2	0
	Contractor	5,780	5,022
	Non-Labor Overhead	0	0
	Non-Labor Other	3,430	5,972
3	Total Demand Response O&M Expenses	29,406	33,628
	Labor	6,595	5,687
	Material	5	0
	Contractor	10,858	9,716
	Non-Labor Overhead	0	0
	Non-Labor Other	11,948	18,225

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Demand Response
($000)

Case No.: U-22070
Exhibit No.: A-111 (AMG-4)
Page: 2 of 2
Witness: AMGast
Date: June 2026

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Actual 12 Mos Ending 12/31/2025**	**Inflation Applied to Projected Test Year**	**Scope/ Cost Increases Net of Productivity Gains**	**Projected O&M 12 Mos Ending 4/30/2028**
			(b) * Compounded Inflation Rate		(b) + (c) + (d)
1	Demand Response (C&I)	17,511	1,094	1,675	$ 20,280
2	Demand Response (Res)	11,894	743	711	13,348
3	Total Demand Response O&M Expenses	29,406	1,837	2,386	33,628

Notes

	12-Mo Ending 2026	**12-Mo Ending 2027**	**4-Mo Ending 2028**	**Compounded Inflation Rate**
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Demand Response Program Investments and Variance

Case No.: U-22070
Exhibit No.: A-112 (AMG-5)
Page: 1 of 2
Witness: AMGast
Date: June 2026

Line No.	Description	Actual	Total Prorated Approved	Variance (Act. - App.)	Source
		(a)	(b)	(c)	
	Operating Expenses				
1	Program Delivery	$ 9,014,111	$ 13,016,347	$ (4,002,237)	A-112 (AMG-5), page 2
2	Administrative	11,859,500	13,383,186	(1,523,685)	A-112 (AMG-5), page 2
3	Customer Payments	8,569,472	9,479,192	(909,720)	A-112 (AMG-5), page 2
4	Pilots	-	-	-	A-112 (AMG-5), page 2
5	**Total Operating Expenses**	**29,443,083**	**35,878,725**	**(6,435,642)**	
6	**Customer Tariff Credits**	**8,225,218**	**9,162,338**	**(937,120)**	A-112 (AMG-5), page 2
	Capital Expenses				
7	Device Installations	(750,988)	$ 2,070,490	(2,821,478)	A-112 (AMG-5), page 2
8	IT Projects	268,120	93,333	174,787	A-112 (AMG-5), page 2
9	**Total Capital Expenses**	**(482,868)**	**2,163,823**	**(2,646,691)**	
10	**Return, Depreciation and Personal Property Tax**	**$7,886,691**	**$10,105,858**	**$ (2,219,167)**	A-114 (AMG-7), Line 5; col. g and col. d
11	Total Revenue Requirement	$ 45,554,992	$ 55,146,921	(9,591,929)	Line 5 + Line 6 + Line 10
12	**Total 2025 Under / (Over) Recovery**			**$ (9,591,929)**	
13	Interest 2023-2028			(829,614)	WP-AMG-1
14	**Total Included in Rate Design**			**$ (10,421,543)**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Demand Response Program Investments and Variance

Case No.: U-22070
Exhibit No.: A-112 (AMG-5)
Page: 2 of 2
Witness: AMGast
Date: June 2026

Line No.	Description	Actual	U-21389 Approved	U-21585 Approved	Total Prorated Approved [3]	Variance (Act. - App.)
		(a)	(b)	(c)	(d)	(e)
	Residential Demand Response					
	Operating Expenses					
1	AC Peak Cycling	$ 1,324,297	$ 2,644,592	$ 764,199	$ 1,140,277	$ 184,020
2	Dynamic Peak Pricing	52,822	211,673	206,667	207,668	(154,846)
3	Smart Thermostat Program	5,385,185	9,869,723	6,065,382	6,826,250	(1,441,065)
4	Pilots [1]	-	-	-	-	-
5	Administration	5,149,192	6,323,672	6,225,416	6,245,068	(1,095,876)
6	**Total Operating Expenses**	11,911,495	19,049,660	13,261,663	14,419,263	(2,507,768)
	Capital Expenses					
7	AC Peak Cycling	$ (864,604)	$ 6,837,959	$ 608,957	$ 1,854,757	$ (2,719,361)
8	Water Heater Cycling	1,127	-	-	-	1,127
9	Backup Generator Cycling	-	-	-	-	-
10	IT Projects	(35,288)	-	116,667	93,333	A-114 (AMG-7), Line 5; col. g and col. d
11	**Total Capital Expenses**	$ (898,765)	$ 6,837,959	$ 725,623	1,948,090	$ (2,846,855)
12	Customer Tariff Credits [2]					
13	AC Peak Cycling	$ 1,346,974	2,788,996	1,344,000	1,632,999	$ (286,025)
14	Dynamic Peak Pricing	(15)	1,268,033	1,442,000	1,407,207	(1,407,222)
15	Backup Generator Cycling	-	-	-	-	-
16	Water Heater Cycling	0	45,120	-	9,024	(9,024)
17	**Total Customer Tariff Credits**	$ 1,346,959	$ 4,102,149	$ 2,786,000	$ 3,049,230	$ (1,702,271)
	Business Demand Response					
	Operating Expenses					
18	Administrative	$ 6,710,309	$ 5,442,078	$ 7,003,631	$ 6,691,321	$ 18,988
19	Program Delivery	2,251,807	1,970,423	4,899,875	4,313,985	(2,062,178)
20	Customer Payments	8,569,472	9,912,629	9,370,833	9,479,192	(909,720)
21	**Total Operating Expenses**	$ 17,531,588	$ 17,325,130	$ 21,274,340	20,484,498	$ (2,952,910)
	Capital Expenses					
22	IT Projects	$ 303,408	-	$ -	$ -	$ 303,408
23	Portal/Switch Installations	112,489	346,663	183,000	215,733	(103,244)
24	**Total Capital Expenses**	$ 415,897	$ 346,663	$ 183,000	215,733	$ 200,164
	Customer Tariff Credits [2]					
25	Secondary Interruptible Provision (GI)	$ 96	496,000	$ 590,000	$ 571,200	$ (571,104)
26	Primary Interruptible Provision (GI)	2,966,975	1,710,000	1,927,000	1,883,600	1,083,375
27	EIP Discount (included in rate)	3,911,188	5,291,541	3,250,000	3,658,308	252,880
28	**Total Customer Tariff Credits**	$ 6,878,259	$ 7,497,541	$ 5,767,000	$ 6,113,108	$ 765,151
	Small Business Demand Response					
	Operating Expenses					
29	Administrative	$ -	$ 2,233,986	$ -	$ 446,797	$ (446,797)
30	Program Delivery	-	2,640,836	-	528,167	(528,167)
31	**Total Operating Expenses**	$ -	$ 4,874,822	$ -	$ 974,964	$ (974,964)

[1] Includes Water Heater Cycling (Multi-use Switch) and Smart Home Pilots

[2] Included in Rate Design / Approved in U-21224 EX A-16 (HWM-3) page 1 column (g); U-21389 EX S-6

[3] Days Effective:

	Begin:	End:	Number of Days:	Percentage of Days:
U-21389	1/1/2025	3/14/2025	73	20%
U-21585	3/15/2025	12/31/2025	292	80%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

2025 Annual Demand Response Program Enrollments

Case No.: U-22070
Exhibit No.: A-113 (AMG-6)
Page: 1 of 1
Witness: AMGast
Date: June 2026

Line No.	Description	Customers Enrolled				MWs Enrolled			
		Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
	Residential[(1)]								
1	AC Peak Cycling	93,872	89,990	86,020	83,882	56.2	53.8	51.6	50.4
2	Dynamic Peak Pricing	183,338	190,516	199,841	206,404	39.4	41.0	43.1	44.4
3	Smart Thermostat	60,268	63,115	62,063	64,534	55.5	58.1	57.1	59.4
4	Total	337,478	343,621	347,924	354,820	151.1	152.9	151.8	154.2
	Business Contractual Program								
5	Emergency	1,402	1,402	1,474	1,474	249.0	249.0	279.8	279.8
	Rate Programs								
6	GI & GI2 Provisions	22	22	22	22	209.5	209.5	282.4	209.5
7	Rate EIP	16	16	15	15	50.0	50.0	50.0	50.0
8	**Total DR Portfolio**	**338,918**	**345,061**	**349,435**	**356,331**	**659.6**	**661.4**	**764.0**	**693.5**

[(1)] Residential and business customer and MWs are cumulative

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response Capex Revenue Requirement Calculation
for the 2025 Reconciliation Period
($000)

Case No.: U-22070
Exhibit No.: A-114 (AMG-7)
Page: 1 of 1
Witness: AMGast
Date: June 2026

		Approved			Actual		
Line	Description	Residential Demand Response	Business Demand Response	Total Amount	Residential Demand Response	Business Demand Response	Total Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Total Rate Base	41,557	3,468	45,025	38,653	3,648	42,300
2	Pre-Tax Rate of Return	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%
3	Return On Investment	3,146	263	3,409	2,926	276	3,203
4	Depreciation & R&PP Tax	5,818	879	6,697	3,956	728	4,684
5	Total Capex Revenue Requirement	$ 8,964	$ 1,142	$ 10,106	$ 6,883	$ 1,004	$ 7,887
6			Actual less Approved:		$ (2,081)	$ (138)	$ (2,219)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Demand Response Levelized Costs

Case No.: U-22070
Exhibit No.: A-115 (AMG-8)
Page: 1 of 1
Witness: AMGast
Date: June 2026

Line No.		2015	2024	2030	2035	2040	2041	2042	2043	2044	2045
1	Enrolled Capacity (MW)	-	633.1	676.0	674.0	678.0	676.0	673.0	671.0	668.0	663.0
2	2021 IRP Target (MW)	-	630.0	698.0	698.0	698.0	698.0	698.0	699.0	700.0	701.0
3	Revenue Requirement ($000)										
4	O&M	210.2	31,263.6	36,676.8	34,594.5	32,630.5	32,251.3	31,876.5	31,506.0	31,139.9	30,778.0
5	Customer Credits	37.0	10,604.0	11,354.0	12,734.0	14,018.3	14,252.3	14,494.0	14,740.7	15,002.7	14,978.7
6	Depreciation	7.7	4,762.9	4,527.4	3,621.3	16.4	11.9	8.6	6.2	4.5	3.3
7	Return	9.0	3,209.5	1,563.4	111.0	-	-	-	-	-	-
8	R&PP Tax	1.6	698.7	645.6	656.4	658.6	658.7	658.8	658.9	659.0	659.0
9	Total	265.5	50,538.7	54,767.1	51,717.2	47,323.8	47,174.2	47,037.9	46,911.9	46,806.0	46,418.9
10	**Levelized Cost ($000/MW)**	**76.399**									
	Including Financial Incentive ($000)										
11	Levelized Cost	77.7	76.4	76.3	76.3	76.3	76.3	76.3	76.3	76.3	76.3
12	75% of CONE			-	-	-	-	-	-	-	-
13	Financial Incentive		7,703.6	7,703.6	7,703.6	7,703.6	7,703.6	7,703.6	7,703.6	7,703.6	7,703.6
14	Total with Financial Incentive	265.5	58,242.3	62,470.7	59,420.8	55,027.4	54,877.8	54,741.5	54,615.5	54,509.6	54,122.5
15	**Levelized Cost with Financial Incentive ($000/MW)**	**86.597**									

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2025 DR Financial Incentive
Shared Savings Methodology

Case No.: U-22070
Exhibit No.: A-116 (AMG-9)
Page: 1 of 1
Witness: AMGast
Date: June 2026

Line No.	Program	Levelized Cost $/MW	75% of CONE $/MW	MISO Registered MW (1)	Weighted Cost	Weighted CONE	Shared Difference
	(a)	(b)	(c)	(d)	(e) (b) x (d)	(f) (c) x (d)	(g) ((f) - (e)) x % shared
	2025 Actual						
1	Device Cycling	$ 188,504	$ 98,198	35	$ 6,597,635	$ 3,436,913	$ (1,580,361)
2	Dynamic Peak Pricing	22,003	98,198	31	683,842	3,051,978	1,184,068
3	Smart Thermostat Program	158,351	98,198	44	6,967,442	4,320,690	(1,323,376)
4	Commercial & Industrial	60,915	98,198	506	30,792,391	49,638,836	9,423,222
5	**Financial Incentive = sum of col (g), lines 1-4**						**$ 7,703,553**
6							
7							
8	130,930 CONE PY 2025/26						
9	50% Percent of savings shared						

(1) MISO registered MW for 2025/2026 planning year. Except Dynamic Peak Pricing, which is not registered with MISO so 70% of enrolled MW was used

Schedule B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
For Transportation Electrification Plan
($000)

Case No.: U-22070
Exhibit No.: A-12 (AMG-10)
Schedule: B-5.9
Page: 1 of 2
Witness: AMGast
Date: June 2026

Line No	Description	(a)	(b)	(c)	(d)	(e)	(f)
			Historical Year	Projected Bridge Year			Projected Test Year
			12 Mos Ended 12/31/2025	12 Mos Ending 12/31/2026	4 Mos Ending 4/30/2027	16 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028
1	PowerMiDrive		1,317	589	0	589	0
	Labor		345	0	0	0	0
	Capitalized E&S		196	0	0	0	0
	Materials		252	0	0	0	0
	Contractor		252	589	0	589	0
	Non-Labor Overhead		77	0	0	0	0
	Non-Labor Other		194	0	0	0	0
	Contingency		0	0	0	0	0
2	PowerMiFleet		673	4	0	4	0
	Labor		162	0	0	0	0
	Capitalized E&S		101	0	0	0	0
	Materials		135	0	0	0	0
	Contractor		148	4	0	4	0
	Non-Labor Overhead		35	0	0	0	0
	Non-Labor Other		92	0	0	0	0
	Contingency		0	0	0	0	0
3	Total Electric Transportation Capital		1,990	593	0	593	0
	Labor		507	0	0	0	0
	Capitalized E&S		297	0	0	0	0
	Materials		387	0	0	0	0
	Contractor		400	593	0	593	0
	Non-Labor Overhead		112	0	0	0	0
	Non-Labor Other		286	0	0	0	0
	Contingency		0	0	0	0	0

Schedule B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
For Transportation Electrification Plan
($000)

Case No.: U-22070
Exhibit No.: A-12 (AMG-10)
Schedule: B-5.9
Page: 2 of 2
Witness: AMGast
Date: June 2026

	(a)	(b)	(c)	(d)	(e)
		Projected			
		4 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028	28 Mos Ending 4/30/2028
4	PowerMiDrive	189	400	0	589
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	0	0
	Contractor	189	400	0	589
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
5	PowerMiFleet	4	0	0	4
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	0	0
	Contractor	4	0	0	4
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
6	Total Electric Transportation Capital	193	400	0	593
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	0	0
	Contractor	193	400	0	593
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Electric Transportation Deferred Asset Costs
($000)

Case No.: U-22070
Exhibit No.: A-117 (AMG-11)
Page: 1 of 1
Witness: AMGast
Date: June 2026

Line No.	Description	2022 Actual	2023 Actual	2024 Actual	2025 Actual	Projected 12-Mos Ending 4/30/2028
1	**Residential**					
	Education, Awareness, & Labor	2,262	2,482	2,232	2,882	3,027
	IT Development	883	838	647	602	761
	L2 Rebates	0	498	1,099	1,485	4,206
	Make Ready	0	0	0	0	0
	Residential EV Total	**3,145**	**3,817**	**3,978**	**4,969**	**7,994**
2	**Income Qualified**					
	Education, Awareness, & Labor	0	368	919	1,171	2,218
	IT Development	0	0	0	0	100
	L2 Rebates	342	160	457	635	2,967
	DCFC Rebates	390	770	2,380	2,170	0
	Make Ready	0	0	0	0	0
	Income Qualified EV Total	**732**	**1,298**	**3,756**	**3,976**	**5,284**
3	**Commercial**					
	Education, Awareness, & Labor	1,225	1,202	1,743	1,719	1,879
	IT Development	420	285	149	174	690
	L2 Rebates	140	266	434	517	690
	Income Qualified Incentives	0	612	946	2,101	0
	DC Rebates	0	165	275	75	180
	Make Ready	0	378	0	0	0
	Commercial EV Total	**1,785**	**2,906**	**3,548**	**4,585**	**3,439**
4	**Electric Transportation Total**	**$ 5,661**	**$ 8,022**	**$ 11,282**	**$ 13,531**	**$ 16,718**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
PowerMI Drive & PowerMI Fleet Cost Benefit Analysis

Case No: U-22070
Exhibit: A-118 (AMG-12)
Page: 1 of 1
Witness: AMGast
Date: June 2026

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(l)
				2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
	Revenue Requirement														
1	TEPs	Rev. Req. "Summary" Tab		$ 7,747,845	$ 10,429,381	$ 12,670,830	$ 15,030,260	$ 17,132,404	$ 18,735,446	$ 20,245,796	$ 22,243,444	$ 24,159,402	$ 26,328,186	$ 28,766,685	$ 31,388,331
	Energy Costs														
2	On Peak Avg LMP ($/kWh)	"Cost Input" Tab		$ 0.04027	$ 0.04226	$ 0.04140	$ 0.03955	$ 0.03835	$ 0.04385	$ 0.04511	$ 0.04478	$ 0.04449	$ 0.04480	$ 0.04074	$ 0.03900
3	Off Peak Avg LMP ($/kWh)	"Cost Input" Tab		$ 0.03538	$ 0.03786	$ 0.03745	$ 0.03587	$ 0.03423	$ 0.03894	$ 0.04094	$ 0.04140	$ 0.04062	$ 0.04086	$ 0.03394	$ 0.03395
			On/Off Peak												
4	On Peak Usage (kWh)	"Forecast Input" Tab	4.9%	9,884,107	13,337,330	21,158,129	33,175,644	48,127,985	64,459,173	83,586,261	107,542,719	133,187,916	157,915,397	181,950,520	205,401,578
5	Off Peak Usage (kWh)	"Forecast Input" Tab	95.1%	191,832,368	258,853,086	410,640,428	643,878,324	934,075,789	1,251,034,152	1,622,255,810	2,087,206,641	2,584,932,825	3,064,847,813	3,531,325,389	3,986,467,360
6	Total Usage			201,716,475	272,190,416	431,798,557	677,053,969	982,203,774	1,315,493,325	1,705,842,071	2,194,749,360	2,718,120,741	3,222,763,211	3,713,275,908	4,191,868,938
7	Total Energy Costs			**$ 7,185,095**	**$ 10,363,849**	**$ 16,254,526**	**$ 24,408,097**	**$ 33,819,090**	**$ 51,541,934**	**$ 70,185,528**	**$ 91,226,277**	**$ 110,925,556**	**$ 132,303,996**	**$ 127,266,576**	**$ 143,350,616**
	Production Capacity Costs														
8	75% of CONE	"Cost Input" Tab		$ 103.13	$ 105.18	$ 107.27	$ 109.40	$ 111.58	$ 113.80	$ 116.06	$ 118.36	$ 120.72	$ 123.11	$ 125.56	$ 128.06
9	Demand during 1CP (KW)	"Load Input" Tab		27,205	27,780	44,768	71,532	105,109	141,945	185,544	239,785	300,228	361,619	415,752	465,730
10	Total Production Capacity Costs			**$ 2,805,727**	**$ 2,921,991**	**$ 4,802,367**	**$ 7,825,903**	**$ 11,727,887**	**$ 16,152,730**	**$ 21,533,637**	**$ 28,381,652**	**$ 36,242,044**	**$ 44,520,451**	**$ 52,202,136**	**$ 59,639,509**
	Transmission Costs		Growth Rate												
11	Embedded Cost	"Cost Input" Tab	7.9%	$ 8.35	$ 9.00	$ 9.71	$ 10.48	$ 11.30	$ 12.19	$ 13.15	$ 14.18	$ 15.29	$ 16.49	$ 17.79	$ 19.19
12	Demand during 12CP (KW)	"Load Input" Tab		318,018	328,386	526,980	834,524	1,228,031	1,654,852	2,158,621	2,777,923	3,469,908	4,178,509	4,795,945	5,360,866
13	Total Transmission Costs			**$ 2,654,956**	**$ 2,957,001**	**$ 5,118,244**	**$ 8,742,327**	**$ 13,875,803**	**$ 20,168,258**	**$ 28,375,691**	**$ 39,386,827**	**$ 53,065,147**	**$ 68,924,469**	**$ 85,327,101**	**$ 102,874,674**
	Distribution Costs		Growth Rate												
14	Embedded Cost	"Cost Input" Tab	9.4%	$ 241.62	$ 264.39	$ 289.30	$ 316.56	$ 346.39	$ 379.03	$ 414.74	$ 453.82	$ 496.59	$ 543.38	$ 594.58	$ 650.61
15	Demand during 1CP (KW)	"Load Input" Tab		27,205	27,780	44,768	71,532	105,109	141,945	185,544	239,785	300,228	361,619	415,752	465,730
16	Total Distribution Costs			**$ 6,573,269**	**$ 7,344,750**	**$ 12,951,371**	**$ 22,644,207**	**$ 36,408,656**	**$ 53,801,336**	**$ 76,953,209**	**$ 108,820,137**	**$ 149,089,309**	**$ 196,496,858**	**$ 247,198,914**	**$ 303,008,339**
	Total TEP Costs														
17	Costs (RR and Energy Only)			$ 14,932,940	$ 20,793,230	$ 28,925,356	$ 39,438,358	$ 50,951,494	$ 70,277,380	$ 90,431,324	$ 113,469,721	$ 135,084,959	$ 158,632,182	$ 156,033,260	$ 174,738,947
18	Total Costs			$ 26,966,893	$ 34,016,972	$ 51,797,339	$ 78,650,795	$ 112,963,840	$ 160,399,703	$ 217,293,860	$ 290,058,337	$ 373,481,459	$ 468,573,959	$ 540,761,411	$ 640,261,468
19	**Total Related Revenue**	"Revenue Input" Tab		$ 32,511,512	$ 49,509,430	$ 85,574,512	$ 139,203,450	$ 209,369,938	$ 290,301,429	$ 389,840,756	$ 519,554,950	$ 666,501,146	$ 835,137,072	$ 977,720,255	$ 1,146,515,565
			WACC												
20	**Net Costs/Revenues**	NPV	6.1%												
21	Rev/RR Energy Only Costs	$2,002,309,723		$ 17,578,572	$ 28,716,200	$ 56,649,156	$ 99,765,092	$ 158,418,444	$ 220,024,049	$ 299,409,432	$ 406,085,229	$ 531,416,187	$ 676,504,890	$ 821,686,995	$ 971,776,618
22	Rev/Total Costs	$1,115,524,558		$ 5,544,620	$ 15,492,458	$ 33,777,174	$ 60,552,655	$ 96,406,098	$ 129,901,726	$ 172,546,896	$ 229,496,613	$ 293,019,687	$ 366,563,112	$ 436,958,845	$ 506,254,096

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

BRITTANI A. GRAY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

1. Tariff Sheet Nos. A-5.00, C-12.00, C-26.00, C-64.30, D-9.00, D-10.00, and D-19.00 through D-24.00 – **Residential Electric Heating Rate REH** – Added a new electric heating rate for residential customers and reformatted tariff sheets.

2. Tariff Sheet No. C-4.00 – Rule C1 – **Characteristics of Service** – Updated Contribution in Aid of Construction Allowance.

3. Tariff Sheet No. C-15.00 – Rule C4.4 – **Resale** – Revised all inclusive resale rate per kWh.

4. Tariff Sheet No. C-18.00 – Rule C4.5 – **Mobile Home Park** – Updated New Service Connection fee for underground service (Mobile Home Park).

5. Tariff Sheet No. C-26.20 and C-27.00 – Rule C6.1 – **Overhead Extension Policy** – Updated Overhead New Service Connection fees, Line Extension charges over 600 feet and Residential direct connect refund.

6. Tariff Sheet Nos. C-31.00 and C-32.00 – Rule C6.2 – **Underground Policy** – Updated New Service Connection fee for underground service.

7. Tariff Sheet No. C-36.00 – Rule C8 – **Power Supply Cost Recovery** – Updated the Power Supply Cost Recovery (PSCR) adjustment factor.

8. Tariff Sheet No. C-49.00 – Rule C10.3 – **Experimental Advanced Renewable Program (AR Program)** – Revised AR Program tariffs to define process upon contract expiration.

9. Tariff Sheet Nos. C-64.30 through C-64.50 – Rule C11.3 – **Distributed Generation Program** – Updated Distributed Generation Program tariffs to reflect revised outflow credits and reformatted tariff sheets.

10. Tariff Sheet Nos. C-77.00, D-66.00, D-78.20, D-82.00, E-22.00, E-24.00 and E-26.00 – **Line Loss Factors** – Updated line loss factors.

11. Tariff Sheet Nos. C-79.00 through C-82.00 – Rule C19 – **Transportation Electrification Programs (TEPs)** – Updated tariffs to remove On-Bill Installment Payment Plan, pre-approved EV installer requirement, modified AMI Monitoring credit, broadened eligibility, and revised separate metering requirements.

12. Tariff Sheet Nos. D-2.20, D-2.40, and D-5.00 – **Surcharges** – Updated Investment Recovery Mechanism Surcharge, Electric Rate Case Deferral Surcharge, and Electric Rate Case Demand Response Surcharge.

13. Tariff Sheet Nos. D-14.00, D-15.00, D-17.00, D-36.00, D-36.10, D-38.00, D-40.00, D-40.50, D-42.00, D-43.00, D-44.10, D-44.20, D-45.00, D-46.00, D-48.00 through D-50.00, D-51.00, D-53.00, D-55.00 through D-57.00, D-59.00 through D-63.00, D-66.00, D-67.10 through D-67.30, D-71.00, D-72.00, D-75.00 through D-77.00, D-78.20, D-78.30, D-82.00 through D-83.10, D-85.00, D-86.00, D-90.10, D-90.20, D-94.00, D-94.20, D-94.30 and D-96.00 – **Rate Schedules** – Revised prices for electric rate schedules.

14. Tariff Sheet Nos. D-17.00, D-38.00, and D-42.00 – **Residential Peak Reward Program** – Removed the control group participation credit.

15. Tariff Sheet No. D-36.00 – **Residential Smart Hours Rate RSH** – Clarified eligibility of Rate RSH.

16. Tariff Sheet Nos. D-78.30 through D-78.50 – **Large Economic Development Rate LED** – Added Adjustment for Power Factor and reformatted tariff sheets.

17. Tariff Sheet Nos. D-88.00 and D-89.00 – **General Unmetered Lighting Rate GUL** – Revised eligibility and clarified rate transition following LED Conversion.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Proposed Electric Tariff Sheets (MPSC No. 14 - Redlined Version)

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Proposed Electric Tariff Sheets (MPSC No. 14 - Redlined Version)

For all pricing changes on the following tariff sheets, refer to Exhibit A-16 (MCG-3) Schedule F-3.0, Pages 1-24

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. A-5.00**

INDEX

(Continued From Sheet No. A-4.00)

SECTION D
RATE SCHEDULES (Contd)

	Sheet No.
RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP	D-14.00
RESIDENTIAL ELECTRIC HEATING RATE REH	*D-19.00*
RESIDENTIAL SMART HOURS RATE RSH	D-36.00
RESIDENTIAL NIGHTTIME SAVERS RATE RPM	D-40.00
RESIDENTIAL SERVICE SECONARY NON-TRANSMITTING METER RATE RSM	D-44.10
GENERAL SERVICE SECONDARY RATE GS	D-45.00
GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU	D-48.00
GENERAL SERVICE SECONDARY DEMAND RATE GSD	D-51.00
GENERAL SERVICE PRIMARY RATE GP	D-55.00
LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD	D-59.00
GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU	D-70.00
ENERGY INTENSIVE PRIMARY RATE EIP	D-74.00
LARGE ECONOMIC DEVELOPMENT RATE LED	D-78.10
EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR	D-79.00
GENERAL SERVICE SELF GENERATION RATE GSG-2	D-81.00
LONG TERM INDUSTRIAL LOAD RETENTION RATE - LTILRR	D-84.10
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GENERAL SERVICE UNMETERED LIGHTING RATE GUL	D-88.00
GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED	D-93.00
GENERAL SERVICE UNMETERED RATE GU	D-96.00
POLE ATTACHMENT AND CONDUIT USE RATE PA	D-99.00

(Continued on Sheet No. A-6.00)

See Gray Testimony, Page 11, Lines 1-4; Exhibit A-120 (BAG-1), Item No. 1

(Continued From Sheet No. C-3.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.4 Extraordinary Facility Requirements and Charges (Contd)

Contribution In Aid of Construction Allowance Schedule							
Schedule	Customer Voltage Level (CVL)	With a Full Service Contract, by Contract Duration					Without Full Service Contract
		1 Year	2 Year	3 Year	4 Year	5 Year	
General Service Primary Rate GP	1	*$0.012/kWh* ~~$0.010/kWh~~	*$0.023/kWh* ~~$0.020/kWh~~	*$0.034/kWh* ~~$0.029/kWh~~	*$0.043/kWh* ~~$0.037/kWh~~	*$0.052/kWh* ~~$0.045/kWh~~	*$0.012/kWh* ~~$0.010/kWh~~
	2	*$0.016/kWh* ~~$0.013/kWh~~	*$0.032/kWh* ~~$0.026/kWh~~	*$0.046/kWh* ~~$0.037/kWh~~	*$0.059/kWh* ~~$0.048/kWh~~	*$0.071/kWh* ~~$0.058/kWh~~	*$0.016/kWh* ~~$0.013/kWh~~
	3	*$0.028/kWh* ~~$0.023/kWh~~	*$0.053/kWh* ~~$0.044/kWh~~	*$0.077/kWh* ~~$0.064/kWh~~	*$0.099/kWh* ~~$0.082/kWh~~	*$0.119/kWh* ~~$0.099/kWh~~	*$0.028/kWh* ~~$0.023/kWh~~
Large General Service Primary Demand Rate GPD	1	*$55/kW* ~~$30/kW~~	*$100/kW* ~~$55/kW~~	*$150/kW* ~~$80/kW~~	*$190/kW* ~~$105/kW~~	*$230/kW* ~~$125/kW~~	*$55/kW* ~~$30/kW~~
	2	*$65/kW* ~~$45/kW~~	*$125/kW* ~~$85/kW~~	*$180/kW* ~~$125/kW~~	*$230/kW* ~~$160/kW~~	*$275/kW* ~~$195/kW~~	*$65/kW* ~~$45/kW~~
	3	*$100/kW* ~~$70/kW~~	*$195/kW* ~~$135/kW~~	*$280/kW* ~~$195/kW~~	*$360/kW* ~~$250/kW~~	*$435/kW* ~~$305/kW~~	*$100/kW* ~~$70/kW~~
General Service Primary Time-of-Use Rate GPTU	1	*$0.014/kWh* ~~$0.009/kWh~~	*$0.026/kWh* ~~$0.018/kWh~~	*$0.038/kWh* ~~$0.026/kWh~~	*$0.049/kWh* ~~$0.034/kWh~~	*$0.059/kWh* ~~$0.041/kWh~~	NA
	2	*$0.015/kWh* ~~$0.011/kWh~~	*$0.029/kWh* ~~$0.021/kWh~~	*$0.041/kWh* ~~$0.030/kWh~~	*$0.053/kWh* ~~$0.039/kWh~~	*$0.064/kWh* ~~$0.047/kWh~~	NA
	3	*$0.018/kWh* ~~$0.014/kWh~~	*$0.036/kWh* ~~$0.027/kWh~~	*$0.051/kWh* ~~$0.039/kWh~~	*$0.066/kWh* ~~$0.050/kWh~~	*$0.080/kWh* ~~$0.061/kWh~~	NA
Energy Intensive Primary Rate EIP	1	*$0.005/kWh* ~~$0.0003/kWh~~	*$0.009/kWh* ~~$0.0005/kWh~~	*$0.013/kWh* ~~$0.0008/kWh~~	*$0.017/kWh* ~~$0.0010/kWh~~	*$0.021/kWh* ~~$0.0012/kWh~~	NA
	2	*$0.007/kWh* ~~$0.0021/kWh~~	*$0.013/kWh* ~~$0.0041/kWh~~	*$0.018/kWh* ~~$0.0060/kWh~~	*$0.023/kWh* ~~$0.0077/kWh~~	*$0.028/kWh* ~~$0.0093/kWh~~	NA
	3	*$0.009/kWh* ~~$0.0037/kWh~~	*$0.018/kWh* ~~$0.0072/kWh~~	*$0.026/kWh* ~~$0.0105/kWh~~	*$0.033/kWh* ~~$0.0135/kWh~~	*$0.040/kWh* ~~$0.0162/kWh~~	NA

The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, minimum bills, require upfront deposit and other service conditions, including, but not limited to, when the customer's load requirements are of a short-term duration, temporary or a transient nature, or if in the opinion of the Company, the customer does not have acceptable credit history or represents an unacceptable credit risk or other reasons within the sound discretion of the Company.

Contributions in Aid of Construction otherwise required by the Company may be suspended for charging sites participating in the PowerMIDrive Public or PowerMIFleet programs.

C1.5 Invalidity of Oral Agreements or Representations

When a written contract is required, no employee or agent of the Company is authorized to modify or supplement the Rules and Regulations and Rate Schedules of the Electric Rate Book by oral agreement or representation, and no such oral agreement or representation shall be binding upon the Company.

(Continued on Sheet No. C-5.00)

(Continued From Sheet No. C-11.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

A. Residential Usage and Rate Application (Contd)

(3) Homes or Dormitories for Groups Other Than Private Family Dwellings
Tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons where residential usage is metered and consumed shall be classified as residential and billed on a Residential Service Rate. The landlord and his/her immediate family are not included in the six-person limitation.

(4) Multifamily Dwellings

(a) General

A "multifamily dwelling" shall be considered any duplex, apartment building, mobile home park, condominium, cooperative or other grouping of households. All newly constructed multifamily dwellings shall have separately metered households. The requirement for separately metered households may be waived at the request of the developer in cases where newly constructed or rehabilitated duplexes, apartment buildings and other multifamily dwellings are owned by a nonprofit corporation or "flow-through entity," which have a long-term regulatory agreement with the Michigan State Housing Development Authority, the United States Department of Housing and Urban Development or the United States Department of Agriculture to provide affordable housing for qualifying low-income residents. Separately metered households shall be required in the event the property is no longer subject to such regulatory agreement; the owner must notify Consumers Energy and all costs associated with conversion from a single metered facility to separately metered multifamily dwellings shall be the responsibility of the property owner. Any spaces within the development used for commercial purposes shall be separately metered by Consumers Energy.

(b) Common Area Usage in Multifamily Dwellings Containing Separately Metered Households

Common area usage, excluding mobile home parks, shall be metered and billed as follows:

(i) Dwellings containing less than five households shall be separately metered and billed on a Residential Service Rate. When the landlord lives in one of the units, the common area usage may be metered and billed through the landlord's meter.rent
(ii) Dwellings containing five or more households shall be separately metered and billed on the appropriate General Service Rate.

Common area usage in mobile home parks shall be separately metered and billed on the appropriate General Service Rate.

(c) Multifamily Dwellings Served Through a Single Meter

A multifamily dwelling served through a single meter shall be billed as follows:

(i) Dwellings containing two households, including common area, shall be billed on Residential On-Peak Summer Basic Rate RSP. Residential Electric Vehicle Program participants may take service on *Residential Electric Heating Rate REH,* Residential Smart Hours Rate RSH or Residential Nighttime Savers Rate RPM.
(ii) Dwellings containing three or four households, including common area, shall be billed on Residential On-Peak Summer Basic Rate RSP or the appropriate General Service Rate. Residential Electric Vehicle Program participants may take service on *Residential Electric Heating Rate REH,* Residential Smart Hours Rate RSH or Residential Nighttime Savers Rate RPM.
(iii) Dwellings containing five or more households, including common area, shall be billed on the appropriate General Service Rate.

(Continued on Sheet No. C-13.00)

(Continued From Sheet No. C-14.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

D. Rate Application for Seasonal Condominium Campgrounds (Contd)

(6) The customer must notify individuals and co-owners utilizing the customer's property that requests and concerns regarding electric service will be addressed between the single legal entity and ownership and primary operating authority, not with individuals.

(7) The customer shall be responsible for ensuring that the electrical facilities are adequate to meet the needs of the units placed within the Seasonal Condominium Campground in their entirety and shall pay the Company for any charges incurred for modifications necessary to accommodate load according to other portions of this Electric Rate Book.

C4.4 Resale

This provision is closed to resale for general unmetered service, unmetered or metered lighting service and new or expanded service for resale for residential use.

No customer shall resell electric service to others except when the customer is served under a Company rate expressly made available for resale purposes, and then only as permitted under such rate and under this rule.

Where, in the Company's opinion, the temporary or transient nature of the proposed ultimate use, physical limitation upon extensions, or other circumstances, make it impractical for the Company to extend or render service directly to the ultimate user, the Company may allow a customer to resell electric service to others.

For the purposes of this tariff, the provision of electric vehicle charging service for which there is no direct per kWh charge shall not be considered resale of service.

A resale customer is required to take service under the resale provision of one of the following rates for which they qualify: General Service Secondary Rate GS, General Service Secondary Time-of-Use Rate GSTU, General Service Secondary Demand Rate GSD, General Service Primary Rate GP, Large General Service Primary Demand Rate GPD, or General Service Primary Time-of-Use Rate GPTU. Resale Service is provided pursuant to a service contract providing for such resale privilege. Service to each ultimate user shall be separately metered.

A. If the resale customer elects to take service under a Company Full Service resale rate, the ultimate user shall be served and charged for such service under standard Rate RSM for residential use or under the appropriate standard General Service Rate applicable in the Company's Electric Rate Book available for similar service under like conditions. Reselling customers are not required to offer or administer any additional service provisions or nonstandard rates contained in the Electric Rate Book, such as the Income Assistance Service Provision or the Educational Institution Service Provision.

B. If the resale customer elects to take service under a Company Retail Open Access Service rate, the ultimate user shall be served and charged for such service under Rate ROA-R for residential use or under Rate ROA-S or ROA-P applicable in the Company's Electric Rate Book available for similar service under like conditions.

C. If the ultimate user is a campground lot or boat harbor slip, the resale customer has the option to charge a maximum of the following all inclusive rate per kWh in place of billing the ultimate customer on the appropriate standard Company tariff rate:

$~~0.207286~~ *0.228707* per kWh for all kWh during the months of June - September

$~~0.178963~~ *0.199454* per kWh for all kWh during the months of October - May

The Company shall be under no obligation to furnish or maintain meters or other facilities for the resale of service by the reselling customer to the ultimate user.

The service contract shall provide that the reselling customer's billings to the ultimate user shall be audited each year by February's month end, for the previous calendar year. The audit shall be conducted either by the Company, if the Company elects to conduct such audit, or by an independent auditing firm approved by the Company. The reselling customer shall be assessed a reasonable fee for an audit conducted by the Company. If the audit is conducted by an independent auditing firm, the customer shall submit a copy of the results of such audit to the Company in a form approved by the Company.

(Continued on Sheet No. C-16.00)

(Continued From Sheet No. C-17.00)

C4. APPLICATION OF RATES (Contd)

C4.5 Mobile Home Park - Individually Served (Contd)

B. Original Installations of Underground Service Connections From Underground Distribution Systems

The mobile home park owner or an authorized representative shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the cost resulting from the installation of the underground service connections. For the route specified by the Company, the contribution shall be ~~a flat fee of $1,300~~ *$10.20 per lineal foot, measured from the termination point of the Company's facilities to the customer's service termination point*. For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be ~~a flat fee of $1,300 plus~~ *increased by* any additional costs in excess of those associated with the route specified by the Company.

The Company shall furnish, install, own and maintain the entire underground electric distribution system including the pre-meter portion of the service lateral cables for new mobile home parks. The trenches for Primary or Secondary main cables will be occupied jointly by facilities of the Company and other utilities where satisfactory agreement for reimbursement of applicable joint facility costs exist between the Company and the other utilities.

Certain related equipment, such as pad-mounted transformers, switching equipment, and service pedestals may be above grade. The area must be suitable for the direct burial installation of cable.

The mobile home park owner or an authorized representative shall provide, own, install and maintain suitable meter supports of a design satisfactory to the Company.

C. If temporary overhead service is installed for the convenience of the mobile home park owner or an authorized representative for construction purposes, such owner or representative shall be required to pay the in-and-out costs of such overhead facilities in the underground area.

D. Where, in the Company's judgment, practical difficulties exist, such as frost or water conditions, rock near the surface, or where there are requirements for deviation from the Company's filed construction standards, the per foot charges included in this rule shall not apply and the contribution in aid of construction shall be equal to the estimated difference in cost between overhead and underground facilities but not less than the contribution calculated under the appropriate per foot charge.

E. The Company may, upon request of the owner and subject to the provisions of this rule, assume ownership of, and incorporate into its electric distribution system, all of an owner's existing electric distribution system and service connection, including distribution lines, transformers, services, meter set assemblies, meters and associated equipment. The Company, on assuming ownership, shall provide individual service and meters for each ultimate consumer. The purchase price to be paid by the Company for such distribution system shall be computed at a rate of $200 per lot for each lot with an installed service connection to the distribution system where the average age of the mobile home park is five years or less. Such rate shall be reduced by $40 per lot for each additional five-year increment in average age.

In cases where the assumption of ownership would require the Company to install new distribution facilities and service connections or modify the existing distribution system, the mobile home park owner or authorized representative may be required to make a deposit or nonrefundable contribution in aid of construction to the Company to cover the cost of such facilities.

(Continued on Sheet No. C-19.00)

See Partlan Testimony, Page 15, Line 13-15 through Page 16, Lines 1-13; Exhibit A-120 (BAG-1), Item Nos. 5-6

(Continued From Sheet No. C-25.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.6 Customer-Selected Due Date Program

Notwithstanding other provisions in this tariff book, the Company, at its discretion, may provide its electric service customers and combination electric and gas service customers the option to select the day of the month on which their bill is due, regardless of the meter read date. Participating customers must have an electric AMI transmitting technology meter.

Participation in the Customer-Selected Due Date Program is available to customers, as determined by the Company, when technically feasible based on the customer's selected rate and billing options. Customers not eligible to participate include, but not limited to, customers billed on a calendar-month basis, customers participating in Retail Open Access and customers participating in the Net Metering Program.

The Customer-Selected Due Date Program is only available for the following rate categories: Residential Summer On-Peak Basic (RSP), *Residential Electric Heating Rate (REH),* Residential Smart Hours (RSH), Residential Nighttime Savers (RPM), General Service Secondary (GS), General Service Secondary Demand (GSD), General Service Primary (GP) and General Service Metered Lighting (GML).

(Continued on Sheet No. C-26.10)

(Continued From Sheet No. C-26.10)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS

C6.1 Overhead Extension Policy

Applications for electric service which require the construction of an overhead distribution system shall be granted under the following conditions:

A. Residential Customers

The Company shall construct single-phase distribution line extensions at its own cost a distance of 600 feet, for each residential dwelling.

The length of the distribution line extension shall be measured from the nearest point of connection to the Company's facilities from which the extension can be made to the point from which the service line to the customer shall be run.

Distribution line extensions in excess of the above 600 feet shall require a deposit for the estimated cost of such excess footage. The required deposit for such excess footage shall be $~~3.50~~ *9.15* per lineal foot less 25%.

The Company shall make a one-time refund, five years from the completion date of the extension or upon completion of the customer's construction, whichever the customer chooses, of $~~1,~~000 *1,500* for each additional residential customer and/or three times the estimated annual revenue for each additional General Service customer who connects directly to the line for which a deposit was required. Refund allowances shall first be credited against the 25% reduction before a refund is made to the customer based on the customer's cash deposit. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy. Total refund shall not exceed the amount of the original deposit.

B. Installations of Overhead Service Connection - Residential

The developer or customer shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the cost resulting from the installation of an overhead service connection. For the route specified by the Company, the contribution shall be ~~a flat fee of $1,300~~ *$10.20 per lineal foot, measured from the termination point of the Company's facilities to the customer's service termination point*. For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be ~~a flat fee of $1,300 plus~~ *increased by* any additional costs in excess of those associated with the route specified by the Company.

(Continued on Sheet No. C-27.00)

(Continued From Sheet No. C-26.20)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.1 Overhead Extension Policy (Contd)

C. General Service Customers

The Company shall construct single-phase and three-phase distribution line extensions, at its own cost when the cost of such extension does not exceed three times the estimated annual revenue from the customer(s) to be immediately served.

Extensions with costs in excess of three times the estimated annual revenue shall require a deposit from the customer.

(1) Original Customers

At the end of the first complete 12-month period beginning three months following the date the line extension is completed, the Company shall refund to the depositor three times the amount that actual revenue exceeds the original revenue estimate. If the actual revenue exceeds the estimated revenue, the actual revenue then becomes the base upon which future refund calculations are to be made during the remainder of the five year refund period.

(2) Additional Connected Customers

The Company shall refund $~~1,000~~ *1,500* for each residential customer and/or three times the estimated annual revenue for each General Service customer who connects directly to the line for which a deposit was required. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not be made until the original customer(s) or equivalent is actually connected to the extension. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy.

D. Installations of Overhead Service Connection - General Service

The developer or customer shall be required to make a refundable contribution in aid of construction to the Company, to cover the cost resulting from the installation of an overhead service connection. For the route specified by the Company, the contribution shall be ~~a flat fee of $2,200~~ *$17.20 per lineal foot, measured from the termination point of the Company's facilities to the customer's service termination point*. For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be ~~a flat fee of $2,200 plus~~ *increased by* any additional costs in excess of those associated with the route specified by the Company.

E. General

(1) Refundable deposits made with the Company under this rule shall be subject to refund without interest, for a five-year period which begins three months after the line extension is completed. The Company shall have no further obligation to refund any remaining portion of line extension deposits.

(2) Each extension shall be a separate, distinct unit and any further extension therefrom shall have no effect upon the agreements under which existing extensions were constructed.

(3) Refunds cannot exceed the refundable portion of the deposit.

(4) Estimated construction costs shall exclude services and meters.

(5) The applicant shall furnish, without cost to the Company, all necessary rights-of-way and tree trimming permits, in a form satisfactory to the Company. If the applicant is unable to secure rights-of-way and permits, in a form satisfactory to the Company, the Company may extend its distribution system along an alternate route selected by the Company, and may require the applicant to pay all additional costs incurred.

(Continued on Sheet No. C-28.00)

See Partlan Testimony, Page 15, Line 13-15 through Page 16, Lines 1-13; Exhibit A-120 (BAG-1), Item Nos. 5-6

(Continued From Sheet No. C-30.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.2 Underground Policy (Contd)

B. Installations of Underground Distribution Facilities - Residential (Contd)

(2) Original Installations of Underground Distribution Systems (Contd)

(a) In subdivisions (Contd)

Where a residential underground distribution system serves lots on one side of a street, the later connection of lots on the other side of the street to that existing system shall be considered as an original installation of a residential underground distribution system for such later-connected lots.

Streetlighting, if any, shall be served underground in areas served directly by residential underground distribution systems. The character and location of the streetlighting cables, if any, and all equipment constituting the residential underground distribution system, shall conform to specifications prepared by the Company.

Where the underground cable for a residential underground distribution system extends through areas within the subdivision which are undeveloped or consist of lots platted for future use and which are not to be served initially by the system, the front-foot measurement of both sides of the street or easement along which the cable extends through such areas shall be included in determining the contribution of the owner(s) or developer(s) for the residential underground distribution system.

Where the Company and the owner(s) or developer(s) agree that it is desirable to extend the underground cable to the boundary of a subdivision property from a point outside the subdivision a contribution of $7.00 per trench foot shall be required.

(b) Outside of subdivisions

The Company shall extend its Primary or Secondary distribution system from existing overhead or underground facilities. When any such extension is made from an existing overhead system the property owner may be required to provide an easement(s) for extension of the overhead system to a pole on his/her property where transition from overhead to underground can be made.

The customer shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the estimated total difference in cost between overhead and direct burial underground facilities for all underground facilities required to serve the customer.

(3) Installation of Underground Service Connections

The developer or customer shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the cost resulting from the installation of an underground service connection. For the route specified by the Company, the contribution shall be ~~a flat fee of $1,300~~ *$10.20 per lineal foot, measured from the termination point of the Company's facilities to the customer's service termination point*. For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be ~~a flat fee of $1,300 plus~~ *increased by* any additional costs in excess of those associated with the route specified by the Company.

Where the electric service connection is installed jointly with the gas service line, the per foot charge for all footage, as measured, shall be reduced by 25 cents per foot.

(Continued on Sheet No. C-32.00)

See Partlan Testimony, Page 15, Line 13-15 through Page 16, Lines 1-13; Exhibit A-120 (BAG-1), Item Nos. 5-6

(Continued From Sheet No. C-31.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.2 Underground Policy (Contd)

C. Installations of Underground Distribution Facilities - General Service

(1) Installation of Underground Distribution Systems

The Company shall construct single-phase and three-phase distribution line extensions at its own cost, when the cost of such extension, less contributions made under other sections of this rule, does not exceed three times the estimated annual revenue from the customer(s) to be immediately served. Extensions with costs in excess of three times the estimated annual revenue shall require a deposit from the customer.

(2) Installation of Underground Service Connections

The developer or customer shall be required to make a refundable contribution in aid of construction, to cover the cost resulting from the installation of an underground service connection. For the route specified by the Company, the contribution shall be ~~a flat fee of $2,200~~ *$17.20 per lineal foot, measured from the termination point of the Company's facilities to the customer's service termination point.* For an alternate route requested by the customer and is mutually agreed upon by the Company and the customer, the contribution shall be ~~a flat fee of $2,200 plus~~ *increased by* any additional costs in excess of those associated with the route specified by the Company.

(Continued on Sheet No. C-33.00)

(Continued From Sheet No. C-35.00)

C8. POWER SUPPLY COST RECOVERY (PSCR) CLAUSE (Contd)

A. Applicability of Clause (Contd)

"Power Supply Costs" means those elements of the costs of fuel and purchased and net interchanged power as determined by the Commission to be included in the calculation of the Power Supply Cost Recovery Factor. The Commission determined in its Order in Case No. U-10335 dated May 10, 1994 that the fossil plant emissions permit fees over or under the amount included in base rates charged the Company are an element of fuel costs for the purpose of the clause.

B. Billing

(1) The Power Supply Cost Recovery Factor shall consist of an adjustment factor of ~~1.07273~~ *1.08378* applied to projected average booked cost of fuel burned for electric generation and purchased and net interchange power incurred above or below a cost base of $0.05570 per kWh (excluding line losses). Average booked costs of fuel burned and purchased and net interchange power shall be equal to the booked costs in that period divided by that period's net system kWh requirements. The average booked costs so determined shall be truncated to the full $0.00001 cost per Kilowatt-hour. Net system kWh requirements shall be the sum of the net kWh generation and net kWh purchased and interchange power.

(2) Each month the Company shall include in its rates a Power Supply Cost Recovery Factor up to the maximum authorized by the Commission as shown on Sheet No. D-6.00.

Should the Company apply lesser factors than those shown on Sheet No. D-6.00, or if the factors are later revised pursuant to Commission Orders or Michigan Compiled Laws, Annotated, 460.6 et seq., the Company shall notify the Commission if necessary and file a revised Sheet No. D-6.00.

C. General Conditions

(1) The power supply and cost review shall be conducted not less than once a year for the purpose of evaluating the Power Supply Cost Recovery Plan filed by the Company and to authorize appropriate Power Supply Cost Recovery Factors. Contemporaneously with its Power Supply Cost Recovery Plan, the Company shall file a 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply and projections of Power Supply Costs.

(2) Not more than 45 days following the last day of each billing month in which a Power Supply Cost Recovery Factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the Power Supply Cost Recovery Factor and the allowance for cost of power included in the base rates established in the latest Commission order for the Company, and the cost of power supply.

(3) All revenues collected pursuant to the Power Supply Cost Recovery Factors and the allowance for power included in the base rates are subject to annual reconciliation proceedings.

(Continued on Sheet No. C-37.00)

(Continued from Sheet No. C-48.00)

C10. RENEWABLE ENERGY PLAN (REP) (Contd)

C10.3 Experimental Advanced Renewable Program (AR Program) (Contd)

D. Contractual Price (Contd)

In subsequent allocation cycles, the price may be adjusted by the Company at its sole discretion based on the amount of capacity included in valid applications for the prior allocation cycle. For each five percent increment that the amount of capacity exceeded the amount of capacity solicited in the prior allocation cycle and the current allocation cycle, the price shall be reduced by $0.001 per kWh except that the price reduction shall be no more than $0.010 per kWh from one allocation cycle to the next allocation cycle. For each ten percent increment that the amount of capacity was less than the amount of capacity offered in that allocation, the price shall be increased by $0.001 per kWh. The price shall not be less than $0.20 per kWh or exceed $0.26 per kWh. For contracts awarded after June 30, 2013, the minimum price of $0.20 per kWh shall not apply.

For participants in the AR Program with contracts awarded after January 1, 2015, the price shall be $0.199 per kWh for Non-Residential applications and $0.24 per kWh for Residential applications. Participants providing service with a generating system constructed after October 1, 2011 that qualify for both the Michigan Labor and Michigan Material requirements shall be awarded an incentive price of $0.001 per kWh for all energy delivered.

E. Termination of Agreements

In the event that the customer ceases to operate the equipment or ownership of the equipment changes, then the customer should notify the Company of the circumstances and provide notice of the need to terminate the agreement. The premises and/or the customer referenced within a contractual agreement for service under this program may be restricted from participating in the program until after the original date set for expiration of the agreement.

Upon expiration of a customer's contractual participation in the AR Program, the customer will be enrolled in the Simple Renewable Program (SRP), unless the Company determines that enrollment is not appropriate based on the customer's generation and applicable charges. The Company shall provide notice of enrollment or alternative options to the customer. A customer may elect to discontinue participation or participate in another Company-offered program for which the customer is eligible.

(Continued on Sheet No. C-50.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-64.30**

(Continued From Sheet No. C-64.20)

C11. SELF-GENERATION, NET METERING, DISTRIBUTED GENERATION AND SIMPLE RENEWABLE PROGRAM (Contd)

C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)

E. Customer Billing

a. Full Service Customers Outflow Credit

Customers will be credited per kWh or per kW of Outflow based on the power supply rates (which include transmission costs) of their Full Service Rate Schedule as shown below, plus the PSCR factor as shown on Tariff Sheet No. D-6.00.

Residential Rates

Summer On-Peak Basic Rate RSP		
On-Peak	~~$(0.151904)~~ *(0.160854)*	per Outflow kWh between June 1 and September 30
Off-Peak	~~$(0.103970)~~ *(0.108959)*	per Outflow kWh between June 1 and September 30
All Hours	~~$(0.082996)~~ *(0.087178)*	per Outflow kWh between October 1 and May 31
Electric Heating Rate REH		
On-Peak	*$(0.160854)*	*per Outflow kWh between June 1 and September 30*
Off-Peak	*$(0.108959)*	*per Outflow kWh between June 1 and September 30*
First 750 kWh	*$(0.088035)*	*per Outflow kWh between October 1 and May 31*
Excess 750 kWh	*$(0.061252)*	*per Outflow kWh between October 1 and May 31*
Smart Hours Rate RSH		
On-Peak	~~$(0.151904)~~ *(0.160854)*	per Outflow kWh between June 1 and September 30
Off-Peak	~~$(0.103970)~~ *(0.108959)*	per Outflow kWh between June 1 and September 30
On-Peak	~~$(0.096396)~~ *(0.103352)*	per Outflow kWh between October 1 and May 31
Off-Peak	~~$(0.080437)~~ *(0.084097)*	per Outflow kWh between October 1 and May 31
Nighttime Savers Rate RPM		
On-Peak	~~$(0.151904)~~ *(0.160854)*	per Outflow kWh between June 1 and September 30
Off-Peak	~~$(0.116161)~~ *(0.121851)*	per Outflow kWh between June 1 and September 30
Super Off-Peak	~~$(0.093996)~~ *(0.098477)*	per Outflow kWh between June 1 and September 30
On-Peak	~~$(0.096396)~~ *(0.103352)*	per Outflow kWh between October 1 and May 31
Off-Peak	~~$(0.090423)~~ *(0.094453)*	per Outflow kWh between October 1 and May 31
Super Off-Peak	~~$(0.072645)~~ *(0.076001)*	per Outflow kWh between October 1 and May 31

Secondary Rates

Rate GS		
All Hours	~~$(0.108107)~~ *(0.111498)*	per Outflow kWh during the billing months of June - September
All Hours	~~$(0.079784)~~ *(0.082246)*	per Outflow kWh during the billing months of October - May
Rate GSTU(1)		
On-Peak	~~$(0.147341)~~ *(0.151764)*	per Outflow kWh during the billing months of June - September
Mid-Peak	~~$(0.114753)~~ *(0.117984)*	per Outflow kWh during the billing months of June - September
Off-Peak	~~$(0.086122)~~ *(0.088593)*	per Outflow kWh during the billing months of June - September
On-Peak	~~$(0.087178)~~ *(0.089948)*	per Outflow kWh during the billing months of October - May
Off-Peak	~~$(0.070470)~~ *(0.072476)*	per Outflow kW during the billing months of October - May
Rate GSD(1)		
All Hours	~~$(0.032526)~~ *(0.030382)*	per Outflow kWh during the billing months of June - September
Demand	~~$(24.27)~~ *(27.71)*	per Outflow kW during the billing months of June - September
All Hours	~~$(0.023861)~~ *(0.022290)*	per Outflow kWh during the billing months of October - May
Demand	~~$(19.06)~~ *(20.27)*	per Outflow kW during the billing months of October - May

(1) Outflow credit will be reduced by the applicable Interruptible Credit for GSTU and GSD customers participating on GSI Provision.

(Continued on Sheet No. C-64.40)

(Continued From Sheet No. C-64.30)

C11. SELF-GENERATION, NET METERING, DISTRIBUTED GENERATION AND SIMPLE RENEWABLE PROGRAM (Contd)

C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)

E. Customer Billing (Contd)
a. Full Service Customers Outflow Credit (Contd)
b. Retail Open Access Customers
The Outflow Credit will be determined by the Retail Service Supplier.

Primary Rates

Rate GP	Customer Voltage Level 1:	Customer Voltage Level 2:	Customer Voltage Level 3:	
Summer				
All Hours	~~$(0.094934)~~ *(0.095843)*	~~$(0.096192)~~ *(0.097105)*	~~$(0.097461)~~ *(0.098292)*	per Outflow kWh during the billing months of June - September
Winter				
All Hours	~~$(0.071132)~~ *(0.071674)*	~~$(0.072078)~~ *(0.072620)*	~~$(0.073033)~~ *(0.073510)*	per Outflow kWh during the billing months of October - May

Rate GPD[2]	Customer Voltage Level 1:	Customer Voltage Level 2:	Customer Voltage Level 3:	
Summer				
On-Peak	~~$(0.040427)~~ *(0.039617)*	~~$(0.040900)~~ *(0.040092)*	~~$(0.041312)~~ *(0.040492)*	per Outflow kWh during the billing months of June - September
Off-Peak	~~$(0.026219)~~ *(0.025470)*	~~$(0.026526)~~ *(0.025775)*	~~$(0.026793)~~ *(0.026033)*	per Outflow kWh during the billing months of June - September
Demand	~~$(25.15)~~ *(28.14)*	~~$(25.50)~~ *(28.52)*	~~$(25.87)~~ *(28.90)*	per Outflow kW during the billing months of June - September
Winter				
On-Peak	~~$(0.025351)~~ *(0.025027)*	~~$(0.025648)~~ *(0.025327)*	~~$(0.025907)~~ *(0.025580)*	per Outflow kWh during the billing months of October - May
Off-Peak	~~$(0.022012)~~ *(0.021398)*	~~$(0.022270)~~ *(0.021655)*	~~$(0.022495)~~ *(0.021871)*	per Outflow kWh during the billing months of October - May
Demand	~~$(22.98)~~ *(25.52)*	~~$(23.30)~~ *(25.87)*	~~$(23.64)~~ *(26.20)*	per Outflow kW during the billing months of October - May

[2] For customers on Rate GPD GI Provision, On-Peak kW Outflow Credit shall be reduced by $8.50 per kW during the billing months of June through September and $7.50 per kW during the billing months of October through May.

Rate GPTU	Customer Voltage Level 1:	Customer Voltage Level 2:	Customer Voltage Level 3:	
Summer				
High-Peak	~~$(0.128006)~~ *(0.137723)*	~~$(0.129695)~~ *(0.139530)*	~~$(0.131391)~~ *(0.141224)*	per Outflow kWh between June 1 and September 30
Mid-Peak	~~$(0.113945)~~ *(0.121953)*	~~$(0.115450)~~ *(0.123554)*	~~$(0.116959)~~ *(0.125057)*	per Outflow kWh between June 1 and September 30
Low-Peak	~~$(0.091964)~~ *(0.098335)*	~~$(0.093177)~~ *(0.099626)*	~~$(0.094395)~~ *(0.100838)*	per Outflow kWh between June 1 and September 30
Off-Peak	~~$(0.113945)~~ *(0.073242)*	~~$(0.115450)~~ *(0.074204)*	~~$(0.116959)~~ *(0.075107)*	per Outflow kWh between June 1 and September 30
Winter				
High-Peak	~~$(0.082444)~~ *(0.090684)*	~~$(0.083531)~~ *(0.091872)*	~~$(0.084624)~~ *(0.092984)*	per Outflow kWh between October 1 and May 31
Mid-Peak	~~$(0.076380)~~ *(0.082162)*	~~$(0.077388)~~ *(0.083241)*	~~$(0.078399)~~ *(0.084251)*	per Outflow kWh between October 1 and May 31
Off-Peak	~~$(0.063823)~~ *(0.068034)*	~~$(0.064664)~~ *(0.068928)*	~~$(0.065509)~~ *(0.069765)*	per Outflow kWh between October 1 and May 31

Rate EIP	Customer Voltage Level 1:	Customer Voltage Level 2:	Customer Voltage Level 3:	
Summer				
High-Peak	~~$(0.120841)~~ *(0.129727)*	~~$(0.122413)~~ *(0.131412)*	~~$(0.122413)~~ *(0.132974)*	per Outflow kWh between June 1 and September 30
Mid-Peak	~~$(0.108020)~~ *(0.115594)*	~~$(0.109424)~~ *(0.117095)*	~~$(0.110812)~~ *(0.118487)*	per Outflow kWh between June 1 and September 30
Low-Peak	~~$(0.086392)~~ *(0.092687)*	~~$(0.087515)~~ *(0.093892)*	~~$(0.088627)~~ *(0.095008)*	per Outflow kWh between June 1 and September 30
Off-Peak	~~$(0.063874)~~ *(0.067829)*	~~$(0.064706)~~ *(0.068712)*	~~$(0.065530)~~ *(0.069532)*	per Outflow kWh between June 1 and September 30
Critical Peak	~~$(0.181262)~~ *(0.194589)*	~~$(0.183620)~~ *(0.197117)*	~~$(0.185950)~~ *(0.199461)*	per Outflow kWh between June 1 and September 30
Winter				
High-Peak	~~$(0.076533)~~ *(0.084284)*	~~$(0.077531)~~ *(0.085378)*	~~$(0.078519)~~ *(0.086392)*	per Outflow kWh between October 1 and May 31
Mid-Peak	~~$(0.071290)~~ *(0.076539)*	~~$(0.072218)~~ *(0.077534)*	~~$(0.073138)~~ *(0.078458)*	per Outflow kWh between October 1 and May 31
Off-Peak	~~$(0.059655)~~ *(0.063597)*	~~$(0.072218)~~ *(0.064424)*	~~$(0.061200)~~ *(0.065191)*	per Outflow kWh between October 1 and May 31
Critical Peak	~~$(0.114801)~~ *(0.126426)*	~~$(0.116296)~~ *(0.128067)*	~~$(0.117778)~~ *(0.129587)*	per Outflow kWh between October 1 and May 31

~~**(Continued on Sheet No. C-64.50)**~~

~~**(Continued From Sheet No. C-64.40)**~~

This sheet has been cancelled and is reserved for future use.

(Continued on Sheet No. C-64.60)

(Continued From Sheet No. C-76.00)

C18. STANDARD OFFER - PURCHASED POWER (Contd)

D. Monthly Rate (Contd)

Rate Options (Contd)

Capacity

The monthly capacity payment will be equal to the number of Zonal Resource Credits ("ZRCs") that MISO determines the seller's QF can supply to the Company for the applicable MISO resource planning period multiplied by the applicable capacity rate expressed in such units of capacity. The current resource planning period is the planning year which runs from June 1st of each year through May 31st of the following year. If no historical generation data is available for the first year of generation a QF shall be assigned the MISO class average capacity credits by technology.

Capacity value paid to QFs does not depend on whether the Company actually obtains ZRCs for such capacity, only that the Company could obtain ZRCs for the QF capacity. Capacity value paid to a QF is in units of $ per ZRC-Month. MISO ZRCs are equal to the project's nameplate capacity (in MW_{AC}) modified by the MISO effective load carrying capacity (ELCC) calculation.

Capacity will be paid based on the average of the methodologies utilized by MISO at the time the QF contract is executed and at the time of capacity delivery from the QF, according to the MISO Business Practices Manual (BPM) calculation method effective at the respective times.

Eligible QFs that meet the requirements of Section C18A (1) or C18A (2) of this Rule can select one of the Energy Rate Options listed below:

Rate Option	**Energy Rate $/kWh**			
1. As Available Rate	Actual MISO Day Ahead Locational Marginal Price (LMP) at the Company's CONS.CETR load node under a 15-year term then multiplied by 1 plus the line loss adjustment factor of ~~2.24~~ *2.22*% for interconnection voltages less than 46 kV or ~~1.36~~ *1.32*% for interconnection voltage at 46 kV and less the Administrative Fee of $0.001/kWh			
2. LMP Energy Rate Forecast (Year 1-5)	A 10-year term based on a forecast of LMPs for the first five years and year six through year 10 of the term will be based on actual LMPs as described below. Rates include the line loss adjustment and Administrative Fee.			
	On-Peak Energy Rate Interconnection Voltage <46 kV	**Off-Peak Energy Rate Interconnection Voltage <46 kV**	**On-Peak Energy Rate Interconnection Voltage =46 kV**	**Off-Peak Energy Rate Interconnection Voltage =46 kV**
Year	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
2025	$0.03148	$0.02648	$0.03117	$0.02621
2026	$0.03296	$0.02757	$0.03263	$0.02729
2027	$0.03458	$0.02865	$0.03423	$0.02836
2028	$0.03530	$0.02876	$0.03495	$0.02847
2029	$0.03624	$0.02975	$0.03588	$0.02945
2030	$0.03727	$0.03052	$0.03690	$0.03021
2031	$0.03765	$0.03131	$0.03728	$0.03100
2032	$0.03836	$0.03209	$0.03798	$0.03177
2033	$0.04007	$0.03306	$0.03968	$0.03273
Actual LMP (Year 6-10)	Actual MISO Day Ahead Locational Marginal Price (LMP) at the Company's CONS.CETR load node under the remaining contract term then multiplied by 1 plus the line loss adjustment factor of ~~2.24~~ *2.22*% for interconnection voltages less than 46 kV or ~~1.36~~ *1.32*% for interconnection voltage at 46 kV and less the Administrative Fee of $0.001/kWh.			

(Continued on Sheet No. C-78.00)

(Continued From Sheet No. C-78.00)

C19. TRANSPORTATION ELECTRIFICATION PROGRAMS (TEPS)

The Company's Transportation Electrification Programs (TEPs) have been created to support the development of infrastructure within the Company's service territory needed to accommodate widespread adoption of electric vehicles (EVs) and help optimize use of the grid. TEPs will also increase battery and plug-in hybrid electric vehicle (EV) charging capabilities and charging infrastructure across the state, while improving off-peak utilization of the electric grid to benefit all electric customers. Eligible customers who participate in these programs may receive a rebate incentive for optimizing use of their electric vehicle supply equipment (EVSE) to help reduce the cost of make-ready infrastructure and EVSE ~~but the EVSE must be separately metered from all other electrical load and used for the exclusive purpose of charging electric vehicle batteries~~.

Customers not participating in TEPs that still want to install EVSE at their premises may select a Rate Schedule commensurate with their Non-Residential or Residential usage as applicable but may incur additional costs due to co-incident peak usage of their EVSE, exceeding design standards, or both.

C19.1 Residential Electric Vehicle Programs

A. Definitions

(1) "AMI Monitoring" means advanced metering infrastructure monitoring which stores, tracks, and communicates usage data with the Company.

(2) "Electric Vehicle" means a motorized vehicle that has a battery instead of a gasoline tank, and an electric motor instead of an internal combustion engine. For purposes of the Residential Electric Vehicle Program, the term shall also include Plug-in hybrid electric vehicles (PHEVs), which are a combination of gasoline and electric vehicles. In addition to a plug-in battery, such vehicles have an electric motor, a gasoline tank and an internal combustion engine.

(3) "Electric Vehicle Charging Outlet" means a NEMA 14-50 outlet, or other similar technology subject to the sole discretion and approval of the Company.

B. ~~On-Bill Installment Payment Plan and~~ *PowerMIDrive* Rebate ~~Qualifications~~ for Electric Vehicle Charging Outlet Installation

(1) Eligibility

Residential Customers ~~taking service on Residential Smart Hours Rate RSH or Residential Nighttime Savers Rate RPM may be eligible for the On-Bill Installment Payment Plan to pay for the cost of installation of an~~ *installing an* Electric Vehicle Charging Outlet~~and~~ may ~~also~~ be eligible for a one-time initial rebate of up to $500 to offset installation charges. Residential Customers ~~taking service on Residential Smart Hours Rate RSH or Residential Nighttime Savers Rate RPM~~ who meet the eligibility criteria of the Income Assistance Service Provision or the Low Income Assistance Credit may qualify for a one-time initial rebate of up to $1000 to offset installation charges in lieu of the standard initial rebate of $500.

Multifamily Dwellings containing four or fewer households served through a single meter ~~taking service on Residential Smart Hours Rate RSH or Residential Nighttime Savers Rate RPM may be eligible for the On-Bill Installment Payment Plan to pay for the cost of installation of an~~ *and are installing an* Electric Vehicle Charging Outlet~~and~~ may be eligible for a one-time initial rebate of up to $500 to offset installation charges. If the existing single meter of the Multifamily Dwelling cannot serve the parking area of the dwelling, the premises may be eligible for an enhanced rebate of up to $7500 for installation of at least two Electric Vehicle Charging Outlets or hard-wired chargers rated at 50 amps.

Residential Customers interested in the *PowerMIDrive rebate* ~~On-Bill Installment Payment Plan~~ shall submit an online application *on the Company's website* to determine eligibility. ~~Eligible customers shall select an installer from a list of Company pre-approved installers, using the Company's website, to install the Electric Vehicle Charging Outlet at the eligible address.~~ The Electric Vehicle Charging Outlet shall be installed at the address displayed on the registration of the Electric Vehicle, which must be the Principal Residence of the customer. ~~In the event the customer fails to utilize a pre-approved installer set forth on Company's website, eligibility to participate in the On-Bill Installment Payment Plan may be revoked, which may result in the customer paying the installer directly and forfeiting the benefits associated with the On-Bill Installment Payment Plan.~~ *Customers taking service on Residential Service Secondary Non-Transmitting Meter Rate RSM are not eligible for the PowerMIDrive rebate.*

(Continued on Sheet No. C-80.00)

(Continued From Sheet No. C-79.00)

C19. TRANSPORTATION ELECTRIFICATION PROGRAMS (TEPS) (Contd)

C19.1 Residential Electric Vehicle Programs (Contd)

B. ~~On-Bill Installment Payment Plan and~~ *PowerMIDrive* Rebate Qualifications for Electric Vehicle Charging Outlet Installation (Contd)

(1) Eligibility (Contd)

~~At the Company's sole discretion, eligible~~ Residential Customers may *apply for the PowerMIDrive rebate* ~~enroll in the On-Bill Installment Payment Plan~~ prior to receipt of a valid State-issued Electric Vehicle registration if the customer has proof of an existing reservation for an Electric Vehicle. ~~In the event that a customer is enrolled in the On-Bill Installment Payment Plan under the program and an Electric Vehicle Charging Outlet is installed pursuant to said approval, but the customer fails to ultimately obtain an Electric Vehicle or otherwise provide proof of a valid State-issued Electric Vehicle registration, the customer's eligibility to participate in the On-Bill Installment Payment Plan may be revoked, and the customer may be required to pay the full cost of the Electric Vehicle Charging Outlet and its installation without the benefit provided for under the On-Bill Installment Payment Plan.~~

~~(2) On-Bill Installment Payment Plan~~

~~The On-Bill Installment Payment Plan Monthly Amount is calculated as the total of installation fee of the selected pre-approved installer plus a $10 one-time administrative fee less an eligible rebate divided by 12. The On-Bill Installment Payment Plan will be billed on the customer invoices within 45 days following completion of the installation.~~

~~The On-Bill Installment Payment will appear as a separate line item on the customer invoice for 12 billing months. Customers may pay the entirety of the On-Bill Installment Plan in less than 12 months without penalty.~~

~~A participating customer shall agree to the On-Bill Installment Payment Plan Monthly Amount and repayment terms.~~

~~If a Customer enrolls in the On-Bill Installment Payment Plan prior to receipt of the Electric Vehicle, the Customer shall notify the Company upon arrival of the Electric Vehicle. Upon notification, the Customer will be enrolled in AMI Monitoring.~~

~~Participation in the On-Bill Installment Payment Plan is at the sole discretion of the Company. A customer who received a shutoff notice within the nine months preceding the Customer's request to be enrolled in the Residential Electric Vehicle Program is not eligible.~~

~~If during the duration of the approved On-Bill Installment Payment Plan, the customer, for any reason, no longer owns an Electric Vehicle, the customer shall remain responsible for the full payment due under the On-Bill Installment Payment Plan until the cost of the Electric Vehicle Charging Outlet and installation are paid in full.~~

~~If the customer sells the premises where the Electric Vehicle Charging Outlet was installed, and that customer also participates in the On-Bill Installment Payment Plan, the Customer shall notify the Company of the sale, and the full amount due and owing for the Electric Vehicle Charging Station and installation shall be accelerated and the full amount due and owing included on the Customer's final bill.~~

~~(3)~~*(2)* AMI Monitoring for ~~On-Bill Installment Payment Plan and~~ *PowerMIDrive* Rebate Participants

All Customers participating in the ~~On-Bill Installment Payment Plan,~~ *PowerMIDrive* rebate~~, or both~~ shall be enrolled in AMI Monitoring and may earn one AMI Monitoring Credit per billing month to encourage Electric Vehicle charging during Off-Peak Hours. The AMI Monitoring Credit for standard Residential ~~and Multifamily Dwelling~~ customers is $10 per billing month. ~~The AMI Monitoring Credit for enhanced Multifamily Dwelling customers is $20 per billing month.~~ The AMI Monitoring Credit shall be applied in billing months in which the customer has charged the Electric Vehicle on three or less days during On-Peak hours. The credit is available for a period of 12 consecutive months and will appear as a separate line item on the customer invoice.

Residential Customers ~~taking service on Residential Smart Hours Rate RSH or Residential Nighttime Savers Rate RPM~~ may enroll in AMI Monitoring without *applying for the PowerMIDrive rebate.* ~~enrolling in the On-Bill Installment Payment Plan.~~ Interested ~~Residential~~ Customers shall submit an online application on the Company's website to enroll in AMI Monitoring.

Customers taking service on Residential Service Secondary Non-Transmitting Meter Rate RSM are not eligible for AMI Monitoring.

(Continued on Sheet No. C-81.00)

(Continued From Sheet No. C-80.00)

C19. TRANSPORTATION ELECTRIFICATION PROGRAMS (TEPS) (Contd)

~~C19.1 Residential Electric Vehicle Programs (Contd)~~

~~B. On-Bill Installment Payment Plan and Rebate Qualifications for Electric Vehicle Charging Outlet Installation (Contd)~~

~~(3) AMI Monitoring for On-Bill Installment Payment Plan and Rebate Participants (Contd)~~

~~Customers participating in AMI Monitoring may earn one $10 AMI Monitoring Credit per participating Electric Vehicle per billing month to encourage Electric Vehicle charging during Off-Peak hours. The AMI Monitoring Credit shall be applied in billing months in which the customer has charged the Electric Vehicle on three or less days during On-Peak Hours. The AMI Monitoring Credit is available for a period of 12 consecutive months and will appear as a separate line item on the customer invoice.~~

C19.2. Non-Residential Electric Vehicle Programs

A. PowerMIDrive Public

(1) Eligibility

This program is available to any Non-Residential Customer, either Full Service or Retail Open Access (ROA), that installs a Company-qualified Level 2 or Level 1 electric vehicle supply equipment (EVSE) at ~~a~~ qualifying ~~overnight or long-term parking~~ locations available to the public. ~~These are, but not limited to, the following locations: hotels, motels, campgrounds, resorts, airports, train stations and other locations in which the general public can park their electric vehicle overnight or multiple days while charging.~~ Customers who participate in this program may be eligible for a rebate per the terms and conditions located on the Company's website.

Such EVSE must be UL or equivalent safety certified *and* Energy Star rated ~~and achieve at least a 97% up-time for five years after installation~~. *For parking lots with greater than 10 parking spaces, the EVSE must be separately metered from all other electrical load and used for the exclusive purpose of charging electric vehicle batteries*. The EVSE operator may determine the pricing structure and this is not considered Resale. The site must also include clear signage that parking is for EV charging only.

(2) Terms and Conditions

To participate in the program, the customer must comply with all terms and conditions as stated on the Company's website. Applications are not a guarantee of program acceptance or rebate payment. Completed applications will be reviewed in the order received. Rebate funds are reserved for an applicant's project when Consumers Energy sends notice of acceptance to the applicant.

Full-Service Customers *that are separately metered* must be served on either General Service Secondary Time-of-Use Rate GSTU or General Service Primary Time-of-Use Rate GPTU.

For ROA Secondary Customers who choose to participate in the PowerMIDrive Public program, the distribution charges assessed to these customers will be the same as Full-Service customers being served on General Service Secondary Rate GS. ROA Primary Customers will be assessed the same distribution charges as Full-Service customers being served on as Large General Service Primary Demand Rate GPD, but must encourage charging per off-peak hours listed in GSTU or GPTU.

~~For both Full-Service and ROA customers who own and operate a DC Fast Charging station and participate in the remaining PowerMIDrive DC Fast Charging rebates, they must be served on General Service Primary Rate GP.~~

(Continued on Sheet No. C-82.00)

(Continued From Sheet No. C-81.00)

C19. TRANSPORTATION ELECTRIFICATION PROGRAMS (TEPS) (Contd)

C19.2 Non-Residential Electric Vehicle Programs (Contd)

B. PowerMIFleet

(1) Eligibility

This program is available to any Non-Residential Customer, either Full Service or Retail Open Access, that offer separately metered EVSE for private businesses and their vehicle fleet. These are, but not limited to, the following locations: public transit, non-profit organizations, local governments, small to medium sized businesses and educational facilities. Customers who are selected by the Company to participate in this program may be eligible for a rebate per the terms and conditions located on the Company's website. Such EVSE must be UL or equivalent safety certified~~,~~ *and* Energy Star rated ~~and achieve at least a 97% up-time for five years after installation~~. The EVSE operator may determine the pricing structure and this is not considered Resale.

(2) Terms and Conditions

To participate in the program, the customer must comply with all terms and conditions as stated on the Company's website. Submitting an interest form is not a guarantee of program selection for participation in the program.

Full-Service Customers *that are separately metered* shall be served on General Service Secondary Time-of-Use Rate GSTU or General Service Primary Time-of-Use Rate GPTU.

For ROA Customers who choose to participate in the PowerMIFleet program, the distribution charges assessed to these customers will be the same as Full-Service customers being served on General Service Secondary Rate GS. ROA Primary Customers will be assessed the same distribution charges as Full-Service customers being served on Large General Service Primary Demand Rate GPD but must encourage charging per off-peak hours listed in GSTU or GPTU.

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-2.20**

SURCHARGES

Rate Schedule	Electric Rate Case Demand Response Surcharge (Case No. U-21870) Effective for service rendered ~~on and after~~ May 1, 2026 *through April 30, 2027*
Rate RSP	$0.002224/kWh
Rate REH	*0.002224/kWh*
Rate RSH	0.002224/kWh
Rate RPM	0.002224/kWh
Rate RSM	0.002224/kWh
Rate GS	0.002000/kWh
Rate GSTU	0.002000/kWh
Rate GSD	0.67/kW
Rate GP	
Customer Voltage Level 1	0.001705/kWh
Customer Voltage Level 2	0.001725/kWh
Customer Voltage Level 3	0.001743/kWh
Rate GPD	
Customer Voltage Level 1	0.74/kW
Customer Voltage Level 2	0.76/kW
Customer Voltage Level 3	0.77/kW
Rate GPTU	
Customer Voltage Level 1	0.001519/kWh
Customer Voltage Level 2	0.001537/kWh
Customer Voltage Level 3	0.001552/kWh
Rate EIP	
Customer Voltage Level 1	0.001274/kWh
Customer Voltage Level 2	0.001290/kWh
Customer Voltage Level 3	0.001302/kWh
Rate LED	
Customer Voltage Level 1	NA
Customer Voltage Level 2	NA
Customer Voltage Level 3	NA
Rate LTILRR	NA
Rate GSG-2	
Customer Voltage Level 1	NA
Customer Voltage Level 2	NA
Customer Voltage Level 3	NA
Rate GML	0.000517/kWh
Rate GUL	0.000487/kWh
Rate GUL-LED	0.000487/kWh
Rate GU	0.001317/kWh
Rate PA	NA
Rate ROA-R	NA
Rate ROA-S	NA
Rate ROA-P	NA

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-2.40**

SURCHARGES

Rate Schedule	Investment Recovery Mechanism (IRM) (Case No. U-21870) Effective for service rendered May 1, 2026 through April 30, 2027	*Investment Recovery Mechanism (IRM) (Case No. U-22070) Effective for service rendered XXXXXX XX, 2027 through April 30, 2028*
Rate RSP	$0.000699/kWh	*$0.001021/kWh*
Rate REH	*0.000699/kWh*	*0.001021/kWh*
Rate RSH	0.000699/kWh	*0.001021/kWh*
Rate RPM	0.000699/kWh	*0.001021/kWh*
Rate RSM	0.000699/kWh	*0.001021/kWh*
Rate GS	0.000534/kWh	*0.000794/kWh*
Rate GSTU	0.000534/kWh	*0.000794/kWh*
Rate GSD	0.000412/kWh	*0.000603/kWh*
Rate GP		
Customer Voltage Level 1	0.000066/kWh	*0.000112/kWh*
Customer Voltage Level 2	0.000101/kWh	*0.000157/kWh*
Customer Voltage Level 3	0.000173/kWh	*0.000268/kWh*
Rate GPD		
Customer Voltage Level 1	0.000045/kWh	*0.000076/kWh*
Customer Voltage Level 2	0.000069/kWh	*0.000107/kWh*
Customer Voltage Level 3	0.000118/kWh	*0.000182/kWh*
Rate GPTU		
Customer Voltage Level 1	0.000045/kWh	*0.000076/kWh*
Customer Voltage Level 2	0.000069/kWh	*0.000107/kWh*
Customer Voltage Level 3	0.000118/kWh	*0.000182/kWh*
Rate EIP		
Customer Voltage Level 1	0.000045/kWh	*0.000076/kWh*
Customer Voltage Level 2	0.000069/kWh	*0.000107/kWh*
Customer Voltage Level 3	0.000118/kWh	*0.000182/kWh*
Rate LED		
Customer Voltage Level 1	0.000045/kWh	*0.000076/kWh*
Customer Voltage Level 2	0.000069/kWh	*0.000107/kWh*
Customer Voltage Level 3	0.000118/kWh	*0.000182/kWh*
Rate LTILRR	NA	*NA*
Rate GSG-2		
Customer Voltage Level 1	0.000045/kWh	*0.000076/kWh*
Customer Voltage Level 2	0.000069/kWh	*0.000107/kWh*
Customer Voltage Level 3	0.000118/kWh	*0.000182/kWh*
Rate GML	0.000806/kWh	*0.001146/kWh*
Rate GUL	0.003580/kWh	*0.005025/kWh*
Rate GU-LED	0.003580/kWh	*0.005025/kWh*
Rate GU	0.000203/kWh	*0.000339/kWh*
Rate PA	NA	*NA*
Rate ROA-R	Same as Full Service Delivery Schedule	*Same as Full Service Delivery Schedule*
Rate ROA-S	Same as Full Service Delivery Schedule	*Same as Full Service Delivery Schedule*
Rate ROA-P	Same as Full Service Delivery Schedule	*Same as Full Service Delivery Schedule*

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-5.00**

SURCHARGES

Rate Schedule	Electric Rate Case Deferral Surcharge (Case No. U-21870) Effective for service rendered May 1, 2026 through April 30, 2027	*Electric Rate Case Deferral Surcharge (Case No. U-22070) Effective for service rendered XXXXXX XX, 2027 through April 30, 2028*
Rate RSP	$0.001221/kWh	*$0.001262/kWh*
Rate REH	*0.001221/kWh*	*0.001262/kWh*
Rate RSH	0.001221/kWh	*0.001262/kWh*
Rate RPM	0.001221/kWh	*0.001262/kWh*
Rate RSM	0.001221/kWh	*0.001262/kWh*
Rate GS	0.000933/kWh	*0.000982/kWh*
Rate GSTU	0.000933/kWh	*0.000982/kWh*
Rate GSD	0.000720/kWh	*0.000746/kWh*
Rate GP		
Customer Voltage Level 1	0.000116/kWh	*0.000138/kWh*
Customer Voltage Level 2	0.000178/kWh	*0.000194/kWh*
Customer Voltage Level 3	0.000305/kWh	*0.000330/kWh*
Rate GPD		
Customer Voltage Level 1	0.000078/kWh	*0.000094/kWh*
Customer Voltage Level 2	0.000120/kWh	*0.000132/kWh*
Customer Voltage Level 3	0.000205/kWh	*0.000225/kWh*
Rate GPTU		
Customer Voltage Level 1	0.000078/kWh	*0.000094/kWh*
Customer Voltage Level 2	0.000120/kWh	*0.000132/kWh*
Customer Voltage Level 3	0.000205/kWh	*0.000225/kWh*
Rate EIP		
Customer Voltage Level 1	0.000078/kWh	*0.000094/kWh*
Customer Voltage Level 2	0.000120/kWh	*0.000132/kWh*
Customer Voltage Level 3	0.000205/kWh	*0.000225/kWh*
Rate LED		
Customer Voltage Level 1	0.000078/kWh	*0.000094/kWh*
Customer Voltage Level 2	0.000120/kWh	*0.000132/kWh*
Customer Voltage Level 3	0.000205/kWh	*0.000225/kWh*
Rate LTILRR	NA	*NA*
Rate GSG-2		
Customer Voltage Level 1	0.000078/kWh	*0.000094/kWh*
Customer Voltage Level 2	0.000120/kWh	*0.000132/kWh*
Customer Voltage Level 3	0.000205/kWh	*0.000225/kWh*
Rate GML	0.001409/kWh	*0.001417/kWh*
Rate GUL	0.006253/kWh	*0.006210/kWh*
Rate GU-LED	0.006253/kWh	*0.006210/kWh*
Rate GU	0.000402/kWh	*0.000419/kWh*
Rate PA	NA	*NA*
Rate ROA-R	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Schedule*
Rate ROA-S	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Schedule*
Rate ROA-P	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Schedule*
Rate ROA-GPD	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Schedule*

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-9.00**

RATE CATEGORIES AND PROVISIONS

Description	Full Service	Retail Open Access
RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP		
Residential	1001	Not Applicable
Provisions		
Residential Summer On-Peak Basic With Income Assistance (RIA) *	Applicable	Not Applicable
Residential Summer On-Peak Basic With Low Income Assistance Credit (LIAC) *	Applicable	Not Applicable
Residential Summer On-Peak Basic With Senior Citizen (RSC) *	Applicable	Not Applicable
Device Cycling Program ***	Applicable	Not Applicable
Peak Reward ***	Applicable	Not Applicable
Critical Peak Pricing ***	Applicable	Not Applicable
Residential Summer On-Peak Basic With Self-Generation (SG) **	1700	Not Applicable
Net Metering Program	Applicable	Not Applicable
Distributed Generation Program	Applicable	Not Applicable
Green Generation Program ****	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
RESIDENTIAL ELECTRIC HEATING RATE REH		
Residential	*XXXX*	*Not Applicable*
Provisions		
*Residential Electric Heating With Income Assistance (RIA) ****	*Applicable*	*Not Applicable*
*Residential Electric Heating With Low Income Assistance Credit (LIAC) ****	*Applicable*	*Not Applicable*
*Residential Electric Heating With Senior Citizen (RSC) ****	*Applicable*	*Not Applicable*
Residential Electric Heating - Plug-In Electric Vehicle Only Credit	*Applicable*	*Not Applicable*
*Device Cycling Program ******	*Applicable*	*Not Applicable*
*Peak Reward ******	*Applicable*	*Not Applicable*
*Critical Peak Pricing ******	*Applicable*	*Not Applicable*
*Residential Electric Heating With Self-Generation (SG) *****	*XXXX*	*Not Applicable*
Net Metering Program	*Applicable*	*Not Applicable*
Distributed Generation Program	*Applicable*	*Not Applicable*
*Green Generation Program *******	*Applicable*	*Not Applicable*
Renewable Energy Credit (REC) Programs	*Applicable*	*Not Applicable*
Residential Electric Vehicle Program	*Applicable*	*Not Applicable*
RESIDENTIAL SMART HOURS RATE RSH		
Residential	1040	Not Applicable
Provisions		
Residential Smart Hours With Income Assistance (RIA) *	Applicable	Not Applicable
Residential Smart Hours With Low Income Assistance Credit (LIAC) *	Applicable	Not Applicable
Residential Smart Hours With Senior Citizen (RSC) *	Applicable	Not Applicable
Device Cycling Program ***	Applicable	Not Applicable
Peak Reward ***	Applicable	Not Applicable
Critical Peak Pricing ***	Applicable	Not Applicable
Residential Smart Hours With Self-Generation (SG) **	1702	Not Applicable
Net Metering Program	Applicable	Not Applicable
Distributed Generation Program	Applicable	Not Applicable
Green Generation Program ****	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Residential Electric Vehicle Program	Applicable	Not Applicable
RESIDENTIAL NIGHTTIME SAVERS RATE RPM		
Residential	1050	Not Applicable
Provisions		
Residential Nighttime Savers With Income Assistance (RIA) *	Applicable	Not Applicable
Residential Nighttime Savers With Low Income Assistance Credit (LIAC) *	Applicable	Not Applicable
Residential Nighttime Savers With Senior Citizen (RSC) *	Applicable	Not Applicable
Residential Nighttime Savers - Plug-In Electric Vehicle Only Credit	Applicable	Not Applicable
Device Cycling Program ***	Applicable	Not Applicable
Peak Reward ***	Applicable	Not Applicable
Critical Peak Pricing ***	Applicable	Not Applicable
Residential Nighttime Savers With Self-Generation (SG) **	1703	Not Applicable
Net Metering Program	Applicable	Not Applicable
Distributed Generation Program	Applicable	Not Applicable
Green Generation Program ****	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Residential Electric Vehicle Program	Applicable	Not Applicable

* Provisions shall not be taken in conjunction with each other.
** Provisions shall not be taken in conjunction with the Net Metering Program or the Distributed Generation Program.
*** Peak Reward and/or Device Cycling Program shall not be taken in conjunction with Critical Peak Pricing.
**** Closed to new customers, effective April 5, 2019.

(Continued on Sheet No. D-10.00)

See Grondin Testimony, Page 7, Lines 10-17; Exhibit A-120 (BAG-1), Item No. 1

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-10.00**

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-9.00)

Description	Full Service	Retail Open Access
RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM		
Residential	1000	Not Applicable
Provisions		
Residential Non-Transmitting Meter With Income Assistance (RIA) *	Applicable	Not Applicable
Residential Non-Transmitting Meter With Low Income Assistance Credit (LIAC) *	Applicable	Not Applicable
Residential Non-Transmitting Meter With Senior Citizen (RSC) *	Applicable	Not Applicable
Green Generation Program ****	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
GENERAL SERVICE SECONDARY RATE GS		
Commercial	1100	2100
Commercial - Temporary Construction Service	1999	Not Applicable
Provisions		
Commercial Billboards/Outdoor Advertising Signs - Dusk to Dawn	Applicable	Not Applicable
Commercial Billboards/Outdoor Advertising Signs - Fixed Hours of Operation	Applicable	Not Applicable
Commercial Miscellaneous	Applicable	Not Applicable
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG) *	1715	Not Applicable
Net Metering Program	Applicable	Applicable
Distributed Generation Program	Applicable	Applicable
Demand Response Program	Applicable	Not Applicable
Green Generation Program **	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Non-Residential Electric Vehicle Programs	Not Applicable	Applicable
GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU		
Commercial	1121	Not Applicable
Provisions		
Commercial With Educational Institution (GEI)	Applicable	Not Applicable
Commercial With Interruptible Provision (GSI)	Applicable	Not Applicable
Commercial With Self-Generation (SG) *	1716	Not Applicable
Distributed Generation Program	Applicable	Applicable
Demand Response Program	Applicable	Not Applicable
Commercial Resale	Applicable	Not Applicable
Green Generation Program **	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable
Non-Residential Electric Vehicle Programs	Applicable	Not Applicable
GENERAL SERVICE SECONDARY DEMAND RATE GSD		
Commercial	1120	2120
Commercial (100 kW Billing Demand Guarantee)	1140	2140
Provisions		
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Interruptible Provision (GSI)	Applicable	Not Applicable
Commercial With Self-Generation (SG) *	1725	Not Applicable
Commercial (100 kW Billing Demand Guarantee) With Self-Generation (SG) *	1735	Not Applicable
Net Metering Program	Applicable	Applicable
Distributed Generation Program	Applicable	Applicable
Demand Response Program	Applicable	Not Applicable
Green Generation Program **	Applicable	Not Applicable
Renewable Energy Credit (REC) Programs	Applicable	Not Applicable

* Provisions shall not be taken in conjunction with the Net Metering Program or Distributed Generation Program.
** Closed to new customers, effective April 5, 2019.
***** Closed to new customers, effective April 5, 2019.*

(Continued on Sheet No. D-11.00)

See Gray Testimony, Page 11, Lines 1-4; Exhibit A-120 (BAG-1), Item No. 1

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-14.00**

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

Availability

Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purpose of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 - Non-Transmitting Meter Provision participants.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

Non-Capacity	Capacity	Total	
$0.077148 ~~$0.067348~~	*$0.031811* ~~$0.036622~~	*$0.108959* ~~$0.103970~~	per kWh for Off-Peak kWh between June 1 and September 30
$0.114377 ~~$0.098398~~	*$0.046477* ~~$0.053506~~	*$0.160854* ~~$0.151904~~	per kWh for On-Peak kWh between June 1 and September 30
$0.061784 ~~$0.053762~~	*$0.025394* ~~$0.029234~~	*$0.087178* ~~$0.082996~~	per kWh for all kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:	$8.00	per customer per month
Distribution Charge:	~~$0.093333~~ *0.110796*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10

(Continued on Sheet No. D-15.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-15.00**

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $~~(8.00)~~ *(12.00)* per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(42.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) and shall not be applied to more than one account per Principal Residence Customer.

(Continued on Sheet No. D-16.00)

See Gray Testimony, Page 3, Lines 13-15; Exhibit A-120 (BAG-1), Item No. 13; Exhibit A-16 (MCG-3), Pages 1-24

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-16.00)

Monthly Rate (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31 and up to five critical peak events between September 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. ~~Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event.~~ Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$(0.50)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and August 31
Off-Peak Discount:	*$(0.006008)* ~~$(0.006373)~~	per kWh of Off-Peak kWh between June 1 and August 31

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

~~**(Continued on Sheet No. D-18.00)**~~

RESIDENTIAL ELECTRIC HEATING RATE REH

Availability

Subject to any restrictions, this rate is available to any Full Service Customer utilizing electric heating service for residential use, provided the required metering equipment and supporting infrastructure are installed, in the following areas: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purpose of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 - Non-Transmitting Meter Provision participants.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.077148	*$0.031811*	*$0.108959*	*per kWh for Off-Peak kWh between June 1 and September 30*
$0.114377	*$0.046477*	*$0.160854*	*per kWh for On-Peak kWh between June 1 and September 30*
$0.062316	*$0.025719*	*$0.088035*	*per kWh for the first 750 kWh between October 1 and May 31*
$0.043478	*$0.017774*	*$0.061252*	*per kWh for all kWh over 750 kWh between October 1 and May 31*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: ***These charges are applicable to Full Service Customers.***

System Access Charge:	*$8.00*	*per customer per month*
Distribution Charge:	*$0.110796*	*per kWh for all kWh*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10

(Continued on Sheet No. D-20.00)

RESIDENTIAL ELECTRIC HEATING RATE REH

(Continued From Sheet No. D-19.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. *A Home Heating Credit energy draft*
2. *State Emergency Relief*
3. *Assistance from a Michigan Energy Assistance Program (MEAP)*
4. *Medicaid*

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(12.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. *Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months*
2. *Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)*
3. *Customers who have received a Home Heating Credit energy draft*
4. *A State Emergency Relief program*
5. *Medicaid*
6. *Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.*

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(42.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: ***These charges are applicable to Full Service and Retail Open Access customers.***

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) and shall not be applied to more than one account per Principal Residence Customer.

(Continued on Sheet No. D-21.00)

RESIDENTIAL ELECTRIC HEATING RATE REH

(Continued From Sheet No. D-20.00)

Monthly Rate (Contd)

Device Cycling Program

A customer who is taking service from the Company may be eligible to participate in the Company's voluntary Device Cycling Program for load management of eligible electric equipment, including air conditioning and water heaters. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. Customer eligibility to participate is determined solely by the Company and Device Cycling Program Credits may be taken in conjunction with one another. The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company or with a contractual agreement with a landlord if the customer is not the property owner. The Company will install the required equipment at the premises which will allow load management upon signal from the Company. When load management equipment is installed at a premises, future customers will be auto-enrolled into the Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's credit earned from their incremental savings through Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service. The Company reserves the right to call test events between September 1 and May 31 for customers participating in the Device Cycling Program.

Load management may occur during the summer billing months of June through August only. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may occur on any day, during any hour, and for any length of time during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a load management event for one load management event during the June through August months in any one calendar year for the balance of the hours left in that load management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	*$(5.00)*	*per customer per month during the billing months of June - August*

(Continued on Sheet No. D-22.00)

RESIDENTIAL ELECTRIC HEATING RATE REH

(Continued From Sheet No. D-22.00)

Monthly Rate (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31 and up to five critical peak events between September 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$(0.50)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and August 31
Off-Peak Discount:	$(0.006008)	per kWh of Off-Peak kWh between June 1 and August 31

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-23.00)

RESIDENTIAL ELECTRIC HEATING RATE REH

(Continued From Sheet No. D-22.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.8., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, June 1 through September 30, including weekday holidays when applicable:

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-24.00**

These sheets have been cancelled and are reserved for future use:

~~Original Sheet No. D-20.00 is cancelled; First Revised Sheet No. D-20.00 is reserved for future use~~
~~Original Sheet No. D-21.00 is cancelled; First Revised Sheet No. D-21.00 is reserved for future use~~
~~Original Sheet No. D-22.00 is cancelled; First Revised Sheet No. D-22.00 is reserved for future use~~
~~First Revised Sheet No. D-23.00 is cancelled; Second Revised Sheet No. D-23.00 is reserved for future use~~
Original Sheet No. D-24.00 is cancelled; First Revised Sheet No. D-24.00 is reserved for future use
Original Sheet No. D-25.00 is cancelled; First Revised Sheet No. D-25.00 is reserved for future use
Original Sheet No. D-26.00 is cancelled; First Revised Sheet No. D-26.00 is reserved for future use
First Revised Sheet No. D-27.00 is cancelled; Second Revised Sheet No. D-27.00 is reserved for future use
First Revised Sheet No. D-28.00 is cancelled; Second Revised Sheet No. D-28.00 is reserved for future use
Original Sheet No. D-29.00 is cancelled; First Revised Sheet No. D-29.00 is reserved for future use
Original Sheet No. D-30.00 is cancelled; First Revised Sheet No. D-30.00 is reserved for future use
Original Sheet No. D-31.00 is cancelled; First Revised Sheet No. D-31.00 is reserved for future use
First Revised Sheet No. D-32.00 is cancelled; Second Revised Sheet No. D-32.00 is reserved for future use
Original Sheet No. D-33.00 is cancelled; First Revised Sheet No. D-33.00 is reserved for future use
Original Sheet No. D-34.00 is cancelled; First Revised Sheet No. D-34.00 is reserved for future use
First Revised Sheet No. D-35.00 is cancelled; Second Revised Sheet No. D-35.00 is reserved for future use

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-36.00**

RESIDENTIAL SMART HOURS RATE RSH

Availability

Subject to any restrictions, this rate is available to any Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, maintain and own the required equipment at the customers' premises at the Company's request. By selecting this rate schedule, the customer agrees to provide an email address. Electric consumption is billed using on-peak and off-peak periods year-round on the Residential Smart Hours Rate.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for*: (i)* resale purposes ~~or for~~*; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv)* any *other* Non-Residential usage *or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision*.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.077148* ~~$0.067348~~	*$0.031811* ~~$0.036622~~	*$0.108959* ~~$0.103970~~	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	*$0.114377* ~~$0.098398~~	*$0.046477* ~~$0.053506~~	*$0.160854* ~~$0.151904~~	per kWh for all On-Peak kWh between June 1 and September 30
Off-Peak - Winter	*$0.059486* ~~$0.052104~~	*$0.024611* ~~$0.028333~~	*$0.084097* ~~$0.080437~~	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	*$0.073858* ~~$0.062442~~	*$0.029494* ~~$0.033954~~	*$0.103352* ~~$0.096396~~	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$~~0.093333~~ *0.110796*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10

(Continued on Sheet No. D-36.10)

See Gray Testimony, Page 11, Lines 1-4; Exhibit A-120 (BAG-1), Item No. 15; Exhibit A-16 (MCG-3), Pages 1-24

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.00)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $~~(8.00)~~ *(12.00)* per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(42.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) and shall not be applied to more than one account per Principal Residence Customer.

(Continued on Sheet No. D-37.00)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-37.00)

Monthly Rate: (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31 and up to five critical peak events between September 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. ~~Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event.~~ Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$(0.50)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and August 31
Off-Peak Discount:	*$(0.006008)* ~~$(0.006373)~~	per kWh of Off-Peak kWh between June 1 and August 31

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-39.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

Availability

The Residential Nighttime Savers Rate is voluntary and available for service rendered on and after June 1, 2021 to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this program only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Super Off-Peak - Summer	*$0.069718* ~~$0.060887~~	*$0.028759* ~~$0.033109~~	*$0.098477* ~~$0.093996~~	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Summer	*$0.086310* ~~$0.075245~~	*$0.035541* ~~$0.040916~~	*$0.121851* ~~$0.116161~~	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	*$0.114377* ~~$0.098398~~	*$0.046477* ~~$0.053506~~	*$0.160854* ~~$0.151904~~	per kWh for all On-Peak kWh between June 1 and September 30
Super Off-Peak - Winter	*$0.053774* ~~$0.047057~~	*$0.022227* ~~$0.025588~~	*$0.076001* ~~$0.072645~~	per kWh for all Super Off-Peak kWh between October 1 and May 31
Off-Peak - Winter	*$0.066787* ~~$0.058573~~	*$0.027666* ~~$0.031850~~	*$0.094453* ~~$0.090423~~	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	*$0.073858* ~~$0.062442~~	*$0.029494* ~~$0.033954~~	*$0.103352* ~~$0.096396~~	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$~~0.093333~~ *0.110796*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-40.50)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $~~(8.00)~~ *(12.00)* per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(42.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

(Continued on Sheet No. D-41.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-41.00)

Monthly Rate (Contd)

Device Cycling Program (Contd)

Load management may occur during the summer months of June through August only. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may occur on any day, during any hour, and for any length of time during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a load management event for one load management event during the June through August months in any one calendar year for the balance of the hours left in that load management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers - Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(5.00)	per customer per month during the billing months of June - August

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31 and up to five critical peak events between September 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. ~~Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event.~~ Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward Enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward	$(0.50)	per kWh of incremental energy reduction during a critical peak event

(Continued on Sheet No. D-43.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-42.00)

Monthly Rate (Contd)

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company may call up to fourteen critical peak events between June 1 and August 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price	$1.00	per kWh of energy consumed during a critical peak event between June 1 and August 31
Off-Peak Discount	$~~(0.006373)~~ *(0.006008)*	per kWh for Off-Peak kWh between June 1 and August 31

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provision contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-44.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-44.10**

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

Availability

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is only available to customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision, customers with a Non-Communicating Advanced Metering Infrastructure (AMI) Meter, or customers determined to be eligible at the Company's sole discretion.

A Non-Communicating AMI meter is unable to consistently transmit interval data to the Company's billing system. Non-Communicating Meters are determined at the Company's sole discretion and are subject to a minimum of one communication review per calendar year. When the meter has been determined to successfully communicate interval data, the customer may be transferred to Residential Service Secondary On-Peak Summer Basic Rate RSP. The transfer to Rate RSP shall not occur between June 1 and September 30.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

Non-Capacity	Capacity	Total	
$0.061784 ~~$0.053762~~	*$0.025394* ~~$0.029234~~	*$0.087178* ~~$0.082996~~	per kWh for the first 600 kWh per month during the billing months of June - September
$0.114377 ~~$0.098398~~	*$0.046477* ~~$0.053506~~	*$0.160854* ~~$0.151904~~	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$0.061784 ~~$0.053762~~	*$0.025394* ~~$0.029234~~	*$0.087178* ~~$0.082996~~	per kWh for all kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-44.20)

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.10)

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$~~0.093333~~ *0.110796*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Income Assistance Service Provision (RIA)

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following in the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Income Assistance Credit:	$~~(8.00)~~ *(12.00)*	per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.
This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC)

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit:	$(42.00)	per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

(Continued on Sheet No. D-44.30)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-45.00**

GENERAL SERVICE SECONDARY RATE GS

Availability

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

Non-Capacity	Capacity	Total	
$0.082864 ~~$0.073051~~	*$0.028634* ~~$0.035056~~	*$0.111498* ~~$0.108107~~	per kWh for all kWh during the billing months of June - September
$0.061019 ~~$0.053797~~	*$0.021227* ~~$0.025987~~	*$0.082246* ~~$0.079784~~	per kWh for all kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$~~0.069433~~ *0.084400*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Billboard Service Provision

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-46.00)

See Gray Testimony, Page 3, Lines 13-15; Exhibit A-120 (BAG-1), Item No. 13; Exhibit A-16 (MCG-3), Pages 1-24

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-45.00)

Monthly Rate: (Contd)

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit: $~~(0.001000)~~ *(0.001179)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-47.00)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems. Standby service shall be provided on this rate for secondary customers with solar installations equal to or greater than 150 kW.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with Net Metering.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.065670* ~~$0.058059~~	*$0.022923* ~~$0.028063~~	*$0.088593* ~~$0.086122~~	per kWh for all Off-Peak kWh during the billing months of June - September
Mid-Peak-Summer	*$0.087460* ~~$0.077384~~	*$0.030524* ~~$0.037369~~	*$0.117984* ~~$0.114753~~	per kWh for all Mid-Peak kWh during the billing months of June - September
On-Peak-Summer	*$0.112571* ~~$0.099359~~	*$0.039193* ~~$0.047982~~	*$0.151764* ~~$0.147341~~	per kWh for all On-Peak kWh during the billing months of June - September
Off-Peak-Winter	*$0.053721* ~~$0.047509~~	*$0.018755* ~~$0.022961~~	*$0.072476* ~~$0.070470~~	per kWh for all Off-Peak kWh during the billing months of October - May
On-Peak -Winter	*$0.066727* ~~$0.058750~~	*$0.023221* ~~$0.028428~~	*$0.089948* ~~$0.087178~~	per kWh for all On-Peak kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge: $20.00 per customer per month

Distribution Charge: $~~0.069433~~ *0.084400* per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-49.00)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-48.00)

Monthly Rate (Contd)

Schedule of Hours

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year's Day - January 1, Memorial Day - Last Monday in May, Independence Day - July 4, Labor Day - First Monday in September, Thanksgiving Day - Fourth Thursday in November and Christmas Day - December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

(1)	Off-Peak Hours	12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
(2)	Mid-Peak Hours	7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
(3)	On-Peak Hours	2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

(1)	Off-Peak Hours	11:00 PM to 7:00 AM
(2)	On-Peak Hours	7:00 AM to 11:00 PM

Resale Service Provision

Subject to any restrictions, the provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service Customers.**

Education Institution Credit: $~~(0.001000)~~ *(0.001179)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

(Continued on Sheet No. D-50.00)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-49.00)

Monthly Rate (Contd)

General Service Secondary Interruptible (GSI) Provision (Contd)

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year. All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GSI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit: $~~(0.021695)~~ *(0.021742)* per kWh for all kWh

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

(Continued on Sheet No. D-50.10)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: These Charges are applicable to Full Service customers.

Peak Demand Charge:

Non-Capacity	Capacity	Total	
$19.38 ~~$14.10~~	*$8.33* ~~$10.17~~	*$27.71* ~~$24.27~~	per kW for all kW of Peak Demand during the billing months of June - September
$12.86 ~~$10.01~~	*$7.41* ~~$9.05~~	*$20.27* ~~$19.06~~	per kW for all kW of Peak Demand during the billing months of October - May

Energy Charge:

Non-Capacity

~~$0.032526~~ *0.030382* per kWh for all kWh during the billing months of June - September
~~$0.023861~~ *0.022290* per kWh for all kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factors shown on Sheet No. D-6.00.

Delivery Charges: These Charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$1.00	per kW for all kW of Peak Demand
Distribution Charge:	~~$0.057650~~ *0.068248*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-52.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-53.00**

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-52.00)

Monthly Rate (Contd)

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit: $~~(0.000820)~~ *(0.000956)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electric Procedure or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate. This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year. All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GSI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(8.50)	per kW for all kW of Peak Demand during the billing months of June - September
	$(7.50)	per kW for all kW of Peak Demand during the billing months of October - May

(Continued on Sheet No. D-53.50)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-55.00**

GENERAL SERVICE PRIMARY RATE GP

Availability

As of January 1, 2021, this rate is closed to new business other than for service to DCFC fast charging stations. Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts and where the meter is located on the Company side of the substation transformer, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service customers.

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.076253	*$0.022039*	*$0.098292*	per kWh for all kWh during the billing months
~~$0.069019~~	~~$0.028442~~	~~$0.097461~~	of June - September
$0.056699	*$0.016811*	*$0.073510*	per kWh for all kWh during the billing months
~~$0.051337~~	~~$0.021696~~	~~$0.073033~~	of October - May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.075383	*$0.021722*	*$0.097105*	per kWh for all kWh during the billing months
~~$0.068194~~	~~$0.027998~~	~~$0.096192~~	of June - September
$0.056050	*$0.016570*	*$0.072620*	per kWh for all kWh during the billing months
~~$0.050721~~	~~$0.021357~~	~~$0.072078~~	of October - May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.074429	*$0.021414*	*$0.095843*	per kWh for all kWh during the billing months
~~$0.067339~~	~~$0.027595~~	~~$0.094934~~	of June - September
$0.055340	*$0.016334*	*$0.071674*	per kWh for all kWh during the billing months
~~$0.050083~~	~~$0.021049~~	~~$0.071132~~	of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-56.00)

See Gray Testimony, Page 3, Lines 13-15; Exhibit A-120 (BAG-1), Item No. 13; Exhibit A-16 (MCG-3), Pages 1-24

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-55.00)

Monthly Rate (Contd)

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Distribution Charge: $~~0.024415~~ *0.030543* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: $~~0.010996~~ *0.013754* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: $~~0.006957~~ *0.009289* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above or below .875, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is higher than .875, a $1.14 per Kilovar credit will be applied to the amount which the average lagging Kilovar demand during the billing period is below that for an average Power Factor of .875. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .875, a per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of .875 in accordance with the following table:

Power Factor	**Penalty**
0.700 to 0.874	$1.14 per Kilovar
Below 0.700	$1.14 per Kilovar first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A $5.25 per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of 0.875, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the $5.25 per Kilovar penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-57.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-57.00**

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-56.00)

Monthly Rate (Contd)

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $~~(0.004513)~~ *(0.005083)* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(0.004093)~~ *(0.005427)* per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**
Educational Institution Credit: $~~(0.000578)~~ *(0.000649)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-58.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-59.00**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts and where the meter is located on the Company side of the substation transformer, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers

Charges for Customer Voltage Level 3 (CVL 3)

Demand Charge:

Non-Capacity	Capacity	Total	
$~~6.09~~ *9.81*	$~~10.37~~ *8.56*	$~~16.46~~ *18.37*	per kW of On-Peak Billing Demand during the billing months of June - September
$~~5.26~~ *8.47*	$~~9.62~~ *7.93*	$~~14.88~~ *16.40*	per kW of On-Peak Billing Demand during the billing months of October - May

Transmission Charge:

Non-Capacity

$~~9.41~~ *10.53*	per kW of On-Peak Billing Demand during the billing months of June - September
$~~8.76~~ *9.80*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity

$~~0.041312~~ *0.040492*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.026793~~ *0.026033*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.025907~~ *0.025580*	per kWh for all On-Peak kWh during the billing months of October - May
$~~0.022495~~ *0.021871*	per kWh for all Off-Peak kWh during the billing months of October - May

(Continued on Sheet No. D-60.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-59.00)

Monthly Rate (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Demand Charge:

Non-Capacity	Capacity	Total	
$~~6.03~~ *9.71*	$~~10.21~~ *8.43*	$~~16.24~~ *18.14*	per kW of On-Peak Billing Demand during the billing months of June - September
$~~5.21~~ *8.39*	$~~9.47~~ *7.82*	$~~14.68~~ *16.21*	per kW of On-Peak Billing Demand during the billing months of October - May

Transmission Charge:

Non-Capacity

$~~9.26~~ *10.38*	per kW of On-Peak Billing Demand during the billing months of June - September
$~~8.62~~ *9.66*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity

$~~0.040900~~ *0.040092*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.026526~~ *0.025775*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.025648~~ *0.025327*	per kWh for all On-Peak kWh during the billing months of October - May
$~~0.022270~~ *0.021655*	per kWh for all Off-Peak kWh during the billing months of October - May

Charges for Customer Voltage Level 1 (CVL 1)

Demand Charge:

Non-Capacity	Capacity	Total	
$~~5.96~~ *9.60*	$~~10.06~~ *8.31*	$~~16.02~~ *17.91*	per kW of On-Peak Billing Demand during the billing months of June - September
$~~5.15~~ *8.29*	$~~9.33~~ *7.71*	$~~14.48~~ *16.00*	per kW of On-Peak Billing Demand during the billing months of October - May

Transmission Charge:

Non-Capacity

$~~9.13~~ *10.23*	per kW of On-Peak Billing Demand during the billing months of June - September
$~~8.50~~ *9.52*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity

$~~0.040427~~ *0.039617*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.026219~~ *0.025470*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.025351~~ *0.025027*	per kWh for all On-Peak kWh during the billing months of October - May
$~~0.022012~~ *0.021398*	per kWh for all Off-Peak kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-61.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-61.00**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-60.00)

Monthly Rate (Contd)

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Distribution Charge: ~~$6.68~~ *8.12* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: ~~$3.61~~ *4.45* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: ~~$2.37~~ *3.28* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above or below .875, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is higher than .875, a $1.14 per Kilovar credit will be applied to the amount which the average lagging Kilovar demand during the billing period is below that for an average Power Factor of .875. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .875, a per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of .875 in accordance with the following table:

Power Factor	**Penalty**
0.700 to 0.874	$1.14 per Kilovar
Below 0.700	$1.14 per Kilovar first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A $5.25 per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of 0.875, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the $5.25 per Kilovar penalty applies again.

(Continued on Sheet No. D-62.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-61.00)

Monthly Rate (Contd)

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $~~(1.93)~~ *(2.16)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(1.82)~~ *(2.51)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-63.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-63.00**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-62.00)

Monthly Rate (Contd)

Aggregate Peak Demand Service Provision (GAP)

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW. Not withstanding the specific requirements outlined in this provision, the Company may, at its sole discretion, allow participation by customers who do not fully meet one or more of the stated eligibility criteria, including but not limited to the number of accounts or demand thresholds.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Educational Institution Credit: $~~(0.000205)~~ *(0.000226)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-64.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-65.00)

Monthly Rate (Contd)

Interruptible Service Provision - Market-Price Option (GI2) (Contd)

Monthly Billing

For billing purposes, the Contracted Firm Capacity will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges: These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)

LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	*$0.038856* ~~$0.033010~~	per kWh for all kWh during the billing months of June - September
	$0.036967 ~~$0.031900~~	per kWh for all kWh during the billing months of October - May

Charges for Customer Voltage Level 2 (CVL 2)

LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	*$0.035859* ~~$0.031449~~	per kWh for all kWh during the billing months of June - September
	$0.032876 ~~$0.029198~~	per kWh for all kWh during the billing months of October - May

Charges for Customer Voltage Level 1 (CVL 1)

LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	*$0.034321* ~~$0.029081~~	per kWh for all kWh during the billing months of June - September
	$0.031388 ~~$0.026985~~	per kWh for all kWh during the billing months of October - May

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~0.986~~ *0.917*%
Customer Voltage Level 2	~~1.359~~ *1.320*%	~~2.247~~ *2.220*%
Customer Voltage Level 3	~~3.268~~ *3.237*%	~~6.502~~ *7.963*%

Delivery Charges: These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge		
If contracted capacity is separately metered:	$100.00	per additional meter installation per month

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10 as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

(Continued on Sheet No. D-67.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.00)

Coincident Peak Demand Provision (CPD)

This provision is available to any customer on Rate GPD but limited to the first three customers enrolled in the provision. Customers served under this provision will be charged capacity and transmission through a volumetric on peak energy charge as stated below. This will be charged on all energy consumed during the on peak window, from 11 AM to 7 PM. They will pay the On Peak Demand Charge on all demand during the coincident peak window of 4 PM to 6 PM. Customers served under this provision will be subject to Critical Peak Event Pricing.

Critical Peak Event Determination

A Critical Peak Event occurs when a System Integrity Event is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed the full on peak demand charge plus $1.00/kWh during the duration of the event.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

Non-Capacity	Capacity	Total	
NA	*$0.034989* ~~$0.031287~~	*$0.034989* ~~$0.031287~~	per kWh of On-Peak kWh during the billing months of June - September
NA	*$0.031205* ~~$0.028277~~	*$0.031205* ~~$0.028277~~	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
~~$6.09~~ *9.81*	~~$10.37~~ *8.56*	~~$16.46~~ *18.37*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
~~$5.26~~ *8.47*	~~$9.62~~ *7.93*	~~$14.88~~ *16.40*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of October - May

Transmission Charge:

Non-Capacity

~~$0.017876~~ *0.020061*	per kWh of On-Peak kWh during the billing months of June - September
~~$0.016640~~ *0.018641*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity

~~$0.026793~~ *0.026033*	per kWh for all Off-Peak kWh during the billing months of June - September
~~$0.041312~~ *0.040492*	per kWh for all On-Peak kWh during the billing months of June - September
~~$0.022495~~ *0.021871*	per kWh for all Off-Peak kWh during the billing months of October - May
~~$0.025907~~ *0.025580*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
~~$6.09~~ *9.81*	~~$10.37~~ *8.56*	~~$16.46~~ *18.37*	per kW of On-Peak Billing Demand during a System Integrity Event during the billing months of June - September
~~$5.26~~ *8.47*	~~$9.62~~ *7.93*	~~$14.88~~ *16.40*	per kW of On-Peak Billing Demand during a System Integrity Event during the billing months of October - May
NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event

(Continued on Sheet No. D-67.20)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.10)

Monthly Rate (Contd)

Coincident Peak Demand Provision (CPD) (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Non-Capacity	Capacity	Total	
NA	*$0.032495* ~~$0.030044~~	*$0.032495* ~~$0.030044~~	per kWh of On-Peak kWh during the billing months of June - September
NA	*$0.029009* ~~$0.027129~~	*$0.029009* ~~$0.027129~~	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
~~$6.03~~ *9.71*	~~$10.21~~ *8.43*	~~$16.24~~ *18.14*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
~~$5.21~~ *8.39*	~~$9.47~~ *7.82*	~~$14.68~~ *16.21*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of October - May

Transmission Charge:

Non-Capacity

~~$0.017130~~ *0.018586*	per kWh of On-Peak kWh during the billing months of June - September
~~$0.008416~~ *0.009256*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity

~~$0.026526~~ *0.025775*	per kWh for all Off-Peak kWh during the billing months of June - September
~~$0.040900~~ *0.040092*	per kWh for all On-Peak kWh during the billing months of June - September
~~$0.022270~~ *0.021655*	per kWh for all Off-Peak kWh during the billing months of October - May
~~$0.025648~~ *0.025327*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
~~$6.03~~ *9.71*	~~$10.21~~ *8.43*	~~$16.24~~ *18.14*	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of June - September
~~$5.21~~ *8.39*	~~$9.47~~ *7.82*	~~$14.68~~ *16.21*	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of October - May
NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

Non-Capacity	Capacity	Total	
NA	*$0.031296* ~~$0.027987~~	*$0.031296* ~~$0.027987~~	per kWh of On-Peak kWh during the billing months of June - September
NA	*$0.027863* ~~$0.025248~~	*$0.027863* ~~$0.025248~~	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
~~$5.96~~ *9.60*	~~$10.06~~ *8.31*	~~$16.02~~ *17.91*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
~~$5.15~~ *8.29*	~~$9.33~~ *7.71*	~~$14.48~~ *16.00*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of October - May

(Continued on Sheet No. D-67.30)

See Gray Testimony, Page 3, Lines 13-15; Exhibit A-120 (BAG-1), Item No. 13; Exhibit A-16 (MCG-3), Pages 1-24

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-67.30**

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.20)

Monthly Rate (Contd)

Coincident Peak Demand Provision (CPD) (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 1 (CVL 1) (Cont)

Transmission Charge:

Non-Capacity

~~$0.015940~~ *0.017877*	per kWh of On-Peak kWh during the billing months of June - September
~~$0.014813~~ *0.016585*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity

~~$0.026219~~ *0.025470*	per kWh for all Off-Peak kWh during the billing months of June - September
~~$0.040427~~ *0.039617*	per kWh for all On-Peak kWh during the billing months of June - September
~~$0.022012~~ *0.021398*	per kWh for all Off-Peak kWh during the billing months of October - May
~~$0.025351~~ *0.025027*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
~~$5.96~~ *9.60*	~~$10.06~~ *8.31*	~~$16.02~~ *17.91*	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of June - September
~~$5.15~~ *8.29*	~~$9.33~~ *7.71*	~~$14.48~~ *16.00*	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of October - May
NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event

(Continued on Sheet No. D-67.40)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-71.00**

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued From Sheet No. D-70.00)

Monthly Rate
Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.058806*	*$0.016301*	*$0.075107*	per kWh during the calendar months of June - September
	~~$0.050972~~	~~$0.019509~~	~~$0.070481~~	
Low-Peak - Summer	*$0.079044*	*$0.021794*	*$0.100838*	per kWh during the calendar months of June - September
	~~$0.068312~~	~~$0.026083~~	~~$0.094395~~	
Mid-Peak - Summer	*$0.098015*	*$0.027042*	*$0.125057*	per kWh during the calendar months of June - September
	~~$0.084595~~	~~$0.032364~~	~~$0.116959~~	
High-Peak - Summer	*$0.110852*	*$0.030372*	*$0.141224*	per kWh during the calendar months of June - September
	~~$0.095041~~	~~$0.036350~~	~~$0.131391~~	
Off-Peak - Winter	*$0.054695*	*$0.015070*	*$0.069765*	per kWh during the calendar months of October - May
	~~$0.047473~~	~~$0.018036~~	~~$0.065509~~	
Mid-Peak - Winter	*$0.066136*	*$0.018115*	*$0.084251*	per kWh during the calendar months of October - May
	~~$0.056719~~	~~$0.021680~~	~~$0.078399~~	
High-Peak - Winter	*$0.073418*	*$0.019566*	*$0.092984*	per kWh during the calendar months of October - May
	~~$0.061207~~	~~$0.023417~~	~~$0.084624~~	

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.058138*	*$0.016066*	*$0.074204*	per kWh during the calendar months of June - September
	~~$0.050367~~	~~$0.019204~~	~~$0.069571~~	
Low-Peak - Summer	*$0.078146*	*$0.021480*	*$0.099626*	per kWh during the calendar months of June - September
	~~$0.067502~~	~~$0.025675~~	~~$0.093177~~	
Mid-Peak - Summer	*$0.096901*	*$0.026653*	*$0.123554*	per kWh during the calendar months of June - September
	~~$0.083591~~	~~$0.031859~~	~~$0.115450~~	
High-Peak - Summer	*$0.109594*	*$0.029936*	*$0.139530*	per kWh during the calendar months of June - September
	~~$0.093913~~	~~$0.035782~~	~~$0.129695~~	
Off-Peak - Winter	*$0.054074*	*$0.014854*	*$0.068928*	per kWh during the calendar months of October - May
	~~$0.046910~~	~~$0.017754~~	~~$0.064664~~	
Mid-Peak - Winter	*$0.065386*	*$0.017855*	*$0.083241*	per kWh during the calendar months of October - May
	~~$0.056046~~	~~$0.021342~~	~~$0.077388~~	
High-Peak - Winter	*$0.072587*	*$0.019285*	*$0.091872*	per kWh during the calendar months of October - May
	~~$0.060480~~	~~$0.023051~~	~~$0.083531~~	

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.057404*	*$0.015838*	*$0.073242*	per kWh during the calendar months of June - September
	~~$0.049737~~	~~$0.018927~~	~~$0.068664~~	
Low-Peak - Summer	*$0.077160*	*$0.021175*	*$0.098335*	per kWh during the calendar months of June - September
	~~$0.066658~~	~~$0.025306~~	~~$0.091964~~	
Mid-Peak - Summer	*$0.095678*	*$0.026275*	*$0.121953*	per kWh during the calendar months of June - September
	~~$0.082545~~	~~$0.031400~~	~~$0.113945~~	
High-Peak - Summer	*$0.108212*	*$0.029511*	*$0.137723*	per kWh during the calendar months of June - September
	~~$0.092739~~	~~$0.035267~~	~~$0.128006~~	
Off-Peak - Winter	*$0.053391*	*$0.014643*	*$0.068034*	per kWh during the calendar months of October - May
	~~$0.046324~~	~~$0.017499~~	~~$0.063823~~	
Mid-Peak - Winter	*$0.064561*	*$0.017601*	*$0.082162*	per kWh during the calendar months of October - May
	~~$0.055345~~	~~$0.021035~~	~~$0.076380~~	
High-Peak - Winter	*$0.071673*	*$0.019011*	*$0.090684*	per kWh during the calendar months of October - May
	~~$0.059724~~	~~$0.022720~~	~~$0.082444~~	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	~~$6.68~~ *8.12*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	~~$3.61~~ *4.45*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	~~$2.37~~ *3.28*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above or below .875, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-72.00)

See Gray Testimony, Page 3, Lines 13-15; Exhibit A-120 (BAG-1), Item No. 13; Exhibit A-16 (MCG-3), Pages 1-24

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-72.00**

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued From Sheet No. D-71.00)

Monthly Rate (Contd)

Adjustment for Power Factor (Contd)

(a) If the average Power Factor during the billing period is higher than .875, a $1.14 per Kilovar credit will be applied to the amount which the average lagging Kilovar demand during the billing period is below that for an average Power Factor of .875. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .875, a per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of .875 in accordance with the following table:

Power Factor	Penalty
0.700 to 0.874	$1.14 per Kilovar
Below 0.700	$1.14 per Kilovar first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A $5.25 per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of 0.875, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the $5.25 per Kilovar penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $~~(1.93)~~ *(2.16)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(1.82)~~ *(2.51)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, “school” shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. “College” or “University” shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Educational Institution Credit: $~~(0.000205)~~ *(0.000226)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-72.10)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-75.00**

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued From Sheet No. D-74.50)

Monthly Rate
Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.057201* ~~$0.050699~~	*$0.012331* ~~$0.014831~~	*$0.069532* ~~$0.065530~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.078521* ~~$0.068798~~	*$0.016487* ~~$0.019829~~	*$0.095008* ~~$0.088627~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.098030* ~~$0.086207~~	*$0.020457* ~~$0.024605~~	*$0.118487* ~~$0.110812~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.109997* ~~$0.096332~~	*$0.022977* ~~$0.027635~~	*$0.132974* ~~$0.123967~~	per kWh during the calendar months of June - September
Interruptible Credit	$0.000000	*$(0.008502)* ~~$(0.008461)~~	*$(0.008502)* ~~$(0.008461)~~	per kWh during the calendar months of June - September
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June - September
Critical Peak - Summer Economic Event				the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September
Off-Peak - Winter	*$0.053790* ~~$0.047488~~	*$0.011401* ~~$0.013712~~	*$0.065191* ~~$0.061200~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.064754* ~~$0.056655~~	*$0.013704* ~~$0.016483~~	*$0.078458* ~~$0.073138~~	per kWh during the calendar months of October - May
High-Peak – Winter	*$0.071590* ~~$0.060716~~	*$0.014802* ~~$0.017803~~	*$0.086392* ~~$0.078519~~	per kWh during the calendar months of October - May
Interruptible Credit	$0.000000	*$(0.008502)* ~~$(0.008461)~~	*$(0.008502)* ~~$(0.008461)~~	per kWh during the calendar months of October - May
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of October - May
Critical Peak - Winter Economic Event				the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.056558* ~~$0.050106~~	*$0.012154* ~~$0.014600~~	*$0.068712* ~~$0.064706~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.077642* ~~$0.067996~~	*$0.016250* ~~$0.019519~~	*$0.093892* ~~$0.087515~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.096932* ~~$0.085204~~	*$0.020163* ~~$0.024220~~	*$0.117095* ~~$0.109424~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.108766* ~~$0.095210~~	*$0.022646* ~~$0.027203~~	*$0.131412* ~~$0.122413~~	per kWh during the calendar months of June - September
Interruptible Credit	$0.000000	*$(0.008502)* ~~$(0.008461)~~	*$(0.008502)* ~~$(0.008461)~~	per kWh during the calendar months of June - September
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June - September
Critical Peak - Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September

Off-Peak - Winter	*$0.053187* ~~$0.046934~~	*$0.011237* ~~$0.013498~~	*$0.064424* ~~$0.060432~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.064027* ~~$0.055993~~	*$0.013507* ~~$0.016225~~	*$0.077534* ~~$0.072218~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.070789* ~~$0.060006~~	*$0.014589* ~~$0.017525~~	*$0.085378* ~~$0.077531~~	per kWh during the calendar months of October - May
Interruptible Credit	$0.000000	*$(0.008502)* ~~$(0.008461)~~	*$(0.008502)* ~~$(0.008461)~~	per kWh during the calendar months of October - May
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of October - May
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

(Continued on Sheet No. D-76.00)

See Gray Testimony, Page 3, Lines 13-15; Exhibit A-120 (BAG-1), Item No. 13; Exhibit A-16 (MCG-3), Pages 1-24

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued From Sheet No. D-75.00)

Monthly Rate (Contd)

Power Supply Charges:

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.055848* ~~$0.049484~~	*$0.011981* ~~$0.014390~~	*$0.067829* ~~$0.063874~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.076668* ~~$0.067153~~	*$0.016019* ~~$0.019239~~	*$0.092687* ~~$0.086392~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.095717* ~~$0.084148~~	*$0.019877* ~~$0.023872~~	*$0.115594* ~~$0.108020~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.107402* ~~$0.094029~~	*$0.022325* ~~$0.026812~~	*$0.129727* ~~$0.120841~~	per kWh during the calendar months of June - September
Interruptible Credit	$0.000000	*$(0.008502)* ~~$(0.008461)~~	*$(0.008502* ~~$(0.008461)~~	per kWh during the calendar months of June - September
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June - September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September
Off-Peak - Winter	*$0.052520* ~~$0.046352~~	*$0.011077* ~~$0.013303~~	*$0.063597* ~~$0.059655~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.063224* ~~$0.055298~~	*$0.013315* ~~$0.015992~~	*$0.076539* ~~$0.071290~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.069902* ~~$0.059261~~	*$0.014382* ~~$0.017272~~	*$0.084284* ~~$0.076533~~	per kWh during the calendar months of October - May
Interruptible Credit	$0.000000	*$(0.008502)* ~~$(0.008461)~~	*$(0.008502* ~~$(0.008461)~~	per kWh during the calendar months of October - May
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of October - May
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL 3)		
Capacity Charge:	$~~6.68~~ *8.12*	per kW of Maximum Demand
Charge for Customer Voltage Level 2 (CVL 2)		
Capacity Charge:	$~~3.61~~ *4.45*	per kW of Maximum Demand
Charge for Customer Voltage Level 1 (CVL 1)		
Capacity Charge:	$~~2.37~~ *3.28*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-77.00)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued From Sheet No. D-76.00)

Monthly Rate (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above or below .875, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is higher than .875, a $1.14 per Kilovar credit will be applied to the amount which the lagging Kilovar demand during the billing period is below that for an average Power Factor of .875. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .875, a per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of .875 in accordance with the following table:

Power Factor	**Penalty**
0.700 to 0.874	$1.14 per Kilovar
Below 0.700	$1.14 per Kilovar first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A $5.25 per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of 0.875, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the $5.25 per Kilovar penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Interruptible Credit

Due to the nature of this rate schedule, all customers on this rate schedule shall receive an Interruptible Credit per kWh for all consumption for each calendar month.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $~~(1.93)~~ *(2.16)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(1.82)~~ *(2.51)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-78.00)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.10)

Nature of Service

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Where voltage is supplied at a nominal voltage of 25,000 volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 volts and where the meter is located on the Company side of the substation transformer, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, from the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered production capacity, transmission capacity and energy to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission as reflected in the Monthly Rate.

Monthly Rate

System Contribution Charge:	$0.000284	per kWh for all kWh

Power Supply Charges:

Production Charge:

Customer Voltage Level 1	$~~11.27~~ *11.82*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$~~11.43~~ *11.99*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$~~11.61~~ *12.16*	per kW of On-Peak Billing Demand for all calendar months

Effective for contracts dated on and after June 7, 2024, the monthly Production Charge is the Cost of New Entry for MISO's Local Resource Zone 7 ("CONE"), as of the time of contract execution. The monthly Production Charge is fixed for the contract term at the rate in effect at the time of contract execution, unless the customer fails to meet the minimum On-Peak Billing Demand required by the Company. Effective for contracts dated on or before June 7, 2024, customers shall pay the monthly Production Charge which was in effect at the time of contract execution.

Transmission Charge:

Customer Voltage Level 1	$1.59	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$1.62	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$1.64	per kW of On-Peak Billing Demand for all calendar months

The monthly Transmission Charge is based on the incremental transmission charges applicable with the load served under this tariff and shall be adjusted and reconciled on an annual basis in the Company's PSCR proceedings.

Energy Charge:

For all energy supplied by the Company, the customer shall be responsible for either the MISO Real-Time or Day Ahead Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh). Customers also enrolled in the Voluntary Large Customer Renewable Program LC-REP (LC-REP) may choose, at the Company's discretion, to have the billing of energy under this Rate Schedule match with the crediting methodology of energy under the LC-REP Program for administrative purposes.

Line losses applied to Energy Charge	
Customer Voltage Level 1	~~3.08~~ *3.19*%
Customer Voltage Level 2	~~4.25~~ *4.63*%
Customer Voltage Level 3	~~5.27~~ *6.11*%

(Continued on Sheet No. D-78.30)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-78.30**

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.20)

Monthly Rate (Contd)

Delivery Charges:

Distribution Charges:

Customer Voltage Level 1:	$2.37	per kW of Maximum Demand
Customer Voltage Level 2:	$3.61	per kW of Maximum Demand
Customer Voltage Level 3:	$6.68	per kW of Maximum Demand

The Distribution Charges for the Large Economic Development Rate are equivalent to the Distribution Charges for Large General Service Primary Demand Rate GPD. The monthly charge per kW of Maximum Demand per calendar month may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities required to serve the customer and a facilities allowance specified in the contract for electric service.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $~~(1.93)~~ *(2.16)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $~~(1.82)~~ *(2.51)* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above or below .875, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is higher than .875, a $1.14 per Kilovar credit will be applied to the amount which the average lagging Kilovar demand during the billing period is below that for an average Power Factor of .875. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .875, a per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of .875 in accordance with the following table:

Power Factor	***Penalty***
0.700 to 0.874	*$1.14 per Kilovar*
Below 0.700	*$1.14 per Kilovar first 2 months*

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A $5.25 per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of 0.875, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the $5.25 per Kilovar penalty applies again.

(Continued on Sheet No. D-78.40)

See Connolly Testimony, Page 11, Lines 22-23; Exhibit A-120 (BAG-1), Item No. 16

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.30)

Monthly Rate (Contd)

Interruptible Service Provision

The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Production Capacity Charge specified in the Large Economic Development Rate.

A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule or require testing to demonstrate the customer's ability to meet the contracted Interruptible Service Capacity.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and the Company shall inform the customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

~~**Interruptible Service Provision: (Contd)**~~

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

(Continued on Sheet No. D-78.50)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.40)

Monthly Rate: (Contd)

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months. The contract for service under this rate shall specify the customer's projected Maximum Demand.

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the calendar month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 35,000 kW. Upon mutual agreement between the customer and the Company, up to 60 months from the initial service date for billing purposes may be granted for the customer to meet the 35,000 kW On-Peak Billing Demand required to be eligible for this rate.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.8., Renewable Energy Credit (REC) Programs.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the sum of monthly Capacity Charges and any applicable non-consumption based Surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Form of Contract and Authority to Require a Minimum On-Peak Billing Demand by Date Certain:

Service under this rate shall require a written agreement between the customer and the Company. The Company may require the customer to meet a minimum On-Peak Billing Demand (in addition to the 35,000 kW required to be eligible for this rate) by a date certain, which shall not exceed the customer's projected Maximum Demand specified in the contract. If the customer fails to meet the minimum On-Peak Billing Demand requirement required by its contract for service under this rate, the customer's Production Charge will be reset at the CONE as of the date certain and annually thereafter for the term of the contract, until the customer meets the required minimum On-Peak Billing Demand, after which the Production Charge will be fixed for the remaining term of the contract.

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-81.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts and where the meter is located on the Company side of the substation transformer, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges:

Power Supply Standby Charges:

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500.

Real Power Losses:

Real Power Losses shall be measured based on the transmission loss factor of ~~2.12~~ *2.20*% plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~0.986~~ *0.917*%
Customer Voltage Level 2	~~1.359~~ *1.320*%	~~2.247~~ *2.220*%
Customer Voltage Level 3	~~3.268~~ *3.237*%	~~6.502~~ *7.963*%

Delivery Standby Charges:

System Access Charge: $100.00 per generator installation per month

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge: $~~6.68~~ *8.12* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $~~3.61~~ *4.45* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $~~2.37~~ *3.28* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-83.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-82.00)

Monthly Rate (Contd)

Standby Charges: (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above or below .875, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is higher than .875, a $1.14 per Kilovar credit will be applied to the amount which the average lagging Kilovar demand during the billing period is below that for an average Power Factor of .875. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .875, a per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of .875 in accordance with the following table:

Power Factor	**Penalty**
0.700 to 0.874	$1.14 per Kilovar
Below 0.700	$1.14 per Kilovar first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A $5.25 per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of 0.875, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the $5.25 per Kilovar penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges:

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $~~(1.93)~~ *(2.16)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(1.82)~~ *(2.51)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-83.10)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-83.10**

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-83.00)

Monthly Rate (Contd)

Standby Charges: (Contd)

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges:

Transmission Interconnect Credit: $~~(2.37)~~ *(3.28)* per kW of Maximum Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-84.00)

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage:

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service:

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage:

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge:

Energy Charge:

Non-Capacity	Capacity	Total	
$0.055240		*$0.055240*	per kWh for all kWh
~~$0.045272~~	$0.000000	~~$0.045272~~	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-86.00)

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-85.00)

Monthly Rate (Contd)

Secondary Delivery Charge:

System Access Charge:	$10.00	per customer per month
Distribution Charge:	~~$0.118564~~ *0.135414*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Primary Power Supply Charge:

Energy Charge:

Non-Capacity	Capacity	Total	
$0.027109		*$0.027109*	per kWh for all kWh
~~$0.022217~~	$0.000000	~~$0.022217~~	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Primary Delivery Charge

System Access Charge:	$20.00	per customer per month
Distribution Charge:	~~$0.090355~~ *0.103197*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.8., Renewable Energy Credits (REC) Programs.

(Continued on Sheet No. D-87.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-88.00**

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

This Rate is Not Open to New Business

Availability:

As of XX/XX/2027, this Rate Schedule is closed to new unmetered lighting installations. All new unmetered lighting installations shall take service under the General Unmetered Light Emitting Diode Lighting Rate (GU-LED). Any conversion, replacement, or upgrade of existing luminaires will be to LED, and service will be transitioned to the GU-LED rate. Upon transition, all terms, conditions, and charges of the GU-LED rate schedule shall apply.

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for (i) unmetered lighting service where the Company has existing distribution lines available for supplying energy for such service or (ii) for any Company-owned system consisting of one or more luminaires. This rate is also available to existing farm or Non-Residential customers previously served under General Service Outdoor Lighting Rate L-4, but closed to new business.

~~New installations under this rate require approval by the Company of the proposed design and type of any customer equipment. In the event that the Company does not approve the design, the Company may require the customer to be served under a general service metered rate provision.~~

This rate is not available for resale purposes or for Retail Open Access Service. Only streetlighting types referenced within this rate schedule may receive unmetered service. Other types of streetlighting are excluded from service under this Rate Schedule. *Existing non-LED luminaires installed prior to XX/XX/2027 may remain in service until conversion to LED, or until service is otherwise terminated by either party upon three months' written notice or by mutual agreement.*

Changes in the federal or state law have limited or eliminated the manufacture or importing of supplies needed to maintain some types of existing lighting offered under this Rate Schedule. ~~To the extent that the Company has the necessary materials, the Company will continue to maintain existing mercury vapor lamp installations in accordance with this Electric Rate Schedule~~.

Nature of Service:

Customer-Owned

In systems where the Company has existing distribution lines available for supplying energy for unmetered lighting service, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and own the rest of the equipment comprising the unmetered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. All of the customer's equipment shall be subject to the Company's approval. The Company shall connect the customer's equipment to the Company's lines~~,~~ *and* supply the energy~~.~~ *.* ~~control the burning hours of the lamps, provide normal replacement of luminaire glassware and lamps, and paint metal parts as needed; all other~~ *All* maintenance and replacement of the customer's equipment shall be paid for by the customer.

Company-Owned

In Company-owned systems consisting of one or more luminaires, the Company shall ~~furnish, install and~~ own all equipment comprising the unmetered lighting system. The Company shall supply the energy~~, and renew~~ and maintain the entire equipment *for eligible existing installation, which may remain in service until such time as conversion to LED is performed or the customer elects to terminate service*. In areas where the Company has installed an underground electric distribution system pursuant to the Company's residential underground electric distribution policy as set forth in its Electric Rate Book, the unmetered lighting system shall be served from said underground electric distribution system. In all other areas, the unmetered lighting system shall normally be served from overhead lines or from underground cables installed at customer's request pursuant to special unmetered lighting provisions contained in Monthly Rate clause and Facilities Policy.

Outdoor Lighting

For existing outdoor lighting, luminaires and control equipment shall be ~~furnished,~~ owned~~, installed~~ and maintained by the Company. Luminaires shall be installed on Company-owned or Company-leased poles and must be accessible to the Company's construction and maintenance equipment.

Facilities Policy:

Customer-Owned

At the customer's request, the Company shall install, at its own cost, its distribution facilities under this rate to the extent that the cost of such installation does not exceed the allowance granted under the Company's general service line extension policy. Costs of facilities in excess of the free allowance shall require an advance, nonrefundable, contribution in the amount by which the estimated costs exceed the free allowance.

(Continued on Sheet No. D-89.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-89.00**

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-88.00)

Facilities Policy: (Contd)

Company-Owned

At the customer's request, the Company shall ~~install new luminaires and associated~~ *maintain* facilities *served* under this rate ~~or replace existing luminaires and associated facilities served under this rate with other luminaires and associated facilities for which it has rates available in accordance with the following guidelines:~~ *for any existing non-LED luminaires installed prior to XX/XX/2027, subject to the following provisions:*

~~A.~~ ~~The installation of all new, standard unmetered lights shall require a customer contribution of $230 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond 350 feet shall require a contribution based on the Company's general service line extension policy.~~

~~B.~~ *Customer-Requested Conversion*

At the customer's request, the Company shall convert its existing incandescent/fluorescent luminaires to the nearest *equivalent* ~~standard size high-pressure sodium~~ *LED* luminaire at no cost to the customer. If ~~requirements for installations make it necessary for~~ *conversion is required* ~~the Company to convert luminaires or if the customer requests a conversion of luminaires that the Company can no longer maintain~~ due to federal or state requirements *or the unavailability of required materials*, the Company shall cover the cost of the ~~bulb~~ *LED luminaire* and the customer shall be responsible for all other expenses as a contribution.

For customers with existing high-pressure sodium (HPS) luminaires, the Company shall, upon customer request, convert such luminaires to the nearest equivalent LED luminaire. The customer shall pay the estimated cost of conversion. Where the upgrading results in additional revenues to the Company the customer shall receive a credit calculated in accordance with the Company's general service line extension policy to be applied against the estimated cost of conversion.

Company-Initiated Conversion

For conversions completed with normal Company maintenance such as replacement of bulbs *or luminaires* ~~on a routine schedule~~ or due to failure*, the Company shall, as part of normal maintenance or service, replace the luminaire with a Company-standard LED luminaire at no cost to the customer* ~~then the average cost of that work type shall be deducted from the total work order cost to determine the required customer contribution~~. If other light*ing facilities are* ~~upgrading is~~ also involved, the Company expenditure shall be calculated in accordance with the Company's general service line extension policy. Any costs in excess of this amount shall be borne by the customer.

~~Additional annual revenue is the greater of (1) the difference between the annual revenue from the nearest size high-pressure sodium luminaire and the annual delivery revenue from the upgraded light which would be installed or (2) the difference between the annual delivery revenue from the existing light and the annual delivery revenue from the light which would be installed.~~

~~C.~~ ~~Where upgrading of high-pressure sodium unmetered lights are requested, the customer shall pay the estimated cost of conversion. Where the upgrading results in additional revenues to the Company the customer shall receive a credit calculated in accordance with the Company's general service line extension policy to be applied against the estimated cost of conversion. If the cost of conversion is overestimated, the Company shall, upon completion of construction, refund that portion of the contribution resulting from the overestimate.~~

~~D.~~ ~~Where Company-approved nonstandard poles are requested, the customer contribution shall be the difference in installed cost between standard wood poles and the requested pole. Where Company-approved nonstandard fixtures are requested, a customer contribution shall be required to cover costs in excess of the equivalent Company standard fixture.~~

~~E.~~ ~~For unmetered lighting systems installed underground (exclusive of subdivisions where the developer's contribution provided for underground unmetered lighting), the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction. No contribution shall be required for that footage of unmetered lighting cable which can be satisfactorily installed in underground conduit furnished by the customer for the Company's use and in accordance with the Company's specification.~~

~~F.~~ For system-wide conversions from one light source to another, the customer may be limited to an annual quota as determined by the Company.

~~G.~~ ~~If underground unmetered lighting cable is requested, except that requested in conjunction with the Company's residential underground electric distribution policy, the customer shall contribute to the Company the difference between the Company's estimated installed costs of the underground unmetered lighting cable and the Company's estimated installed costs of standard overhead unmetered lighting conductors.~~

(Continued on Sheet No. D-90.00)

See Schmoekel Testimony, Page 31, Lines 7-8; Exhibit A-120 (BAG-1), Item No. 17

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.00)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after ~~May 1, 2026~~ *XXXXXXX XX, 2027*:

Company-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.28~~ *0.38*	$0.00	$~~0.28~~ *0.38*	$~~10.29~~ *11.04*	$~~10.57~~ *11.42*
25-34	$~~0.43~~ *0.57*	$0.00	$~~0.43~~ *0.57*	$~~11.07~~ *11.92*	$~~11.50~~ *12.49*
35-44	$~~0.57~~ *0.76*	$0.00	$~~0.57~~ *0.76*	$~~11.85~~ *12.81*	$~~12.42~~ *13.57*
45-54	$~~0.72~~ *0.96*	$0.00	$~~0.72~~ *0.96*	$~~12.63~~ *13.69*	$~~13.35~~ *14.65*
55-64	$~~0.86~~ *1.15*	$0.00	$~~0.86~~ *1.15*	$~~13.41~~ *14.58*	$~~14.27~~ *15.73*
65-74	$~~1.01~~ *1.34*	$0.00	$~~1.01~~ *1.34*	$~~14.19~~ *15.46*	$~~15.20~~ *16.80*
75-84	$~~1.15~~ *1.53*	$0.00	$~~1.15~~ *1.53*	$~~14.97~~ *16.35*	$~~16.12~~ *17.88*
85-94	$~~1.29~~ *1.73*	$0.00	$~~1.29~~ *1.73*	$~~15.75~~ *17.23*	$~~17.04~~ *18.96*
95-104	$~~1.44~~ *1.92*	$0.00	$~~1.44~~ *1.92*	$~~16.53~~ *18.12*	$~~17.97~~ *20.04*
105-114	$~~1.58~~ *2.11*	$0.00	$~~1.58~~ *2.11*	$~~17.31~~ *19.00*	$~~18.89~~ *21.11*
115-124	$~~1.73~~ *2.31*	$0.00	$~~1.73~~ *2.31*	$~~18.09~~ *19.89*	$~~19.82~~ *22.20*
125-134	$~~1.87~~ *2.50*	$0.00	$~~1.87~~ *2.50*	$~~18.86~~ *20.77*	$~~20.73~~ *23.27*
135-144	$~~2.02~~ *2.69*	$0.00	$~~2.02~~ *2.69*	$~~19.64~~ *21.66*	$~~21.66~~ *24.35*
145-154	$~~2.16~~ *2.88*	$0.00	$~~2.16~~ *2.88*	$~~20.42~~ *22.54*	$~~22.58~~ *25.42*
155-164	$~~2.31~~ *3.08*	$0.00	$~~2.31~~ *3.08*	$~~21.20~~ *23.43*	$~~23.51~~ *26.51*
165-174	$~~2.45~~ *3.27*	$0.00	$~~2.45~~ *3.27*	$~~21.98~~ *24.31*	$~~24.43~~ *27.58*
175-184	$~~2.60~~ *3.46*	$0.00	$~~2.60~~ *3.46*	$~~22.76~~ *25.19*	$~~25.36~~ *28.65*
185-194	$~~2.74~~ *3.66*	$0.00	$~~2.74~~ *3.66*	$~~23.54~~ *26.08*	$~~26.28~~ *29.74*
195-204	$~~2.89~~ *3.85*	$0.00	$~~2.89~~ *3.85*	$~~24.32~~ *26.96*	$~~27.21~~ *30.81*
205-214	$~~3.03~~ *4.04*	$0.00	$~~3.03~~ *4.04*	$~~25.10~~ *27.85*	$~~28.13~~ *31.89*
215-224	$~~3.17~~ *4.24*	$0.00	$~~3.17~~ *4.24*	$~~25.88~~ *28.73*	$~~29.05~~ *32.97*
225-234	$~~3.32~~ *4.43*	$0.00	$~~3.32~~ *4.43*	$~~26.66~~ *29.62*	$~~29.98~~ *34.05*
235-244	$~~3.46~~ *4.62*	$0.00	$~~3.46~~ *4.62*	$~~27.44~~ *30.50*	$~~30.90~~ *35.12*
245-254	$~~3.61~~ *4.81*	$0.00	$~~3.61~~ *4.81*	$~~28.22~~ *31.39*	$~~31.83~~ *36.20*
255-264	$~~3.75~~ *5.01*	$0.00	$~~3.75~~ *5.01*	$~~29.00~~ *32.27*	$~~32.75~~ *37.28*
265-274	$~~3.90~~ *5.20*	$0.00	$~~3.90~~ *5.20*	$~~29.78~~ *33.16*	$~~33.68~~ *38.36*
275-284	$~~4.04~~ *5.39*	$0.00	$~~4.04~~ *5.39*	$~~30.56~~ *34.04*	$~~34.60~~ *39.43*
285-294	$~~4.19~~ *5.59*	$0.00	$~~4.19~~ *5.59*	$~~31.34~~ *34.93*	$~~35.53~~ *40.52*
295-304	$~~4.33~~ *5.78*	$0.00	$~~4.33~~ *5.78*	$~~32.12~~ *35.81*	$~~36.45~~ *41.59*
305-314	$~~4.48~~ *5.97*	$0.00	$~~4.48~~ *5.97*	$~~32.90~~ *36.70*	$~~37.38~~ *42.67*
315-324	$~~4.62~~ *6.16*	$0.00	$~~4.62~~ *6.16*	$~~33.68~~ *37.58*	$~~38.30~~ *43.74*
325-334	$~~4.77~~ *6.36*	$0.00	$~~4.77~~ *6.36*	$~~34.45~~ *38.47*	$~~39.22~~ *44.83*
335-344	$~~4.91~~ *6.55*	$0.00	$~~4.91~~ *6.55*	$~~35.23~~ *39.35*	$~~40.14~~ *45.90*
345-354	$~~5.05~~ *6.74*	$0.00	$~~5.05~~ *6.74*	$~~36.01~~ *40.24*	$~~41.06~~ *46.98*
355-364	$~~5.20~~ *6.94*	$0.00	$~~5.20~~ *6.94*	$~~36.79~~ *41.12*	$~~41.99~~ *48.06*
365-374	$~~5.34~~ *7.13*	$0.00	$~~5.34~~ *7.13*	$~~37.57~~ *42.01*	$~~42.91~~ *49.14*
375-384	$~~5.49~~ *7.32*	$0.00	$~~5.49~~ *7.32*	$~~38.35~~ *42.89*	$~~43.84~~ *50.21*
385-394	$~~5.63~~ *7.52*	$0.00	$~~5.63~~ *7.52*	$~~39.13~~ *43.78*	$~~44.76~~ *51.30*
395-404	$~~5.78~~ *7.71*	$0.00	$~~5.78~~ *7.71*	$~~39.91~~ *44.66*	$~~45.69~~ *52.37*
405-414	$~~5.92~~ *7.90*	$0.00	$~~5.92~~ *7.90*	$~~40.69~~ *45.55*	$~~46.61~~ *53.45*
415-424	$~~6.07~~ *8.09*	$0.00	$~~6.07~~ *8.09*	$~~41.47~~ *46.43*	$~~47.54~~ *54.52*
425-434	$~~6.21~~ *8.29*	$0.00	$~~6.21~~ *8.29*	$~~42.25~~ *47.32*	$~~48.46~~ *55.61*
435-444	$~~6.36~~ *8.48*	$0.00	$~~6.36~~ *8.48*	$~~43.03~~ *48.20*	$~~49.39~~ *56.68*
445-454	$~~6.50~~ *8.67*	$0.00	$~~6.50~~ *8.67*	$~~43.81~~ *49.09*	$~~50.31~~ *57.76*
455-464	$~~6.65~~ *8.87*	$0.00	$~~6.65~~ *8.87*	$~~44.59~~ *49.97*	$~~51.24~~ *58.84*
465-474	$~~6.79~~ *9.06*	$0.00	$~~6.79~~ *9.06*	$~~45.37~~ *50.86*	$~~52.16~~ *59.92*
475-484	$~~6.94~~ *9.25*	$0.00	$~~6.94~~ *9.25*	$~~46.15~~ *51.74*	$~~53.09~~ *60.99*

(Continued on Sheet No. D-90.20)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after ~~May 1, 2026~~ *XXXXXXX XX, 2027*:

Customer-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.28~~ *0.38*	$0.00	$~~0.28~~ *0.38*	$~~7.29~~ *8.04*	$~~7.57~~ *8.42*
25-34	$~~0.43~~ *0.57*	$0.00	$~~0.43~~ *0.57*	$~~8.07~~ *8.92*	$~~8.50~~ *9.49*
35-44	$~~0.57~~ *0.76*	$0.00	$~~0.57~~ *0.76*	$~~8.85~~ *9.81*	$~~9.42~~ *10.57*
45-54	$~~0.72~~ *0.96*	$0.00	$~~0.72~~ *0.96*	$~~9.63~~ *10.69*	$~~10.35~~ *11.65*
55-64	$~~0.86~~ *1.15*	$0.00	$~~0.86~~ *1.15*	$~~10.41~~ *11.58*	$~~11.27~~ *12.73*
65-74	$~~1.01~~ *1.34*	$0.00	$~~1.01~~ *1.34*	$~~11.19~~ *12.46*	$~~12.20~~ *13.80*
75-84	$~~1.15~~ *1.53*	$0.00	$~~1.15~~ *1.53*	$~~11.97~~ *13.35*	$~~13.12~~ *14.88*
85-94	$~~1.29~~ *1.73*	$0.00	$~~1.29~~ *1.73*	$~~12.75~~ *14.23*	$~~14.04~~ *15.96*
95-104	$~~1.44~~ *1.92*	$0.00	$~~1.44~~ *1.92*	$~~13.53~~ *15.12*	$~~14.97~~ *17.04*
105-114	$~~1.58~~ *2.11*	$0.00	$~~1.58~~ *2.11*	$~~14.31~~ *16.00*	$~~15.89~~ *18.11*
115-124	$~~1.73~~ *2.31*	$0.00	$~~1.73~~ *2.31*	$~~15.09~~ *16.89*	$~~16.82~~ *19.20*
125-134	$~~1.87~~ *2.50*	$0.00	$~~1.87~~ *2.50*	$~~15.86~~ *17.77*	$~~17.73~~ *20.27*
135-144	$~~2.02~~ *2.69*	$0.00	$~~2.02~~ *2.69*	$~~16.64~~ *18.66*	$~~18.66~~ *21.35*
145-154	$~~2.16~~ *2.88*	$0.00	$~~2.16~~ *2.88*	$~~17.42~~ *19.54*	$~~19.58~~ *22.42*
155-164	$~~2.31~~ *3.08*	$0.00	$~~2.31~~ *3.08*	$~~18.20~~ *20.43*	$~~20.51~~ *23.51*
165-174	$~~2.45~~ *3.27*	$0.00	$~~2.45~~ *3.27*	$~~18.98~~ *21.31*	$~~21.43~~ *24.58*
175-184	$~~2.60~~ *3.46*	$0.00	$~~2.60~~ *3.46*	$~~19.76~~ *22.19*	$~~22.36~~ *25.65*
185-194	$~~2.74~~ *3.66*	$0.00	$~~2.74~~ *3.66*	$~~20.54~~ *23.08*	$~~23.28~~ *26.74*
195-204	$~~2.89~~ *3.85*	$0.00	$~~2.89~~ *3.85*	$~~21.32~~ *23.96*	$~~24.21~~ *27.81*
205-214	$~~3.03~~ *4.04*	$0.00	$~~3.03~~ *4.04*	$~~22.10~~ *24.85*	$~~25.13~~ *28.89*
215-224	$~~3.17~~ *4.24*	$0.00	$~~3.17~~ *4.24*	$~~23.88~~ *25.73*	$~~26.05~~ *29.97*
225-234	$~~3.32~~ *4.43*	$0.00	$~~3.32~~ *4.43*	$~~23.66~~ *26.62*	$~~26.98~~ *31.05*
235-244	$~~3.46~~ *4.62*	$0.00	$~~3.46~~ *4.62*	$~~24.44~~ *27.50*	$~~27.90~~ *32.12*
245-254	$~~3.61~~ *4.81*	$0.00	$~~3.61~~ *4.81*	$~~25.22~~ *28.39*	$~~28.83~~ *33.20*
255-264	$~~3.75~~ *5.01*	$0.00	$~~3.75~~ *5.01*	$~~26.00~~ *29.27*	$~~29.75~~ *34.28*
265-274	$~~3.90~~ *5.20*	$0.00	$~~3.90~~ *5.20*	$~~26.78~~ *30.16*	$~~30.68~~ *35.36*
275-284	$~~4.04~~ *5.39*	$0.00	$~~4.04~~ *5.39*	$~~27.56~~ *31.04*	$~~31.60~~ *36.43*
285-294	$~~4.19~~ *5.59*	$0.00	$~~4.19~~ *5.59*	$~~28.34~~ *31.93*	$~~32.53~~ *37.52*
295-304	$~~4.33~~ *5.78*	$0.00	$~~4.33~~ *5.78*	$~~29.12~~ *32.81*	$~~33.45~~ *38.59*
305-314	$~~4.48~~ *5.97*	$0.00	$~~4.48~~ *5.97*	$~~29.90~~ *33.70*	$~~34.38~~ *39.67*
315-324	$~~4.62~~ *6.16*	$0.00	$~~4.62~~ *6.16*	$~~30.68~~ *34.58*	$~~35.30~~ *40.74*
325-334	$~~4.77~~ *6.36*	$0.00	$~~4.77~~ *6.36*	$~~31.45~~ *35.47*	$~~36.22~~ *41.83*
335-344	$~~4.91~~ *6.55*	$0.00	$~~4.91~~ *6.55*	$~~32.23~~ *36.35*	$~~37.14~~ *42.90*
345-354	$~~5.05~~ *6.74*	$0.00	$~~5.05~~ *6.74*	$~~33.01~~ *37.24*	$~~38.06~~ *43.98*
355-364	$~~5.20~~ *6.94*	$0.00	$~~5.20~~ *6.94*	$~~33.79~~ *38.12*	$~~38.99~~ *45.06*
365-374	$~~5.34~~ *7.13*	$0.00	$~~5.34~~ *7.13*	$~~34.57~~ *39.01*	$~~39.91~~ *46.14*
375-384	$~~5.49~~ *7.32*	$0.00	$~~5.49~~ *7.32*	$~~35.35~~ *39.89*	$~~40.84~~ *47.21*
385-394	$~~5.63~~ *7.52*	$0.00	$~~5.63~~ *7.52*	$~~36.13~~ *40.78*	$~~41.76~~ *48.30*
395-404	$~~5.78~~ *7.71*	$0.00	$~~5.78~~ *7.71*	$~~36.91~~ *41.66*	$~~42.69~~ *49.37*
405-414	$~~5.92~~ *7.90*	$0.00	$~~5.92~~ *7.90*	$~~37.69~~ *42.55*	$~~43.61~~ *50.45*
415-424	$~~6.07~~ *8.09*	$0.00	$~~6.07~~ *8.09*	$~~38.47~~ *43.43*	$~~44.54~~ *51.52*
425-434	$~~6.21~~ *8.29*	$0.00	$~~6.21~~ *8.29*	$~~39.25~~ *44.32*	$~~45.46~~ *52.61*
435-444	$~~6.36~~ *8.48*	$0.00	$~~6.36~~ *8.48*	$~~40.03~~ *45.20*	$~~46.39~~ *53.68*
445-454	$~~6.50~~ *8.67*	$0.00	$~~6.50~~ *8.67*	$~~40.81~~ *46.09*	$~~47.31~~ *54.76*
455-464	$~~6.65~~ *8.87*	$0.00	$~~6.65~~ *8.87*	$~~41.59~~ *46.97*	$~~48.24~~ *55.84*
465-474	$~~6.79~~ *9.06*	$0.00	$~~6.79~~ *9.06*	$~~42.37~~ *47.86*	$~~49.16~~ *56.92*
475-484	$~~6.94~~ *9.25*	$0.00	$~~6.94~~ *9.25*	$~~43.15~~ *48.74*	$~~50.09~~ *57.99*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-91.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-94.00**

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-93.00)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine LED lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of LED lighting available under this rate.

E. For customer requested material requiring special order, an additional per luminaire per month charge may apply for procurement and material handling. The Company and the Customer shall mutually agree to the monthly charge prior to procurement and installation of the special order material.

F. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered LED Lighting option.

G. Any charges, deposits or contributions may be required in advance of commencement of construction.

H. At the Company's discretion, any fixture may be converted to LED at no cost to the customer. The replaced fixture will be moved to General Unmetered Light Emitting Diode Lighting Rate GU-LED upon completion of the installation and reconciliation of the community's streetlighting inventory for billing accuracy.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Company-Owned Conversion Credit

A conversion credit may be available to Customers who converted to LED municipal streetlighting.

Customers who converted to LED streetlighting before April 1, 2018 are eligible for the following Conversion Credit per billing month beginning with the January 2021 billing month through the December 2028 billing month:

Fixture Credit per Luminaire: $~~(7.72)~~ *(7.57)* per month

(Continued on Sheet No. D-94.10)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-94.20**

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after ~~May 1, 2026~~ *XXXXXXX XX, 2027*:

Company-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.28~~ *0.38*	$0.00	$~~0.28~~ *0.38*	$~~10.29~~ *11.04*	$~~10.57~~ *11.42*
25-34	$~~0.43~~ *0.57*	$0.00	$~~0.43~~ *0.57*	$~~11.07~~ *11.92*	$~~11.50~~ *12.49*
35-44	$~~0.57~~ *0.76*	$0.00	$~~0.57~~ *0.76*	$~~11.85~~ *12.81*	$~~12.42~~ *13.57*
45-54	$~~0.72~~ *0.96*	$0.00	$~~0.72~~ *0.96*	$~~12.63~~ *13.69*	$~~13.35~~ *14.65*
55-64	$~~0.86~~ *1.15*	$0.00	$~~0.86~~ *1.15*	$~~13.41~~ *14.58*	$~~14.27~~ *15.73*
65-74	$~~1.01~~ *1.34*	$0.00	$~~1.01~~ *1.34*	$~~14.19~~ *15.46*	$~~15.20~~ *16.80*
75-84	$~~1.15~~ *1.53*	$0.00	$~~1.15~~ *1.53*	$~~14.97~~ *16.35*	$~~16.12~~ *17.88*
85-94	$~~1.29~~ *1.73*	$0.00	$~~1.29~~ *1.73*	$~~15.75~~ *17.23*	$~~17.04~~ *18.96*
95-104	$~~1.44~~ *1.92*	$0.00	$~~1.44~~ *1.92*	$~~16.53~~ *18.12*	$~~17.97~~ *20.04*
105-114	$~~1.58~~ *2.11*	$0.00	$~~1.58~~ *2.11*	$~~17.31~~ *19.00*	$~~18.89~~ *21.11*
115-124	$~~1.73~~ *2.31*	$0.00	$~~1.73~~ *2.31*	$~~18.09~~ *19.89*	$~~19.82~~ *22.20*
125-134	$~~1.87~~ *2.50*	$0.00	$~~1.87~~ *2.50*	$~~18.86~~ *20.77*	$~~20.73~~ *23.27*
135-144	$~~2.02~~ *2.69*	$0.00	$~~2.02~~ *2.69*	$~~19.64~~ *21.66*	$~~21.66~~ *24.35*
145-154	$~~2.16~~ *2.88*	$0.00	$~~2.16~~ *2.88*	$~~20.42~~ *22.54*	$~~22.58~~ *25.42*
155-164	$~~2.31~~ *3.08*	$0.00	$~~2.31~~ *3.08*	$~~21.20~~ *23.43*	$~~23.51~~ *26.51*
165-174	$~~2.45~~ *3.27*	$0.00	$~~2.45~~ *3.27*	$~~21.98~~ *24.31*	$~~24.43~~ *27.58*
175-184	$~~2.60~~ *3.46*	$0.00	$~~2.60~~ *3.46*	$~~22.76~~ *25.19*	$~~25.36~~ *28.65*
185-194	$~~2.74~~ *3.66*	$0.00	$~~2.74~~ *3.66*	$~~23.54~~ *26.08*	$~~26.28~~ *29.74*
195-204	$~~2.89~~ *3.85*	$0.00	$~~2.89~~ *3.85*	$~~24.32~~ *26.96*	$~~27.21~~ *30.81*
205-214	$~~3.03~~ *4.04*	$0.00	$~~3.03~~ *4.04*	$~~25.10~~ *27.85*	$~~28.13~~ *31.89*
215-224	$~~3.17~~ *4.24*	$0.00	$~~3.17~~ *4.24*	$~~25.88~~ *28.73*	$~~29.05~~ *32.97*
225-234	$~~3.32~~ *4.43*	$0.00	$~~3.32~~ *4.43*	$~~26.66~~ *29.62*	$~~29.98~~ *34.05*
235-244	$~~3.46~~ *4.62*	$0.00	$~~3.46~~ *4.62*	$~~27.44~~ *30.50*	$~~30.90~~ *35.12*
245-254	$~~3.61~~ *4.81*	$0.00	$~~3.61~~ *4.81*	$~~28.22~~ *31.39*	$~~31.83~~ *36.20*
255-264	$~~3.75~~ *5.01*	$0.00	$~~3.75~~ *5.01*	$~~29.00~~ *32.27*	$~~32.75~~ *37.28*
265-274	$~~3.90~~ *5.20*	$0.00	$~~3.90~~ *5.20*	$~~29.78~~ *33.16*	$~~33.68~~ *38.36*
275-284	$~~4.04~~ *5.39*	$0.00	$~~4.04~~ *5.39*	$~~30.56~~ *34.04*	$~~34.60~~ *39.43*
285-294	$~~4.19~~ *5.59*	$0.00	$~~4.19~~ *5.59*	$~~31.34~~ *34.93*	$~~35.53~~ *40.52*
295-304	$~~4.33~~ *5.78*	$0.00	$~~4.33~~ *5.78*	$~~32.12~~ *35.81*	$~~36.45~~ *41.59*
305-314	$~~4.48~~ *5.97*	$0.00	$~~4.48~~ *5.97*	$~~32.90~~ *36.70*	$~~37.38~~ *42.67*
315-324	$~~4.62~~ *6.16*	$0.00	$~~4.62~~ *6.16*	$~~33.68~~ *37.58*	$~~38.30~~ *43.74*
325-334	$~~4.77~~ *6.36*	$0.00	$~~4.77~~ *6.36*	$~~34.45~~ *38.47*	$~~39.22~~ *44.83*
335-344	$~~4.91~~ *6.55*	$0.00	$~~4.91~~ *6.55*	$~~35.23~~ *39.35*	$~~40.14~~ *45.90*
345-354	$~~5.05~~ *6.74*	$0.00	$~~5.05~~ *6.74*	$~~36.01~~ *40.24*	$~~41.06~~ *46.98*
355-364	$~~5.20~~ *6.94*	$0.00	$~~5.20~~ *6.94*	$~~36.79~~ *41.12*	$~~41.99~~ *48.06*
365-374	$~~5.34~~ *7.13*	$0.00	$~~5.34~~ *7.13*	$~~37.57~~ *42.01*	$~~42.91~~ *49.14*
375-384	$~~5.49~~ *7.32*	$0.00	$~~5.49~~ *7.32*	$~~38.35~~ *42.89*	$~~43.84~~ *50.21*
385-394	$~~5.63~~ *7.52*	$0.00	$~~5.63~~ *7.52*	$~~39.13~~ *43.78*	$~~44.76~~ *51.30*
395-404	$~~5.78~~ *7.71*	$0.00	$~~5.78~~ *7.71*	$~~39.91~~ *44.66*	$~~45.69~~ *52.37*
405-414	$~~5.92~~ *7.90*	$0.00	$~~5.92~~ *7.90*	$~~40.69~~ *45.55*	$~~46.61~~ *53.45*
415-424	$~~6.07~~ *8.09*	$0.00	$~~6.07~~ *8.09*	$~~41.47~~ *46.43*	$~~47.54~~ *54.52*
425-434	$~~6.21~~ *8.29*	$0.00	$~~6.21~~ *8.29*	$~~42.25~~ *47.32*	$~~48.46~~ *55.61*
435-444	$~~6.36~~ *8.48*	$0.00	$~~6.36~~ *8.48*	$~~43.03~~ *48.20*	$~~49.39~~ *56.68*
445-454	$~~6.50~~ *8.67*	$0.00	$~~6.50~~ *8.67*	$~~43.81~~ *49.09*	$~~50.31~~ *57.76*
455-464	$~~6.65~~ *8.87*	$0.00	$~~6.65~~ *8.87*	$~~44.59~~ *49.97*	$~~51.24~~ *58.84*
465-474	$~~6.79~~ *9.06*	$0.00	$~~6.79~~ *9.06*	$~~45.37~~ *50.86*	$~~52.16~~ *59.92*
475-484	$~~6.94~~ *9.25*	$0.00	$~~6.94~~ *9.25*	$~~46.15~~ *51.74*	$~~53.09~~ *60.99*

(Continued on Sheet No. D-94.30)

See Gray Testimony, Page 3, Lines 13-15; Exhibit A-120 (BAG-1), Item No. 13; Exhibit A-16 (MCG-3), Pages 1-24

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-94.30**

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.20)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after ~~May 1, 2026~~ *XXXXXXX XX, 2027*:

Customer-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.28~~ *0.38*	$0.00	$~~0.28~~ *0.38*	$~~7.29~~ *8.04*	$~~7.57~~ *8.42*
25-34	$~~0.43~~ *0.57*	$0.00	$~~0.43~~ *0.57*	$~~8.07~~ *8.92*	$~~8.50~~ *9.49*
35-44	$~~0.57~~ *0.76*	$0.00	$~~0.57~~ *0.76*	$~~8.85~~ *9.81*	$~~9.42~~ *10.57*
45-54	$~~0.72~~ *0.96*	$0.00	$~~0.72~~ *0.96*	$~~9.63~~ *10.69*	$~~10.35~~ *11.65*
55-64	$~~0.86~~ *1.15*	$0.00	$~~0.86~~ *1.15*	$~~10.41~~ *11.58*	$~~11.27~~ *12.73*
65-74	$~~1.01~~ *1.34*	$0.00	$~~1.01~~ *1.34*	$~~11.19~~ *12.46*	$~~12.20~~ *13.80*
75-84	$~~1.15~~ *1.53*	$0.00	$~~1.15~~ *1.53*	$~~11.97~~ *13.35*	$~~13.12~~ *14.88*
85-94	$~~1.29~~ *1.73*	$0.00	$~~1.29~~ *1.73*	$~~12.75~~ *14.23*	$~~14.04~~ *15.96*
95-104	$~~1.44~~ *1.92*	$0.00	$~~1.44~~ *1.92*	$~~13.53~~ *15.12*	$~~14.97~~ *17.04*
105-114	$~~1.58~~ *2.11*	$0.00	$~~1.58~~ *2.11*	$~~14.31~~ *16.00*	$~~15.89~~ *18.11*
115-124	$~~1.73~~ *2.31*	$0.00	$~~1.73~~ *2.31*	$~~15.09~~ *16.89*	$~~16.82~~ *19.20*
125-134	$~~1.87~~ *2.50*	$0.00	$~~1.87~~ *2.50*	$~~15.86~~ *17.77*	$~~17.73~~ *20.27*
135-144	$~~2.02~~ *2.69*	$0.00	$~~2.02~~ *2.69*	$~~16.64~~ *18.66*	$~~18.66~~ *21.35*
145-154	$~~2.16~~ *2.88*	$0.00	$~~2.16~~ *2.88*	$~~17.42~~ *19.54*	$~~19.58~~ *22.42*
155-164	$~~2.31~~ *3.08*	$0.00	$~~2.31~~ *3.08*	$~~18.20~~ *20.43*	$~~20.51~~ *23.51*
165-174	$~~2.45~~ *3.27*	$0.00	$~~2.45~~ *3.27*	$~~18.98~~ *21.31*	$~~21.43~~ *24.58*
175-184	$~~2.60~~ *3.46*	$0.00	$~~2.60~~ *3.46*	$~~19.76~~ *22.19*	$~~22.36~~ *25.65*
185-194	$~~2.74~~ *3.66*	$0.00	$~~2.74~~ *3.66*	$~~20.54~~ *23.08*	$~~23.28~~ *26.74*
195-204	$~~2.89~~ *3.85*	$0.00	$~~2.89~~ *3.85*	$~~21.32~~ *23.96*	$~~24.21~~ *27.81*
205-214	$~~3.03~~ *4.04*	$0.00	$~~3.03~~ *4.04*	$~~22.10~~ *24.85*	$~~25.13~~ *28.89*
215-224	$~~3.17~~ *4.24*	$0.00	$~~3.17~~ *4.24*	$~~23.88~~ *25.73*	$~~26.05~~ *29.97*
225-234	$~~3.32~~ *4.43*	$0.00	$~~3.32~~ *4.43*	$~~23.66~~ *26.62*	$~~26.98~~ *31.05*
235-244	$~~3.46~~ *4.62*	$0.00	$~~3.46~~ *4.62*	$~~24.44~~ *27.50*	$~~27.90~~ *32.12*
245-254	$~~3.61~~ *4.81*	$0.00	$~~3.61~~ *4.81*	$~~25.22~~ *28.39*	$~~28.83~~ *33.20*
255-264	$~~3.75~~ *5.01*	$0.00	$~~3.75~~ *5.01*	$~~26.00~~ *29.27*	$~~29.75~~ *34.28*
265-274	$~~3.90~~ *5.20*	$0.00	$~~3.90~~ *5.20*	$~~26.78~~ *30.16*	$~~30.68~~ *35.36*
275-284	$~~4.04~~ *5.39*	$0.00	$~~4.04~~ *5.39*	$~~27.56~~ *31.04*	$~~31.60~~ *36.43*
285-294	$~~4.19~~ *5.59*	$0.00	$~~4.19~~ *5.59*	$~~28.34~~ *31.93*	$~~32.53~~ *37.52*
295-304	$~~4.33~~ *5.78*	$0.00	$~~4.33~~ *5.78*	$~~29.12~~ *32.81*	$~~33.45~~ *38.59*
305-314	$~~4.48~~ *5.97*	$0.00	$~~4.48~~ *5.97*	$~~29.90~~ *33.70*	$~~34.38~~ *39.67*
315-324	$~~4.62~~ *6.16*	$0.00	$~~4.62~~ *6.16*	$~~30.68~~ *34.58*	$~~35.30~~ *40.74*
325-334	$~~4.77~~ *6.36*	$0.00	$~~4.77~~ *6.36*	$~~31.45~~ *35.47*	$~~36.22~~ *41.83*
335-344	$~~4.91~~ *6.55*	$0.00	$~~4.91~~ *6.55*	$~~32.23~~ *36.35*	$~~37.14~~ *42.90*
345-354	$~~5.05~~ *6.74*	$0.00	$~~5.05~~ *6.74*	$~~33.01~~ *37.24*	$~~38.06~~ *43.98*
355-364	$~~5.20~~ *6.94*	$0.00	$~~5.20~~ *6.94*	$~~33.79~~ *38.12*	$~~38.99~~ *45.06*
365-374	$~~5.34~~ *7.13*	$0.00	$~~5.34~~ *7.13*	$~~34.57~~ *39.01*	$~~39.91~~ *46.14*
375-384	$~~5.49~~ *7.32*	$0.00	$~~5.49~~ *7.32*	$~~35.35~~ *39.89*	$~~40.84~~ *47.21*
385-394	$~~5.63~~ *7.52*	$0.00	$~~5.63~~ *7.52*	$~~36.13~~ *40.78*	$~~41.76~~ *48.30*
395-404	$~~5.78~~ *7.71*	$0.00	$~~5.78~~ *7.71*	$~~36.91~~ *41.66*	$~~42.69~~ *49.37*
405-414	$~~5.92~~ *7.90*	$0.00	$~~5.92~~ *7.90*	$~~37.69~~ *42.55*	$~~43.61~~ *50.45*
415-424	$~~6.07~~ *8.09*	$0.00	$~~6.07~~ *8.09*	$~~38.47~~ *43.43*	$~~44.54~~ *51.52*
425-434	$~~6.21~~ *8.29*	$0.00	$~~6.21~~ *8.29*	$~~39.25~~ *44.32*	$~~45.46~~ *52.61*
435-444	$~~6.36~~ *8.48*	$0.00	$~~6.36~~ *8.48*	$~~40.03~~ *45.20*	$~~46.39~~ *53.68*
445-454	$~~6.50~~ *8.67*	$0.00	$~~6.50~~ *8.67*	$~~40.81~~ *46.09*	$~~47.31~~ *54.76*
455-464	$~~6.65~~ *8.87*	$0.00	$~~6.65~~ *8.87*	$~~41.59~~ *46.97*	$~~48.24~~ *55.84*
465-474	$~~6.79~~ *9.06*	$0.00	$~~6.79~~ *9.06*	$~~42.37~~ *47.86*	$~~49.16~~ *56.92*
475-484	$~~6.94~~ *9.25*	$0.00	$~~6.94~~ *9.25*	$~~43.15~~ *48.74*	$~~50.09~~ *57.99*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-95.00)

GENERAL SERVICE UNMETERED RATE GU

Availability

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate

Power Supply Charges:

Energy Charge:

Non-Capacity	Capacity	Total	
$0.061831	*$0.013614*	*$0.075445*	per kWh for all kWh
~~$0.052791~~	~~$0.015927~~	~~$0.068718~~	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$~~0.034452~~ *0.040553*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-97.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. E-22.00**

RETAIL OPEN ACCESS RESIDENTIAL SECONDARY RATE ROA-R

(Continued From Sheet No. E-21.00)

RETAILER:

Monthly Rate - Retailer

Transmission Service

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses

The Retailer is responsible for replacing Real Power Losses of ~~6.502~~ *7.963*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

ROA CUSTOMER:

Monthly Rate - ROA Customer

ROA System Access Charge, Distribution Charge, General Terms, Minimum Charge and Due Date and Late Payment Charge

The System Access Charge, Distribution Charge, General Terms, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00, the Power Plant Securitization Charges shown on Sheet No. D-7.00 and the Karn 1 and 2 Securitization Charges Shown on Sheet No. D-7.10.

Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service shall pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

Customers taking ROA service on December 17, 2020 are excluded from the Karn 1 and 2 Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 17, 2020 or to customers taking service on December 17, 2020 who discontinue taking ROA service any time after December 17, 2020. Customers who discontinue taking ROA service any time after December 17, 2020 and who return to ROA service shall pay the Karn 1 and 2 Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge

A $5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer's previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule E2.5 D., Return to Company Full Service - Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer

Service under this rate shall not require a ROA Service Contract between the Company and a ROA Customer.

RETAIL OPEN ACCESS SECONDARY RATE ROA-S

(Continued From Sheet No. E-23.00)

Metering Requirements

The ROA Customer with a Maximum Demand of less than 20 kW shall be separately metered by a Wireless Under Glass Meter or an Energy Registering Meter, with or without maximum demand registers, of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company.

The ROA Customer with a Maximum Demand of less than 20 kW may elect to install an Interval Data Meter. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The requesting ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with a Maximum Demand of 20 kW or more shall be separately metered by a Wireless Under Glass Meter or an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

RETAILER:
Monthly Rate - Retailer

Transmission Service

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses

The Retailer is responsible for replacing Real Power Losses of ~~6.502~~ *7.963*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

(Continued on Sheet No. E-25.00)

RETAIL OPEN ACCESS PRIMARY RATE ROA-P

Availability

Subject to any restrictions, this rate is available to any customer receiving service at a Primary Voltage for the delivery of Power from the Point of Receipt to the Point of Delivery and for resale service in accordance with Rule C4.4, Resale.

This rate is not available to a ROA-P Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer. This ROA Customer must take service under Retail Open Access Secondary Rate ROA-S.

This rate is not available for unmetered general service or for any unmetered or metered lighting service.

Service under this rate shall be separately metered. The Retailer shall deliver a flat, fixed amount of power every hour of every day.

Any ROA Customer whose monthly minimum Maximum Demand is less than 1,000 kW must utilize an Aggregator.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company shall not be required to, but may expand its existing facilities to make deliveries under this tariff. The ROA Customer and/or Retailer shall be liable for any and all costs incurred as a result of an expansion of facilities made to make deliveries under this tariff.

Metering Requirements

The load under this tariff shall be separately metered by a Wireless Under Glass Meter or an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA customer shall be required to pay the System Access Charge, as provided for under the ROA customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

RETAILER:
Monthly Rate - Retailer

Transmission Service

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses

The Retailer is responsible for replacing Real Power Losses as shown below on the Company's Distribution System associated with the movement of Power and for compensation for losses.

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~0.986~~ *0.917*%
Customer Voltage Level 2	~~1.359~~ *1.320*%	~~2.247~~ *2.220*%
Customer Voltage Level 3	~~3.268~~ *3.237*%	~~6.502~~ *7.963*%

(Continued on Sheet No. E-27.00)

Rate Case Customer Communications

Consumers Energy
Count on Us®

Rate Case Customer Communications

Communicating potential bill impacts in rate cases filed on or after March 1, 2026
Mich Admin Code, R 460.149 (Rule 49)

Key Requirements

Customer Notification

Within 60 days of filing a general rate case, utilities must provide customers with:

- Notice that a rate change has been requested
- Application available for inspection at utility offices and website
- Explanation of proposed rate changes available upon request

Delivery Method

- Bill insert or same method used for billing
- Utility's website

Commission Findings

- Notices must include both dollar and percentage impacts on average residential and commercial bills
- Information must appear physically (bill insert or on the bill) and digitally (website homepage and app home screen)
- Initial information based on the application; revised after the final order; may be removed 60 days after the rate case concludes
- Utilities must include previews of physical and digital notifications in future filings
- A dedicated landing page should provide detailed rate case information, with all notices linking to it

Website Dedicated Landing Page

Dedicated Landing Page for Rate Case Requests on the Company's website

Residential

2026 U-22070 Rate Case Request

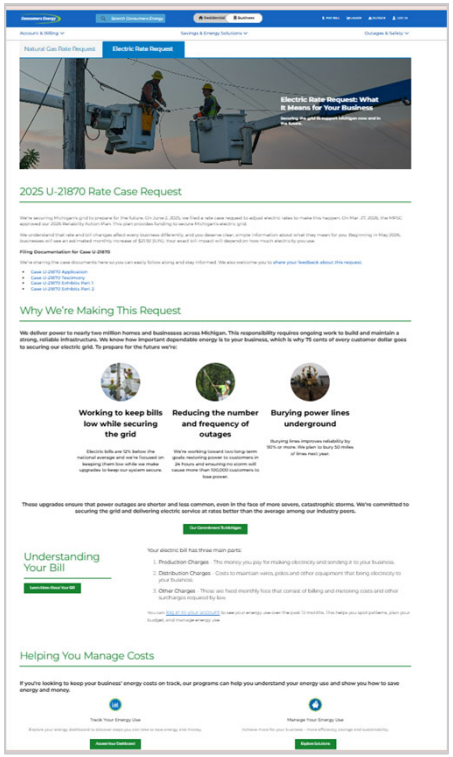
We're securing Michigan's electric grid to prepare for the future. On Jun. 2, 2026, we filed a rate case request with the MPSC to adjust electric rates to make this happen.

We understand that rate and bill changes affect everyone differently, and you deserve clear, simple information about what they mean for you. If the MPSC approves our rate request, the average home with a monthly electric bill of about $132 would see an estimated monthly increase of $13 (9%) starting in May 2027. But your exact bill impact will depend on how much electric you use.

No Immediate Impact
It's important to note there are no immediate changes to customer bills. The MPSC is reviewing this filing and has until Apr. 2027 to approve all or some of the request. When the process is complete, we'll let customers know about any changes to their bill and when they will take effect.

Residential Rate Case Landing Page ▸

Rate Case Landing Page



Business

2026 U-22070 Rate Case Request

We're securing Michigan's electric grid to prepare for the future. On Jun. 2, 2026, we filed a rate case request with the MPSC to adjust electric rates to make this happen.

We understand that rate and bill changes affect every business differently, and you deserve clear, simple information about what they mean for you. If the MPSC approves our rate request, businesses would see an estimated monthly increase of $39 (8.6%). Your exact bill impact will depend on how much electric you use.

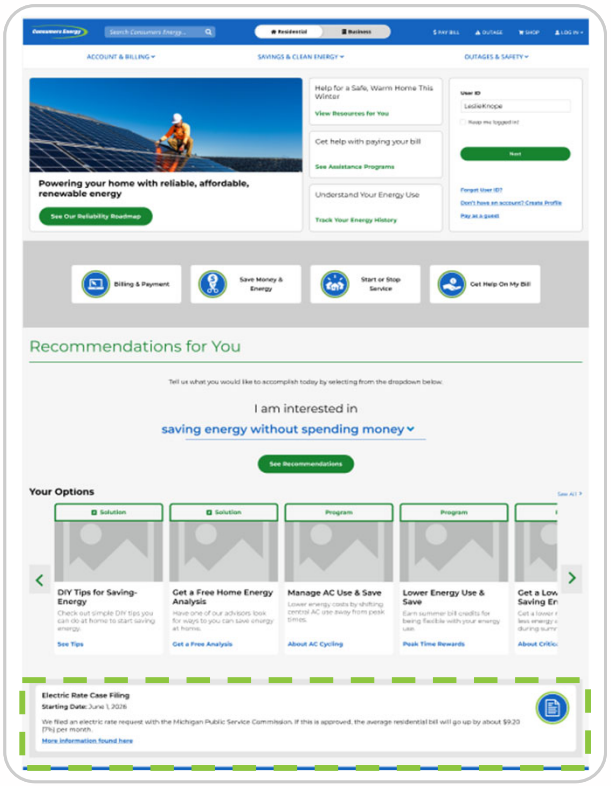
No Immediate Impact
It's important to note there are no immediate changes to customer bills. The MPSC is reviewing this filing and has until Apr. 2027 to approve all or some of the request. When the process is complete, we'll let customers know about any changes to their bill and when they will take effect.

Business Rate Case Landing Page ▸

Website Homepage & Mobile App Home Screen

Rate case notifications displayed on the Company's website homepage and mobile app home screen

Website



What Customers See

Website

Electric Rate Case Application Information

Bill changes affect everyone differently, and you deserve clear, honest information when changes happen. With aging infrastructure and changing weather patterns, work is needed to secure Michigan's grid – and that work requires costs. On June 2, 2026, we asked the Michigan Public Service Commission to approve new electric rates. If approved, the average home will see an estimated monthly increase of $13 (9%) and businesses will see an estimated monthly increase of $39 (8.6%) starting May 2027.

Get more detailed information ▶

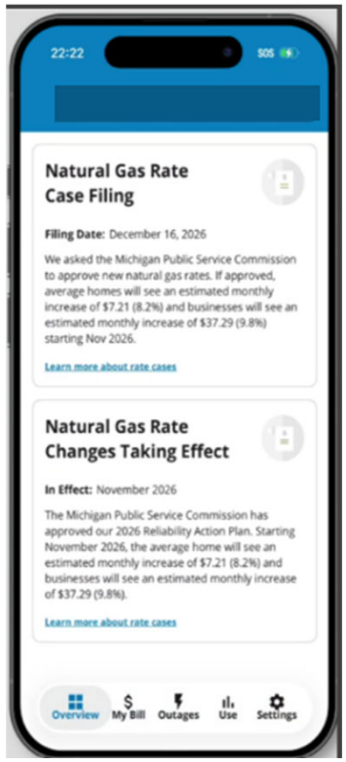
Mobile App

Electric Rate Case Filing

On June 2, 2026, we asked the Michigan Public Service Commission to approve new electric rates. If approved, the average home will see an estimated monthly increase of $13 (9%) and businesses will see an estimated monthly increase of $39 (8.6%) starting May 2027.

Learn more about rate cases

Mobile App



Bill Messages

Rate case notification message included on customer bills within 60 days of filing

Customer Bill



What Customers See

What Customers Will See on Their Bill

- Rate case message below the energy use graph
- Dollar and percentage impact for their rate class
- Effective month/year of new rates

Bill Message Close-Up

Rate Case Application Information

Bill changes affect everyone differently, and you deserve clear, honest information when changes happen. The updates below will help us continue securing Michigan's grid and plan ahead to reliably meet our state's needs today and for years to come.

On Jun. 2, 2026, we asked the Michigan Public Service Commission (MPSC) to approve new electric rates. If approved, the average home with a monthly electric bill of $132 would see an estimated monthly increase of $13 (9%) starting in May 2027.

For detailed information visit: ConsumersEnergy.com/RateRequests

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

ANGEL L. GREEN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2025 and 2026 EICP Operational Goals

Case No.: U-22070
Exhibit No.: A-121 (ALG-1)
Page: 1 of 1
Witness: ALGreen
Date: June 2026

Employee Incentive Compensation Plan - Metric Explanation and Measurement or Calculation Method

Line		Metric	Explanation	Measurement or Calculation Method
1	Employee Safety	**Recordable Incident Rate**	Recordable Incident Rate is benchmarked through EEI (Edison Electric Institute) and is the number of recordable injuries multiplied by 200,000 (industry standard) divided by the total hours worked	# of recordable injuries * 200,000 / total hours worked
2		**High Risk Injuries (2025)**	Number of injuries (Recordable and Non-Recordable) that are classified against the EEI Safety Classification Learning Model as High Risk which includes: High-Energy Serious Injury or Fatality (HSIF) & Potential Serious Injury or Fatality (PSIF)	# of injuries classified as HSIF & PSIF
3		**Serious Injury Incidence Rate (2026)**	Serious Incident Injury Rate is benchmarked through EEI and is the number of injuries or illnesses classified as HSIF or Low Energy Serious Injury or Fatality (LSIF) multiplied by 200,000 (industry standard) divided by the total number of hours worked	# of HSIF and/or LSIF injuries * 200,000 / total hours worked
4	Culture Index	**Employee Engagement Index**	The Employee Engagement index is an average favorability score derived from the taking the total favorable responses received for the 4 questions within the Employee Engagement Category from each of the Company's employee engagement surveys administered by Korn Ferry and they use Qualtrics as the survey platform (https://www.qualtrics.com/) and dividing by the total number of responses received. The Company's Engagement, Empowerment and Diversity, Equity and Inclusion indexes are how we measure our culture values in action. The indexes focus on things like ensuring we have simple processes, fix problems, keep our workforce engaged by measuring the combination of emotional commitment (are you proud to work here?) and rational commitment (do you plan to stay?) and embed diversity, equity and inclusion into everything we do.	This index is an average of the scores of 4 questions: 1. I would recommend my Company as a good place to work. 2. I understand how my job contributes to the Company's strategic priorities and goals. 3. I feel proud to work for the Company. 4. I feel motivated to do more than is required of me.
5		**Employee Empowerment Index**	The Employee Empowerment index is an average favorability score derived from the taking the total favorable responses received for the 4 questions within the Employee Empowerment Category from each of the Company's employee engagement surveys administered by Korn Ferry and they use Qualtrics as the survey platform (https://www.qualtrics.com/) and dividing by the total number of responses received. The Company's Engagement, Empowerment and Diversity, Equity and Inclusion indexes are how we measure our culture values in action. The indexes focus on things like ensuring we have simple processes, fix problems, keep our workforce engaged by measuring the combination of emotional commitment (are you proud to work here?) and rational commitment (do you plan to stay?) and embed diversity, equity and inclusion into everything we do.	This index is an average of the scores of 4 questions: 1. My job makes good use of my skills and abilities. 2. I feel encouraged to come up with new and better ways of doing things. 3. I have enough autonomy to do my job well. 4. There are no significant barriers at work to doing my job well.
6		**Diversity, Equity & Inclusion Index**	The Diversity, Equity and Inclusion index is an average favorability score derived from the taking the total favorable responses received for the 4 questions within the Diversity, Equity and Inclusion Category from each of the Company's employee engagement surveys administered by Korn Ferry and they use Qualtrics as the survey platform (https://www.qualtrics.com/) and dividing by the total number of responses received. The Company's Engagement, Empowerment and Diversity, Equity and Inclusion indexes are how we measure our culture values in action. The indexes focus on things like ensuring we have simple processes, fix problems, keep our workforce engaged by measuring the combination of emotional commitment (are you proud to work here?) and rational commitment (do you plan to stay?) and embed diversity, equity and inclusion into everything we do.	This index is an average of the scores of 4 questions. 1. My Company values and promotes employee diversity. 2. I am treated with respect as an individual. 3. In my work environment, everyone is treated fairly regardless of personal background or characteristics. 4. I feel like I belong at my Company.
7		**Customer Experience Index**	Customer Experience Index is a survey benchmarked by Forrester (https://go.forrester.com/analytics/) and is a measure of customer service based on 3 questions – Did we meet your needs? Was it easy to do business with us? Was the experience enjoyable.	The metric is calculated by asking those 3 questions of customers on a scale of 1 to 5 with 4s and 5s being positive responses, 1s and 2s being negative responses, and 3s being a neutral response. To calculate the score, the number of negative responses is subtracted by the number of positive responses, which is then divided by the total number of customers responding. The results of the three questions are averaged together to calculate the Customer Experience Index score.
8		**Electric Reliability**	Electric Reliability/SAIDI (System Average Interruption Duration Index) is a utility-industry benchmark; SAIDI indicates the total duration of interruption for the average customer during a predefined period of time, typically one calendar year.	Use of IEEE (Institute of Electrical and Electronics Engineers) standard to exclude outlier events/MEDs (Major Event Days); total customer-minutes of interruption divided by total customers served (i.e. customers on the system).
9		**Methane Emissions Reduction**	Reduce fugitive methane emissions associated with natural gas system. Reductions are obtained as a result of replacing and/or retiring older, aging infrastructure from natural gas distribution.	Summation of reduction in methane emissions associated with Vintage Service Replacements (VSR), Enhanced Infrastructure Replacement Program (EIRP), Other Non-Vintage Replacements (Mains & Services), Well Plug & Abandonment (P&A) and capital replacements from the Leak Backlog. See sub-categories below for more details. Note: Compression Venting was included in previous years; however, is no longer included beginning in 2025. **Vintage Service Replacements** - The methane emission reductions are calculated using emission factors (EFs) for the type of service replaced (copper and Bare steel). The EFs and formulas used are consistent with those defined in EPA's Greenhouse Gas Reporting Rule. **EIRP** - The methane emission reductions are calculated using EFs for the type of main or service replaced. EFs for mains are based on miles replaced while services, as with VSRs above, are based on the number of services. The EFs and formulas used are consistent with those defined in EPA's Greenhouse Gas Reporting Rule. **Other Mains & Services** - same calculations as VSR and EIRP. **Well Plug & Abandon** - The methane emission reductions are calculated using emission factors (EFs) for the type of component retired. The EFs and formulas used are consistent with those defined in EPA's Greenhouse Gas Reporting Rule. **Gas Leak Backlog** - same calculation as VSR.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Customer Benefits: Employee Safety

Case No.: U-22070
Exhibit No.: A-122 (ALG-2)
Page: 1 of 1
Witness: ALGreen
Date: June 2026

CE Employee Safety

411.15 Average of daily run rate of Non-Exempt & Union from P&C

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	LOST TIME			**Lost Days**	**Lost Days**	**Lost Days**			
	Year	**# Safety Incidents**	**# Lost Days**	**Per Incident**	**Cost Per Year**	**Per Incident**	**Medical Expense, Workers Comp, Other Exposure (Annual actual paid Workers**	**Per Incident**	
1	2022	107	2993	28.0	$ 1,230,572	$ 11,501	$ 2,752,881	$ 25,728	
2	2023	125	2598	20.8	$ 1,068,168	$ 8,545	$ 1,980,835	$ 15,847	
3	2024	139	4062	29.2	$ 1,670,091	$ 12,015	$ 3,369,397	$ 24,240	
4	2025	196	5145	26.3	$ 2,115,367	$ 10,793	$ 4,500,444	$ 22,961	
5	**Average**	141.75	3699.5	26.1	$ 1,521,049	$ 10,731	$ 3,150,889	$ 22,228	
6	**2026 Target**	104	2714		$ 1,115,973	$ 10,731	$ 2,311,763	$ 22,228	
									Total
7	**Projected Savings**	**38**	**985**		**$ 405,077**		**$ 839,126**		**$ 1,244,202**
8	**Indirect Cost Savings**	**$923,038**	Notes: 1.1 Multiplier per OSHA Pays Software						
9	**GRAND TOTAL**	**$ 2,167,241**							

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2025 Customer Benefits: Culture Index - Reduced Employee Turnover

Case No.: U-22070
Exhibit No.: A-123 (ALG-3)
Page: 1 of 1
Witness: ALGreen
Date: June 2026

Line No.		(a)	(b)	(c)	(d)	(e)
	Annual Employee Turnover					Average
1	Tenure	2022	2023	2024	2025	
2	<1 - 4 years	4.5%	5.5%	5.2%	2.3%	4.4%
3	5+ years	1.6%	1.5%	1.7%	1.0%	1.5%
4	Total Company	2.5%	2.7%	2.6%	1.3%	2.2%
5	Average Turn Over for peer utilities benchmark					7.3%
6	Average Annual Salary <1-4					$ 102,578
7	Total Employees <1-4					1082
8	2% reduction in turnover for employees with tenure of <1-4 years					22
9	Cost avoidance of 1.5 times average annual salary					$ 3,329,682
10	Cost avoidance of 2.0 times average annual salary					$ 4,439,576

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2025 Customer Benefits: Reliability

Case No.: U-22070
Exhibit No.: A-124 (ALG-4)
Page: 1 of 1
Witness: ALGreen
Date: June 2026

SYSTEM AVERAGE INTERRUPTION DURATION INDEX - SAIDI

Estimated Societal Benefits of Customer Reliability

	(1) SAIDI (2)	SAIFI (3)
2021	228	1.05
2022	182	0.96
2023	176	0.96
2024	155	0.88
2025	163	0.87
2021-2025 Annual Improvement	13	0.04

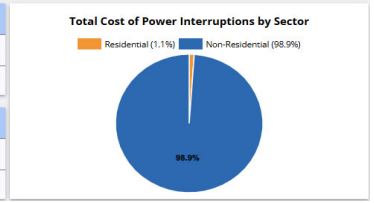
Inputs:		
Model Version: Interrutpion 2.2.0	Baseline	2025
State	Michigan	Michigan
SAIDI	176	163
SAIFI	0.91	0.87
Average Number of Customers (2021-2025)		
Total	1,875,935	1,875,935
Residential	1,577,787	1,577,787
Non-Residential	298,148	298,148
Outputs:		
Total Cost ($)	1,853,223,044	1,743,674,909
Savings ($)		109,548,135
Total Savings ($ millions)		**$110**

Baseline Output from ICE Calculator

Sector	# of Customers	Cost Per Customer (2025 $) Per ... Event	Average kW	Unserved kWh	Minute Interrupted	Annual Cost	Total Cost (2025 $)
Residential	1,577,787	14.14	16.64	5.16	0.07	12.87	20,302,326.23
Non-Residential	298,148	6,755.70	521.06	161.64	34.93	6,147.69	1,832,920,717.75
All Customers	1,875,935	1,085.60	391.16	121.35	5.61	987.89	1,853,223,043.97

Residential Cost/Event Relative To (%): Daily Household Income	Annual Household Income
5.09%	0.01%

Non-Residential Cost/Event Relative To (%): Sector	Daily GDP	Annual GDP
Non-Residential	194.85%	0.49%

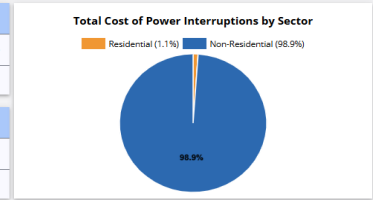


2025 Output from ICE Calculator

Sector	# of Customers	Cost Per Customer (2025 $) Per ... Event	Average kW	Unserved kWh	Minute Interrupted	Annual Cost	Total Cost (2025 $)
Residential	1,577,787	13.86	16.31	5.22	0.07	12.06	19,022,148.69
Non-Residential	298,148	6,648.91	512.82	164.23	35.49	5,784.55	1,724,652,760.15
All Customers	1,875,935	1,068.39	384.96	123.28	5.70	929.50	1,743,674,908.84

Residential Cost/Event Relative To (%): Daily Household Income	Annual Household Income
4.99%	0.01%

Non-Residential Cost/Event Relative To (%): Sector	Daily GDP	Annual GDP
Non-Residential	191.77%	0.46%



STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

KENDRA K. GROB

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Employee Benefits O&M Expenses
For the Years 2025 and Test Year 12 Months ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-125 (KKG-1)
Page: 1 of 2
Witness: KKGrob
Date: June 2026

Line No.	(a) Description	(b) Actual 12 mos. ended 12/31/2025	(c) Projected 12 mos. Ending 04/30/2028
1	Pension Plans A/B	**($47,918)**	**($61,852)**
2	Defined Company Contribution Plan	**16,512**	**17,582**
3	401 (k) Employees' Savings Plan	**13,321**	**14,700**
4	Active Health Care/Life Insurance/LTD	**32,073**	**36,558**
5	Retiree Health Care and Life Insurance	**(49,261)**	**(52,761)**
6	Other Benefits	**2,822**	**3,052**
7	Pension Volatility Mechanism Deferral	**(3,016)**	**0**
8	OPEB Volatility Mechanism Deferral	**1,609**	**0**
9	Pension Volatility Mechanism Amortization	**(2,220)**	**(3,195)**
10	OPEB Volatility Mechanism Amortization	**1,972**	**665**
11	**Total Expense**	**($34,106)**	**($45,251)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of O&M Expenses to Inflation
For the Years 2025 and Test Year 12 Months ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-125 (KKG-1)
Page: 2 of 2
Witness: KKGrob
Date: June 2026

Line No.	Description	(a) 2025 Actual	(b) Inflation Impacts on Historical Costs Test Year (b) * Compounded Inflation Rate	(c) Other Adjustments	(d) Projected O&M 12 Mos Ending 04/30/2028 (b) + (c) + (d)	(e)*
1	**Pension Plans A/B**	**$ (47,918)**	**$ -**	**($13,934)**	**$ (61,852)**	
2	**Defined Company Contribution Plan**	**16,512**	**-**	**1,070**	**17,582**	
3	**401 (k) Employees' Savings Plan**	**13,321**	**-**	**1,379**	**14,700**	
4	**Active Health Care/Life Insurance/LTD**	**32,073**	**-**	**4,485**	**36,558**	
5	**Retiree Health Care and Life Insurance**	**(49,261)**	**-**	**(3,500)**	**(52,761)**	
6	**Other Benefits**	**2,822**	**176**	**54**	**3,052**	
	Other Benefits non labor	**1,894**	**118**	**36**	**2,048**	
	Other Benefits labor	**928**	**58**	**18**	**1,004**	
7	**Pension Volatility Mechanism Deferral**	**(3,016)**	**-**	**3,016**	**-**	
8	**OPEB Volatility Mechanism Deferral**	**1,609**	**-**	**(1,609)**	**-**	
9	**Pension Volatility Mechanism Amortization**	**(2,220)**	**-**	**(975)**	**(3,195)**	
10	**OPEB Volatility Mechanism Amortization**	**1,972**	**-**	**(1,307)**	**665**	
11	**Total Employee Benefits O&M Expenses**	**$ (34,106)**	**$ 176**	**$ (11,321)**	**$ (45,251)**	
	Nonlabor	**(35,034)**	**118**	**(11,339)**	**(46,255)**	
	Labor	**928**	**58**	**18**	**1,004**	

Notes

* Column (e) Projected O&M see WP-KKG-1

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-22070
Exhibit No.: A-126 (KKG-2)
Page: 1 of 3
Witness: KKGrob
Date: June 2026

CMS Energy

Prepared January 2026

ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

	2025	2026	2027	2028
Contribution by Plan Year				
Utility	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Nonutility	0.0	0.0	0.0	0.0
Total	$ 0.0	$ 0.0	$ 0.0	$ 0.0
At-Risk?	No	No	No	No
Benefit Restrictions?	No	No	No	No
Participant Count	2,718	2,641	2,567	2,498
PBGC Liability	$ 1,079.2	$ 1,085.3	$ 1,102.1	$ 1,117.6
Market Value of Assets	$ 1,741.4	$ 1,882.3	$ 1,939.4	$ 1,999.0
PBGC Flat Rate Premium	$ 0.3	$ 0.3	$ 0.3	$ 0.3
PBGC Variable Rate Premium	0.0	0.0	0.0	0.0
Total PBGC Premium	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Projected Benefit Obligation	$ 1,250.7	$ 1,292.5	$ 1,296.5	$ 1,296.7
Market Value of Assets	1,741.4	1,882.3	1,939.4	1,999.0
Funded Status	$ (490.7)	$ (589.8)	$ (642.9)	$ (702.3)
ASC 715 Funded %	139.2%	145.6%	149.6%	154.2%
ASC 715 Accounting Expense				
Utility	$ (39.3)	$ (54.7)	$ (59.3)	$ (67.2)
Nonutility	(1.1)	(1.5)	(1.6)	(1.8)
Total ASC 715 Accounting Expense	$ (40.4)	$ (56.2)	$ (60.9)	$ (69.0)
2020 Settlement Accounting Utility Amortization[1]	5.3	5.3	5.3	5.3
2021 Settlement Accounting Utility Amortization[2]	2.6	2.6	2.6	2.6
2022 Settlement Accounting Utility Amortization[3]	2.7	2.7	2.7	2.7
Total Expense	$ (29.8)	$ (45.6)	$ (50.3)	$ (58.4)
Components of Total Expense				
Service Cost	$ 23.5	$ 22.9	$ 21.0	$ 18.8
Interest Cost	65.7	62.3	62.2	62.0
Expected Return on Assets	(133.3)	(144.3)	(147.0)	(152.7)
Amortization of Outstanding Components	3.7	2.9	2.9	2.9
Total ASC 715 Accounting Expense	$ (40.4)	$ (56.2)	$ (60.9)	$ (69.0)
2020 Settlement Accounting Utility Amortization[1]	5.3	5.3	5.3	5.3
2021 Settlement Accounting Utility Amortization[2]	2.6	2.6	2.6	2.6
2022 Settlement Accounting Utility Amortization[3]	2.7	2.7	2.7	2.7
Total Expense	$ (29.8)	$ (45.6)	$ (50.3)	$ (58.4)
Components of Total Expense -- Utility Only				
Service Cost	$ 22.9	$ 22.3	$ 20.4	$ 18.3
Interest Cost	63.9	60.6	60.5	60.3
Expected Return on Assets	(129.7)	(140.4)	(143.0)	(148.6)
Amortization of Outstanding Components	3.6	2.8	2.8	2.8
Total ASC 715 Accounting Expense	$ (39.3)	$ (54.7)	$ (59.3)	$ (67.2)
Market Related Value of Assets	$ 1,867.1	$ 1,868.8	$ 1,906.0	$ 1,979.0
Assumptions				
Discount Rate	5.73%	5.58%	5.58%	5.58%
Expected Return on Assets	7.30%	7.90%	7.90%	7.90%
Salary Increases	3.70%	3.70%	3.70%	3.70%

[1] The information related to the 2020 Settlement Accounting Utility Amortization was provided directly by CMS and was not calculated or reviewed by Aon. The amortization was set up as a regulatory asset for the utility portion of the 2020 settlement loss of $35.5 million at August 31, 2020. As provided by CMS, the amortizations starts in September 2020 over service life of 8.55 years. Additionally, the settlement attributable to the utility portion on December 31, 2020 is $9.8 million, which is also amortized over service of 8.55 years beginning in January 2021. Nonutility portions of the settlement loss are $0.9 million and $0.3 million for August 31, 2020 and December 31, 2020 respectively.

[2] The information related to the 2021 Settlement Accounting Utility Amortization was provided directly by CMS and was not calculated or reviewed by Aon. The amortization was set up as a regulatory asset for the utility portion of the 2021 settlement loss of $17.6 million at October 31, 2021. As provided by CMS, the amortizations starts in November 2021 over service life of 8.19 years. Additionally, the settlement attributable to the utility portion on December 31, 2021 is $3.3 million, which is also amortized over service of 8.19 years beginning in January 2022. Nonutility portions of the settlement loss are $0.5 million and $0.1 million for October 31, 2021 and December 31, 2021 respectively.

[3] The information related to the 2022 Settlement Accounting Utility Amortization was provided directly by CMS and was not calculated or reviewed by Aon. The amortizations were set up as regulatory assets for the utility portions of the 2022 settlement losses. The settlements attributable to the utility portions are $3.9 million, $3.7 million, $11.5 million, and $2.5 million as of March 31, 2022, June 30, 2022, September 30, 2022, and December 31, 2022 respectively. As provided by CMS, the amortizations are amortized over service life of 8.11 years beginning in April 2022, July 2022, October 2022, and January 2023 respectively. Nonutility portions of the settlement loss are $0.1 million, $0.1 million, $0.3 million, and $0.1 million for March 31, 2022, June 30, 2022, September 30, 2022, and December 31, 2022 respectively.

CMS Energy

Prepared January 2026

ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

	2025	2026	2027	2028
Contribution by Plan Year				
Utility	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Nonutility	0.0	0.0	0.0	0.0
Total	$ 0.0	$ 0.0	$ 0.0	$ 0.0
At-Risk?	No	No	No	No
Benefit Restrictions?	No	No	No	No
Participant Count	7,128	6,959	6,782	6,598
PBGC Liability	$ 853.5	$ 815.8	$ 787.2	$ 756.0
Market Value of Assets	$ 1,222.8	$ 1,294.6	$ 1,308.2	$ 1,324.3
PBGC Flat Rate Premium	$ 0.8	$ 0.8	$ 0.8	$ 0.7
PBGC Variable Rate Premium	0.0	0.0	0.0	0.0
Total PBGC Premium	$ 0.8	$ 0.8	$ 0.8	$ 0.7
Projected Benefit Obligation	$ 843.8	$ 830.4	$ 796.3	$ 761.9
Market Value of Assets	1,222.8	1,294.6	1,308.2	1,324.3
Funded Status	$ (379.0)	$ (464.2)	$ (511.9)	$ (562.4)
ASC 715 Funded %	144.9%	155.9%	164.3%	173.8%
ASC 715 Accounting Expense				
Utility	$ (36.0)	$ (36.4)	$ (32.6)	$ (37.0)
Nonutility	(3.9)	(4.1)	(3.6)	(4.1)
Total	$ (39.9)	$ (40.5)	$ (36.2)	$ (41.1)
Components of Total Expense				
Service Cost	$ 1.7	$ 1.6	$ 1.6	$ 1.6
Interest Cost	42.7	37.6	35.9	34.2
Expected Return on Assets	(95.1)	(93.7)	(91.0)	(92.9)
Amortization of Outstanding Components	10.8	14.0	17.3	16.0
Total Expense	$ (39.9)	$ (40.5)	$ (36.2)	$ (41.1)
Components of Total Expense -- Utility Only				
Service Cost	$ 1.5	$ 1.4	$ 1.4	$ 1.4
Interest Cost	38.5	33.8	32.3	30.8
Expected Return on Assets	(85.7)	(84.3)	(81.9)	(83.6)
Amortization of Outstanding Components	9.7	12.7	15.6	14.4
Total Expense	$ (36.0)	$ (36.4)	$ (32.6)	$ (37.0)
Market Related Value of Assets	$ 1,341.4	$ 1,321.7	$ 1,284.8	$ 1,310.7
Assumptions				
Discount Rate	5.59%	5.28%	5.28%	5.28%
Expected Return on Assets	7.30%	7.30%	7.30%	7.30%
Salary Increases	3.80%	3.75%	3.75%	3.75%

2026-2033 projections reflect the following:

- January 1, 2025 census data.
- PBO discount rate of 5.58% (Plan A) and 5.28% (Plan B) in fiscal 2026+, based on December 31, 2025 yield curve anlaysis.
- Service Cost effective interest rate of 5.67% (Plan A) and 5.80% (Plan B) in fiscal 2026+, based on December 31, 2025 yield curve analysis.
- Interest Cost effective interest rate of 4.98% (Plan A) and 4.75% (Plan B) in fiscal 2026+, based on December 31, 2025 yield curve analysis.
- Expense is allocated to Utility/Non Utility based on PBO using the preliminary allocation percentages for 2026 expense.
- Contributions are allocated to Utility/Non Utility based on the most recent allocation percentages provided by CMS for the December 2020 contributions.
- December 31, 2025 market assets provided by CMS, with expected returns thereafter.
- Expected and actual asset returns of 7.90% (Plan A) and 7.30% (Plan B) in fiscal 2026+.
- The plans will waive Funding Balance when necessary, in order to maintain a Funded Percentage of at least 80%.
- Other provisions, assumptions and methods are the same as those used for the December 31, 2025 ASC 715 disclosures.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-22070
Exhibit No.: A-127 (KKG-3)
Page: 1 of 1
Witness: KKGrob
Date: June 2026

CMS Energy

Prepared January 2026

ASC 715 OPEB Expense Estimates ($ millions)

	2025	2026	2027	2028
Funded Status, January 1				
Accumulated Postretirement Benefit Obligation	$ (831.0)	$ (830.1)	$ (822.9)	$ (813.4)
Plan Assets at Fair Value	1,588.2	1,732.9	1,798.2	1,866.7
Funded Status	$ 757.2	$ 902.8	$ 975.3	$ 1,053.3
ASC 715 Accounting Expense				
Utility	$ (83.9)	$ (101.2)	$ (91.3)	$ (83.9)
Nonutility	(6.9)	(7.9)	(8.0)	(7.9)
Total	$ (90.8)	$ (109.1)	$ (99.3)	$ (91.8)
Components of Total Expense				
Service Cost	$ 8.4	$ 7.7	$ 7.5	$ 7.4
Interest Cost	43.2	39.4	39.0	38.5
Expected Return on Assets	(111.4)	(124.4)	(129.1)	(134.0)
Amortization of Net (Gain) or Loss	2.7	0.0	0.0	0.0
Amortization of Prior Service Cost	(33.7)	(31.8)	(16.7)	(3.7)
Total Expense	$ (90.8)	$ (109.1)	$ (99.3)	$ (91.8)
Components of Total Expense -- Utility Only				
Service Cost	$ 8.2	$ 7.6	$ 7.4	$ 7.2
Interest Cost	41.7	38.0	37.6	37.1
Expected Return on Assets	(103.7)	(115.7)	(120.0)	(124.6)
Amortization of Net (Gain) or Loss	2.8	0.0	0.0	0.0
Amortization of Prior Service Cost	(32.9)	(31.1)	(16.3)	(3.6)
Total Expense	$ (83.9)	$ (101.2)	$ (91.3)	$ (83.9)
Assumptions				
APBO Discount Rate	5.69%	5.50%	5.50%	5.50%
Service Cost Effective Interest Rate	5.85%	5.85%	5.85%	5.85%
Interest Cost Effective Interest Rate	5.39%	4.92%	4.92%	4.92%
Expected Return on Assets	7.15%	7.30%	7.30%	7.30%
Trend Rate—Initial Pre-65	8.50%	8.00%	7.75%	7.25%
Trend Rate—Initial Post-65	10.25%	9.75%	9.25%	8.75%
Trend Rate—Ultimate	4.75%	4.75%	4.75%	4.75%
Trend Rate—Ultimate Year Pre-65	2033	2034	2034	2034
Trend Rate—Ultimate Year Post-65	2033	2034	2034	2034
Expected Contribution	$ 0.0	$ 0.0	$ 0.0	$ 0.0

2026-2032 expense projections reflect the following:

-January 1, 2025 census data.
-APBO discount rate of 5.50% in fiscal 2026+, based on December 31, 2025 yield curve.
-Service Cost effective interest rate of 5.85% in fiscal 2026+, based on December 31, 2025 yield curve.
-Interest Cost effective interest rate of 4.92% in fiscal 2026+, based on December 31, 2025 yield curve.
-December 31, 2025 market assets, provided by CMS
-Other provisions, assumptions and methods are the same as those used for December 31, 2025 ASC 715 disclosures.

EXHIBIT A-128 (KKG-4)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

MICHAEL C. GRONDIN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Schedule F-2.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Total Revenues

Case No.: U-22070
Exhibit No.: A-16 (MCG-1)
Schedule: F-2.0
Page: 1 of 3
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Customers	(c) Sales	(d) Revenue Present	(e) Revenue Proposed	(f) Net Increase / (Decrease) Revenue	(g) Net Increase / (Decrease) Percent
		Mthly	MWh	$000	$000	$000	%
	FULL SERVICE						
	Residential Class						
1	Summer On-peak RSP	1,620,743	12,029,020	$ 2,571,968	$ 2,824,661	$ 252,693	9.8
2	Smart Hours RSH	29,526	201,637	43,348	47,569	4,221	9.7
3	Night Time Savers RPM	17,382	178,119	37,330	41,075	3,745	10.0
4	Non-Transmitting Meters RSM	10,576	104,736	23,194	25,414	2,220	9.6
5	Electric Heating REH	-	-	-	-	-	NA
6	Total Residential Class	1,678,227	12,513,512	$ 2,675,840	$ 2,938,720	$ 262,880	9.8
	Secondary Class						
7	Energy-only GS	207,757	4,088,442	$ 765,021	$ 833,541	$ 68,520	9.0
8	Time-of-Use GSTU	2,267	101,547	18,884	20,591	1,707	9.0
9	Demand GSD	19,819	2,854,081	465,204	502,734	37,530	8.1
10	Total Secondary	229,843	7,044,071	$ 1,249,109	$ 1,356,866	$ 107,757	8.6
	Primary Class						
11	Energy-only GP	1,292	641,900	$ 79,683	$ 82,853	$ 3,169	4.0
12	Demand GPD	698	4,717,731	447,741	475,040	27,299	6.1
13	Time-of-Use GPTU	1,696	4,345,527	479,510	514,626	35,116	7.3
14	Energy Intensive EIP	15	390,752	32,196	34,619	2,423	7.5
15	Total Primary	3,701	10,095,910	$ 1,039,131	$ 1,107,138	$ 68,008	6.5
	Lighting & Unmetered Class						
16	Metered Lighting GML	386	10,465	$ 1,887	$ 2,171	$ 284	15.0
17	Universal Unmetered Lighting UUL	4,700	54,935	33,568	37,438	3,871	11.5
18	Unmetered GU	460	92,721	10,958	12,069	1,111	10.1
19	Total Lighting & Unmetered	5,547	158,121	$ 46,413	$ 51,679	$ 5,265	11.3
	Self-generation Class						
20	Small Self-generation GSG-1	-	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	14	153,194	14,904	15,469	565	3.8
	Voltage Level 1	4	57,084	3,872	3,892	20	0.5
	Voltage Level 2	8	81,548	9,185	9,640	455	5.0
	Voltage Level 3	3	14,562	1,847	1,937	90	4.9
22	Total Self-generation	14	153,194	$ 14,904	$ 15,469	$ 565	3.8
23	Total Full Service	1,917,333	29,964,807	$ 5,025,396	$ 5,469,872	$ 444,476	8.8
	ROA SERVICE						
	Secondary Class						
24	Energy-only GS	78	17,123	$ 1,197	$ 1,465	$ 268	22.4
25	Demand GSD	474	167,933	10,052	11,910	1,858	18.5
26	Total Secondary	552	185,056	$ 11,249	$ 13,375	$ 2,126	18.9
	Primary Class						
27	Energy-only GP	46	70,709	$ 1,750	$ 2,189	$ 439	25.1
28	Demand GPD	375	3,332,675	32,429	40,572	8,143	25.1
29	Total Primary	421	3,403,384	$ 34,179	$ 42,761	$ 8,582	25.1
30	Total ROA Service	973	3,588,440	$ 45,428	$ 56,136	$ 10,708	23.6
31	Total Jurisdictional Service	1,918,306	33,553,247	$ 5,070,824	$ 5,526,008	$ 455,184	9.0
32	Plus: Rounding			-	19	650	
33	Total Jurisdictional Revenues			$ 5,070,824	$ 5,526,027	$ 455,203	9.0
34	Less: PSCR Factor Revenues			421,051	421,051	-	
35	Less: DR Surcharge			50,877	-	(50,877)	
36	Less: IRM Surcharge				20,235	20,235	
37	Total Jurisdictional Base Revenues			$ 4,598,896	$ 5,084,741	$ 485,845	10.6
38	Total Jurisdictional Revenues			5,070,824	5,526,027	455,203	9.0
39	Plus: ERC Deferral Surcharge				25,017	25,017	
40	Total Jurisdictional Revenues Requested			$ 5,070,824	$ 5,551,044	$ 480,220	9.5

Schedule F-2.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Production & Transmission Revenues

Case No.: U-22070
Exhibit No.: A-16 (MCG-1)
Schedule: F-2.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Sales	(c) Revenue Present	(d) Revenue Proposed	(e) Net Increase / (Decrease) Revenue	(f) Net Increase / (Decrease) Percent
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,029,020	$ 1,321,158	$ 1,354,390	$ 33,233	2.5
2	Smart Hours RSH	201,637	21,642	22,598	956	4.4
3	Night Time Savers RPM	178,119	18,897	19,723	826	4.4
4	Non-Transmitting Meters RSM	104,736	11,370	11,669	299	2.6
5	Electric Heating REH	-	-	-	-	NA
6	Total Residential Class	12,513,512	$ 1,373,066	$ 1,408,380	$ 35,314	2.6
	Secondary Class					
7	Energy-only GS	4,088,442	$ 431,381	$ 435,476	$ 4,095	0.9
8	Time-of-Use GSTU	101,547	11,289	11,396	107	0.9
9	Demand GSD	2,854,081	285,488	291,339	5,851	2.0
10	Total Secondary	7,044,071	$ 728,158	$ 738,211	$ 10,053	1.4
	Primary Class					
11	Energy-only GP	641,900	$ 62,764	$ 61,976	$ (788)	(1.3)
12	Demand GPD	4,717,731	396,293	411,005	14,711	3.7
13	Time-of-Use GPTU	4,345,527	392,423	408,476	16,053	4.1
14	Energy Intensive EIP	390,752	29,042	30,409	1,368	4.7
15	Total Primary	10,095,910	$ 880,522	$ 911,865	$ 31,343	3.6
	Lighting & Unmetered Class					
16	Metered Lighting GML	10,465	$ 612	$ 709	$ 97	15.9
17	Universal Unmetered Lighting UUL	54,935	3,053	3,786	734	24.0
18	Unmetered GU	92,721	7,753	8,267	514	6.6
19	Total Lighting & Unmetered	158,121	$ 11,417	$ 12,762	$ 1,345	11.8
	Self-generation Class					
20	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	153,194	12,646	12,646	-	-
	Voltage Level 1	57,084	3,704	3,704	-	-
	Voltage Level 2	81,548	7,503	7,503	-	-
	Voltage Level 3	14,562	1,439	1,439	-	-
22	Total Self-generation	153,194	$ 12,646	$ 12,646	$ -	-
23	Total Full Service	29,964,807	$ 3,005,810	$ 3,083,865	$ 78,055	2.6
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	-	$ -	$ -	$ -	NA
25	Demand GSD	-	-	-	-	NA
26	Total Secondary	-	$ -	$ -	$ -	NA
	Primary Class					
27	Energy-only GP	-	$ -	$ -	$ -	NA
28	Demand GPD	-	-	-	-	NA
29	Total Primary	-	$ -	$ -	$ -	NA
30	Total ROA Service	-	$ -	$ -	$ -	NA
31	Total Jurisdictional Service	29,964,807	$ 3,005,810	$ 3,083,865	$ 78,055	2.6
32	Plus: Rounding		-	21	21	
33	Total Jurisdictional Base Revenues		$ 3,005,810	$ 3,083,886	$ 78,076	2.6
34	Less: PSCR Factor Revenues		421,051	421,051	-	
35	Less: DR Surcharge		-	-	-	
36	Less: IRM Surcharge		-	-	-	
37	Total Jurisdictional Base Revenues		$ 2,584,758	$ 2,662,835	$ 78,076	3.0
38	Total Jurisdictional Revenues		3,005,810	3,083,886	78,076	2.6
39	Plus: ERC Deferral Surcharge		-	-	-	
40	Total Jurisdictional Revenues Requested		$ 3,005,810	$ 3,083,886	$ 78,076	2.6

Schedule F-2.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Delivery Revenues

Case No.: U-22070
Exhibit No.: A-16 (MCG-1)
Schedule: F-2.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Sales	(c) Revenue Present	(d) Revenue Proposed	(e) Net Increase / (Decrease) Revenue	(f) Net Increase / (Decrease) Percent
		MWh	$000	$000	$000	%
	FULL SERVICE					
	Residential Class					
1	Summer On-peak RSP	12,029,020	$ 1,250,811	$ 1,470,271	$ 219,461	17.5
2	Smart Hours RSH	201,637	21,302	24,972	3,670	17.2
3	Night Time Savers RPM	178,119	18,076	21,352	3,276	18.1
4	Non-Transmitting Meters RSM	104,736	11,824	13,745	1,921	16.2
5	Electric Heating REH	-	-	-	-	NA
6	Total Residential Class	12,513,512	$ 1,302,012	$ 1,530,339	$ 228,327	17.5
	Secondary Class					
7	Energy-only GS	4,088,442	$ 333,640	$ 398,065	$ 64,425	19.3
8	Time-of-Use GSTU	101,547	7,595	9,195	1,601	21.1
9	Demand GSD	2,854,081	179,716	211,395	31,679	17.6
10	Total Secondary	7,044,071	$ 520,950	$ 618,655	$ 97,704	18.8
	Primary Class					
11	Energy-only GP	641,900	$ 16,919	$ 20,877	$ 3,958	23.4
12	Demand GPD	4,717,731	51,448	64,036	12,588	24.5
13	Time-of-Use GPTU	4,345,527	87,088	106,151	19,063	21.9
14	Energy Intensive EIP	390,752	3,154	4,210	1,056	33.5
15	Total Primary	10,095,910	$ 158,608	$ 195,273	$ 36,664	23.1
	Lighting & Unmetered Class					
16	Metered Lighting GML	10,465	$ 1,275	$ 1,462	$ 187	14.6
17	Universal Unmetered Lighting UUL	54,935	30,515	33,652	3,137	10.3
18	Unmetered GU	92,721	3,205	3,803	597	18.6
19	Total Lighting & Unmetered	158,121	$ 34,996	$ 38,917	$ 3,921	11.2
	Self-generation Class					
20	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
21	Large Self-generation GSG-2	153,194	2,258	2,824	565	25.0
	Voltage Level 1	57,084	168	188	20	11.8
	Voltage Level 2	81,548	1,682	2,137	455	27.1
	Voltage Level 3	14,562	408	498	90	22.1
22	Total Self-generation	153,194	$ 2,258	$ 2,824	$ 565	25.0
23	Total Full Service	29,964,807	$ 2,018,825	$ 2,386,007	$ 367,182	18.2
	ROA SERVICE					
	Secondary Class					
24	Energy-only GS	17,123	$ 1,197	$ 1,465	$ 268	22.4
25	Demand GSD	167,933	10,052	11,910	1,858	18.5
26	Total Secondary	185,056	$ 11,249	$ 13,375	$ 2,126	18.9
	Primary Class					
27	Energy-only GP	70,709	$ 1,750	$ 2,189	$ 439	25.1
28	Demand GPD	3,332,675	32,429	40,572	8,143	25.1
29	Total Primary	3,403,384	$ 34,179	$ 42,761	$ 8,582	25.1
30	Total ROA Service	3,588,440	$ 45,428	$ 56,136	$ 10,708	23.6
31	Total Jurisdictional Service	33,553,247	$ 2,064,253	$ 2,442,143	$ 377,891	18.3
32	Plus: Rounding		-	(2)	(2)	
33	Total Jurisdictional Base Revenues		$ 2,064,253	$ 2,442,141	$ 377,888	18.3
34	Less: PSCR Factor Revenues		-	-	-	
35	Less: DR Surcharge		-	-	-	
36	Less: IRM Surcharge		-	20,235	20,235	
37	Total Jurisdictional Base Revenues		$ 2,064,253	$ 2,421,907	$ 357,654	17.3
38	Total Jurisdictional Revenues		2,064,253	2,442,141	377,888	18.3
39	Plus: ERC Deferral Surcharge		-	25,017	25,017	
40	Total Jurisdictional Revenues Requested		$ 2,064,253	$ 2,467,158	$ 402,905	19.5

Schedule F-2.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Rate Design Targets
($000)

Case No.: U-22070
Exhibit No.: A-16 (MCG-2)
Schedule: F-2.1
Page: 1 of 1
Witness: MCGrondin
Date: June 2026

Line No.	Description	Jurisdictional	Residential	Secondary Class GS	Secondary Class GSD	Primary Class GP	Primary Class GPD	Primary Class GPTU	Primary Class EIP	Lighting & Unmetered Class GML	Lighting & Unmetered Class UUL	Lighting & Unmetered Class GU	Self Gen. Class GSG-1	Self Gen. Class GSG-2	Source
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Production														
1	Capacity (SRM)	$ 677,033	$ 355,401	$ 98,772	$ 60,200	$ 11,902	$ 68,337	$ 74,173	$ 4,863	$ 6	$ 134	$ 1,243	$ -	$ 2,001	
	Capacity Adjustments [1]														
2	DR Revenue Credits	8,782	4,610	1,281	781	154	886	962	63	0	2	16	-	26	WP-MCG-7
3	Self Generation	-	889	247	151	30	171	186	12	0	0	3	-	(1,689)	Alloc. Line 1
4	Total Adjustments	8,782	5,500	1,528	932	184	1,057	1,148	75	0	2	19	-	(1,663)	
5	Capacity (SRM) Design Target	$ 685,815	$ 360,901	$ 100,300	$ 61,131	$ 12,087	$ 69,394	$ 75,321	$ 4,939	$ 6	$ 136	$ 1,262	$ -	$ 338	
6	Energy [2]	$ 1,282,253	$ 543,329	$ 186,631	$ 127,217	$ 27,102	$ 194,378	$ 184,898	$ 16,572	$ 438	$ 2,371	$ 4,159	$ -	$ (4,843)	
	Energy Adjustments [1]														
7	Self Generation	-	(2,044)	(702)	(479)	(102)	(731)	(696)	(62)	(2)	(9)	(16)	-	4,843	Alloc. Line 6
8	Total Adjustments	-	(2,044)	(702)	(479)	(102)	(731)	(696)	(62)	(2)	(9)	(16)	-	4,843	
9	Energy Design Target	$ 1,282,253	$ 541,285	$ 185,928	$ 126,739	$ 27,000	$ 193,646	$ 184,202	$ 16,510	$ 437	$ 2,363	$ 4,143	$ -	$ -	
10	Total Production	$ 1,968,068	$ 902,186	$ 286,229	$ 187,870	$ 39,087	$ 263,041	$ 259,523	$ 21,449	$ 443	$ 2,498	$ 5,406	$ -	$ 338	
11	**Transmission**														
12	Transmission	703,549	335,866	102,853	64,742	14,042	85,352	89,197	6,903	122	528	1,584	-	2,359	
13	Self Generation	-	1,130	346	218	47	287	300	23	0	2	5	-	(2,359)	Alloc. Line 12
14	Transmission Design Target	$ 703,549	$ 336,996	$ 103,199	$ 64,960	$ 14,089	$ 85,640	$ 89,497	$ 6,926	$ 122	$ 530	$ 1,590	$ -	$ -	
	Delivery														
15	Distribution [3]	$ 2,151,935	$ 1,329,210	$ 360,004	$ 207,980	$ 19,236	$ 103,125	$ 89,919	$ 2,827	$ 1,352	$ 31,575	$ 3,669	$ -	$ 3,038	
16	Customer	269,970	200,586	40,001	10,303	3,186	6,385	7,572	174	84	1,463	97	-	119	
17	Subtotal Delivery	2,421,904	1,529,796	400,005	218,283	22,421	109,510	97,491	3,001	1,436	33,038	3,766	-	3,157	
	Credit Adjustments [4]														
18	Substation Credits	$ (0)	$ 1,988	$ 538	$ 311	$ (6)	$ (1,624)	$ (355)	$ (361)	$ 2	$ 47	$ 5	$ -	$ (546)	WP-MCG-11
19	Life Line Credits	(0)	(14,222)	4,842	2,889	463	2,805	2,731	192	12	288	-	-	-	WP-MCG-8
20	Total Adjustments	(0)	(12,233)	5,380	3,199	457	1,181	2,376	(170)	14	335	5	-	(546)	
21	Total Delivery Design Target	$ 2,421,904	$ 1,517,563	$ 405,385	$ 221,482	$ 22,879	$ 110,690	$ 99,867	$ 2,832	$ 1,450	$ 33,374	$ 3,771	$ -	$ 2,611	
22	Total Rate Design Target	$ 5,093,521	$ 2,756,745	$ 794,812	$ 474,313	$ 76,054	$ 459,371	$ 448,888	$ 31,206	$ 2,016	$ 36,402	$ 10,767	$ -	$ 2,949	
23	IRM Surcharge	$ 20,237	$ 12,776	$ 3,340	$ 1,822	$ 187	$ 1,016	$ 727	$ 32	$ 12	$ 276	$ 31	$ -	$ 16	A-131 (MCG-7)
24	Total Revenue Requirement	$ 5,113,758	$ 2,769,521	$ 798,153	$ 476,135	$ 76,241	$ 460,386	$ 449,615	$ 31,238	$ 2,028	$ 36,678	$ 10,798	$ -	$ 2,965	

Notes
(1) Capacity and energy production costs adjusted to capture elements occurring outside the Cost-of-Service Study.
(2) Includes Non-SRM capacity related costs.
(3) Excludes IRM costs recovered through the IRM surcharge.
(4) Credit adjustments approved in Case No. U-21389

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Summer On-peak (RSP)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 1 of 24
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	853,702	MWh	@	0.060410	$ 51,572	0.070978	$ 60,594	$ 9,022
2	Off-peak kWh	3,681,432	MWh	@	0.041347	152,217	0.047444	174,662	22,445
	Capacity								
3	On-peak kWh	853,702	MWh	@	0.053506	45,678	0.046477	39,678	(6,000)
4	Off-peak kWh	3,681,432	MWh	@	0.036622	134,821	0.031811	117,110	(17,710)
	Winter (Oct. - May)								
5	Non-capacity All kWh	7,493,887	MWh	@	0.033007	247,347	0.038072	285,305	37,958
6	Capacity All kWh	7,493,887	MWh	@	0.029234	219,079	0.025394	190,300	(28,779)
	Provisions								
	Device Cycling								
7	AC Cycling	262,771	Bills	@	(5.00)	(1,314)	(5.00)	(1,314)	-
8	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
9	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
10	Peak Time Rewards	1,924	MWh	@	(0.50)	(962)	(0.50)	(962)	-
	Critical Peak Pricing								
11	Critical-peak Charge	313	MWh	@	1.00	313	1.00	313	-
12	Off-peak Credits	52,133	MWh	@	(0.006373)	(332)	(0.006008)	(313)	19
13	Annual PSCR Factor	12,029,020	MWh	@	0.013710	164,918	0.013710	164,918	-
14	Total Production					$ 1,013,338		$ 1,030,292	$ 16,954
	Transmission								
	Summer (June - Sept.)								
15	On-peak kWh	853,702	MWh	@	0.037988	$ 32,430	0.043399	$ 37,050	$ 4,619
16	Off-peak kWh	3,681,432	MWh	@	0.026001	95,719	0.029704	109,354	13,634
	Winter (Oct. - May)								
17	All kWh	7,493,887	MWh	@	0.020756	155,540	0.023712	177,695	22,155
18	Total Transmission					$ 283,690		$ 324,099	$ 40,409
	Delivery								
19	System Access	19,448,922	Bills	@	8.00	$ 155,591	8.00	$ 155,591	$ -
20	Distribution	12,029,020	MWh	@	0.093333	1,122,702	0.110796	1,332,772	210,070
	Provisions								
21	Senior Citizen (RSC)	4,643,872	Bills	@	(4.00)	(18,575)	(4.00)	(18,575)	-
22	Low Income Credit (LIAC)	74,400	Bills	@	(42.00)	(3,125)	(42.00)	(3,125)	-
23	Income Assistance (RIA)	722,837	Bills	@	(8.00)	(5,783)	(12.00)	(8,674)	(2,891)
24	Total Delivery					$ 1,250,811		$ 1,457,989	$ 207,179
25	Total Full Service					$ 2,547,838		$ 2,812,380	$ 264,542
	ROA SERVICE								
	Delivery								
26	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
27	Distribution	-	MWh	@	0.093333	-	0.110796	-	-
	Provisions								
28	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
29	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
30	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(12.00)	-	-
31	Total Delivery					$ -		$ -	$ -
32	Total Full & ROA Service					$ 2,547,838		$ 2,812,380	$ 264,542

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Smart Hours (RSH)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 2 of 24
Witness: MCGrondin
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	13,477	MWh	@	0.060410	$ 814	0.070978	$ 957	$ 142
2	Off-peak kWh	60,726	MWh	@	0.041347	2,511	0.047444	2,881	370
	Capacity								
3	On-peak kWh	13,477	MWh	@	0.053506	721	0.046477	626	(95)
4	Off-peak kWh	60,726	MWh	@	0.036622	2,224	0.031811	1,932	(292)
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kWh	19,802	MWh	@	0.038335	759	0.046318	917	158
6	Off-peak kWh	107,632	MWh	@	0.031989	3,443	0.036505	3,929	486
	Capacity								
7	On-peak kWh	19,802	MWh	@	0.033954	672	0.029494	584	(88)
8	Off-peak kWh	107,632	MWh	@	0.028333	3,050	0.024611	2,649	(401)
	Provisions								
	Device Cycling								
9	AC Cycling	4,347	Bills	@	(5.00)	(22)	(5.00)	(22)	-
10	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
11	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
12	Peak Time Rewards	61	MWh	@	(0.50)	(31)	(0.50)	(31)	-
	Critical Peak Pricing								
13	Critical-peak Charge	14	MWh	@	1.00	14	1.00	14	-
14	Off-peak Credits	1,742	MWh	@	(0.006373)	(11)	(0.006008)	(10)	1
15	Annual PSCR Factor	201,637	MWh	@	0.013710	2,764	0.013710	2,764	-
16	Total Production					$ 16,909		$ 17,190	$ 282
	Transmission								
	Summer (June - Sept.)								
17	On-peak kWh	13,477	MWh	@	0.037988	$ 512	0.043399	$ 585	$ 73
18	Off-peak kWh	60,726	MWh	@	0.026001	1,579	0.029704	1,804	225
	Winter (Oct. - May)								
19	On-peak kWh	19,802	MWh	@	0.024106	477	0.027540	545	68
20	Off-peak kWh	107,632	MWh	@	0.020116	2,165	0.022981	2,473	308
21	Total Transmission					$ 4,733		$ 5,408	$ 674
	Delivery								
22	System Access	354,311	Bills	@	8.00	$ 2,834	8.00	$ 2,834	$ -
23	Distribution	201,637	MWh	@	0.093333	18,819	0.110796	22,341	3,521
	Provisions								
24	Senior Citizen (RSC)	59,433	Bills	@	(4.00)	(238)	(4.00)	(238)	-
25	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	14,310	Bills	@	(8.00)	(114)	(12.00)	(172)	(57)
27	Total Delivery					$ 21,302		$ 24,766	$ 3,464
28	Total Full Service					$ 42,943		$ 47,363	$ 4,420
	ROA SERVICE								
	Delivery								
29	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
30	Distribution	-	MWh	@	0.093333	-	0.110796	-	-
	Provisions								
31	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
32	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(12.00)	-	-
34	Total Delivery					$ -		$ -	$ -
35	Total Full & ROA Service					$ 42,943		$ 47,363	$ 4,420

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Nighttime Savers (RPM)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 3 of 24
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	10,932	MWh	@	0.060410	$ 660	0.070978	$ 776	$ 116
2	Off-peak kWh	22,225	MWh	@	0.046196	1,027	0.053122	1,181	154
3	Super Off-peak kWh	34,772	MWh	@	0.037381	1,300	0.042863	1,490	191
	Capacity								
4	On-peak kWh	10,932	MWh	@	0.053506	585	0.046477	508	(77)
5	Off-peak kWh	22,225	MWh	@	0.040916	909	0.035541	790	(119)
6	Super Off-peak kWh	34,772	MWh	@	0.033109	1,151	0.028759	1,000	(151)
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	14,368	MWh	@	0.038335	551	0.046318	666	115
8	Off-peak kWh	35,741	MWh	@	0.035960	1,285	0.040953	1,464	178
9	Super Off-peak kWh	60,081	MWh	@	0.028890	1,736	0.033019	1,984	248
	Capacity								
10	On-peak kWh	14,368	MWh	@	0.033954	488	0.029494	424	(64)
11	Off-peak kWh	35,741	MWh	@	0.031850	1,138	0.027666	989	(150)
12	Super Off-peak kWh	60,081	MWh	@	0.025588	1,537	0.022227	1,335	(202)
	Provisions								
	Device Cycling								
13	AC Cycling	3,438	Bills	@	(5.00)	(17)	(5.00)	(17)	-
14	Back-Up Generator Pilot	-	Bills	@	-	-	-	-	-
15	Electric Water Tank Pilot	-	Bills	@	-	-	-	-	-
16	Peak Time Rewards	35	MWh	@	(0.50)	(17)	(0.50)	(17)	-
	Critical Peak Pricing								
17	Critical-peak Charge	7	MWh	@	1.00	7	1.00	7	-
18	Off-peak Credits	1,550	MWh	@	(0.006373)	(10)	(0.006008)	(9)	1
19	Annual PSCR Factor	178,119	MWh	@	0.013710	2,442	0.013710	2,442	-
20	Total Production					$ 14,773		$ 15,012	$ 239
	Transmission								
	Summer (June - Sept.)								
21	On-peak kWh	10,932	MWh	@	0.037988	$ 415	0.043399	$ 474	$ 59
22	Off-peak kWh	22,225	MWh	@	0.029049	646	0.033187	738	92
23	Super Off-peak kWh	34,772	MWh	@	0.023506	817	0.026855	934	116
	Winter (Oct. - May)								
24	On-peak kWh	14,368	MWh	@	0.024106	346	0.027540	396	49
25	Off-peak kWh	35,741	MWh	@	0.022613	808	0.025834	923	115
26	Super Off-peak kWh	60,081	MWh	@	0.018167	1,091	0.020755	1,247	155
27	Total Transmission					$ 4,124		$ 4,712	$ 587
	Delivery								
28	System Access	208,584	Bills	@	8.00	$ 1,669	8.00	$ 1,669	$ -
29	Separately Metered EV Charger	323	Bills	@	(8.00)	$ (3)	(8.00)	$ (3)	$ -
30	Distribution	178,119	MWh	@	0.093333	16,624	0.110796	19,735	3,111
	Provisions								
31	Senior Citizen (RSC)	45,312	Bills	@	(4.00)	(181)	(4.00)	(181)	-
32	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
33	Income Assistance (RIA)	4,176	Bills	@	(8.00)	(33)	(12.00)	(50)	(17)
34	Total Delivery					$ 18,076		$ 21,170	$ 3,094
35	Total Full Service					$ 36,973		$ 40,893	$ 3,920
	ROA SERVICE								
	Delivery								
36	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
37	Distribution	-	MWh	@	0.093333	-	0.110796	-	-
	Provisions								
38	Senior Citizen (RSC)	-	Bills	@	(4.00)	-	(4.00)	-	-
39	Low Income Credit (LIAC)	-	Bills	@	(42.00)	-	(42.00)	-	-
40	Income Assistance (RIA)	-	Bills	@	(8.00)	-	(12.00)	-	-
41	Total Delivery					$ -		$ -	$ -
42	Total Full & ROA Service					$ 36,973		$ 40,893	$ 3,920

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Non-Transmitting Meters (RSM)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 4 of 24
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c)	(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE									
	Production									
	Summer (June - Sept.)									
	Non-capacity									
1	First 600 kWh	20,927	MWh	@		0.033007	$ 691	0.038072	$ 797	$ 106
2	Excess kWh	14,961	MWh	@		0.060410	904	0.070978	1,062	158
	Capacity									
3	First 600 kWh	20,927	MWh	@		0.029234	612	0.025394	531	(80)
4	Excess kWh	14,961	MWh	@		0.053506	801	0.046477	695	(105)
	Winter (Oct. - May)									
5	Non-capacity All kWh	68,847	MWh	@		0.033007	2,272	0.038072	2,621	349
6	Capacity All kWh	68,847	MWh	@		0.029234	2,013	0.025394	1,748	(264)
7	Annual PSCR Factor	104,736	MWh	@		0.013710	1,436	0.013710	1,436	-
8	Total Production						$ 8,728		$ 8,891	$ 163
	Transmission									
	Summer (June - Sept.)									
9	First 600 kWh	20,927	MWh	@		0.020756	$ 434	0.023712	$ 496	$ 62
10	Excess kWh	14,961	MWh	@		0.037988	568	0.043399	649	81
	Winter (Oct. - May)									
11	All kWh	68,847	MWh	@		0.020756	1,429	0.023712	1,633	204
12	Total Transmission						$ 2,432		$ 2,778	$ 346
	Delivery									
13	System Access	126,913	Bills	@		8.00	$ 1,015	8.00	$ 1,015	$ -
14	Opt-out Fee	96,085	Bills	@		12.61	1,212	12.61	1,212	-
15	Distribution	104,736	MWh	@		0.093333	9,775	0.110796	11,604	1,829
	Provisions									
16	Senior Citizen (RSC)	37,199	Bills	@		(4.00)	(149)	(4.00)	(149)	-
17	Low Income Credit (LIAC)	-	Bills	@		(42.00)	-	(42.00)	-	-
18	Income Assistance (RIA)	3,684	Bills	@		(8.00)	(29)	(12.00)	(44)	(15)
19	Total Delivery						$ 11,824		$ 13,638	$ 1,814
20	Total Full Service						$ 22,984		$ 25,307	$ 2,324
	ROA SERVICE									
	Delivery									
21	System Access	-	Bills	@		8.00	$ -	8.00	$ -	$ -
22	Opt-out Fee	-	Bills	@		12.61	-	12.61	-	-
23	Distribution	-	MWh	@		0.093333	-	0.110796	-	-
	Provisions									
24	Senior Citizen (RSC)	-	Bills	@		(4.00)	-	(4.00)	-	-
25	Low Income Credit (LIAC)	-	Bills	@		(42.00)	-	(42.00)	-	-
26	Income Assistance (RIA)	-	Bills	@		(8.00)	-	(12.00)	-	-
27	Total Delivery						$ -		$ -	$ -
28	Total Full & ROA Service						$ 22,984		$ 25,307	$ 2,324

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Electric Heating (REH)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 5 of 24
Witness: MCGrondin
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	-	MWh	@		$ -	0.070978	$ -	$ -
2	Off-peak kWh	-	MWh	@		-	0.047444	-	-
	Capacity								
3	On-peak kWh	-	MWh	@		-	0.046477	-	-
4	Off-peak kWh	-	MWh	@		-	0.031811	-	-
	Winter (Oct. - May)								
	Non-capacity								
5	First 750 kWh	-	MWh	@		-	0.038333	-	-
6	Excess kWh	-	MWh	@		-	0.026810	-	-
	Capacity								
7	First 750 kWh	-	MWh	@		-	0.025719	-	-
8	Excess kWh	-	MWh	@		-	0.017774	-	-
	Provisions								
	Device Cycling								
9	AC Cycling	-	Bills	@		-	(5.00)	-	-
10	Back-Up Generator Pilot	-	Bills	@		-	-	-	-
11	Electric Water Tank Pilot	-	Bills	@		-	-	-	-
12	Peak Time Rewards	-	MWh	@		-	(0.50)	-	-
	Critical Peak Pricing								
13	Critical-peak Charge	-	MWh	@		-	1.00	-	-
14	Off-peak Credits	-	MWh	@		-	(0.006008)	-	-
15	Annual PSCR Factor	-	MWh	@		-	0.013710	-	-
16	Total Production					$ -		$ -	$ -
	Transmission								
	Summer (June - Sept.)								
17	On-peak kWh	-	MWh	@		$ -	0.043399	$ -	$ -
18	Off-peak kWh	-	MWh	@		-	0.029704	-	-
	Winter (Oct. - May)								
19	First 750 kWh	-	MWh	@		$ -	0.023983	$ -	$ -
20	Excess kWh	-	MWh	@		-	0.016668	-	-
21	Total Transmission					$ -		$ -	$ -
	Delivery								
22	System Access	-	Bills	@		$ -	8.00	$ -	$ -
23	Distribution	-	MWh	@		-	0.110796	-	-
	Provisions								
24	Senior Citizen (RSC)	-	Bills	@		-	(4.00)	-	-
25	Low Income Credit (LIAC)	-	Bills	@		-	(42.00)	-	-
26	Income Assistance (RIA)	-	Bills	@		-	(12.00)	-	-
27	Total Delivery					$ -		$ -	$ -
28	Total Full Service					$ -		$ -	$ -

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Energy-only (GS)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	1,475,694	MWh	@	0.046363	$ 68,417	0.053402	$ 78,805	$ 10,388
2	Capacity All kWh	1,475,694	MWh	@	0.035056	51,731	0.028634	42,255	(9,476)
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,612,749	MWh	@	0.034013	88,866	0.039179	102,365	13,498
4	Capacity All kWh	2,612,749	MWh	@	0.025987	67,897	0.021227	55,460	(12,437)
5	Annual PSCR Factor	4,088,442	MWh	@	0.013710	56,053	0.013710	56,053	-
6	Total Production					$ 332,964		$ 334,938	$ 1,974
	Transmission								
	Summer (June - Sept.)								
7	All kWh	1,475,694	MWh	@	0.026688	$ 39,384	0.029462	$ 43,476	$ 4,093
	Winter (Oct. - May)								
8	All kWh	2,612,749	MWh	@	0.019784	51,690	0.021840	57,062	5,372
9	Total Transmission					$ 91,074		$ 100,538	$ 9,465
	Delivery								
10	System Access	2,493,080	Bills	@	20.00	$ 49,862	20.00	$ 49,862	$ -
11	Distribution	4,088,442	MWh	@	0.069433	283,871	0.084400	345,066	61,195
	Provisions								
12	Education GEI	92,452	MWh	@	(0.001000)	(92)	(0.001179)	(109)	(17)
13	Total Delivery					$ 333,640		$ 394,818	$ 61,178
14	Total Full Service					$ 757,678		$ 830,295	$ 72,617
	ROA SERVICE								
	Delivery								
15	System Access	936	Bills	@	20.00	$ 19	20.00	$ 19	$ -
16	Distribution	17,123	MWh	@	0.069433	1,189	0.084400	1,445	256
	Provisions								
17	Education GEI	10,347	MWh	@	(0.001000)	(10)	(0.001179)	(12)	(2)
18	Total Delivery					$ 1,197		$ 1,452	$ 254
19	Total Full & ROA Service					$ 758,875		$ 831,746	$ 72,871

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Time-of-Use (GSTU)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c)	(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE									
	Production									
	Summer (June - Sept.)									
	Non-capacity									
1	On-peak kWh	17,753	MWh	@		0.062830	$ 1,115	0.072246	$ 1,283	$ 167
2	Mid-peak kWh	13,471	MWh	@		0.048934	659	0.056054	755	96
3	Off-peak kWh	5,121	MWh	@		0.036694	188	0.042085	216	28
	Capacity									
4	On-peak kWh	17,753	MWh	@		0.047982	852	0.039193	696	(156)
5	Mid-peak kWh	13,471	MWh	@		0.037369	503	0.030524	411	(92)
6	Off-peak kWh	5,121	MWh	@		0.028063	144	0.022923	117	(26)
	Winter (Oct. - May)									
	Non-capacity									
7	On-peak kWh	30,963	MWh	@		0.037107	1,149	0.042836	1,326	177
8	Off-peak kWh	34,238	MWh	@		0.030029	1,028	0.034424	1,179	150
	Capacity									
9	On-peak kWh	30,963	MWh	@		0.028428	880	0.023221	719	(161)
10	Off-peak kWh	34,238	MWh	@		0.022961	786	0.018755	642	(144)
	Provisions									
11	Interruptible (GSI)	-	MWh	@		(0.021695)	-	(0.021742)	-	-
12	Annual PSCR Factor	101,547	MWh	@		0.013710	1,392	0.013710	1,392	-
13	Total Production						$ 8,697		$ 8,736	$ 39
	Transmission									
	Summer (June - Sept.)									
14	On-peak kWh	17,753	MWh	@		0.036529	$ 649	0.040325	$ 716	$ 67
15	Mid-peak kWh	13,471	MWh	@		0.028449	383	0.031406	423	40
16	Off-peak kWh	5,121	MWh	@		0.021365	109	0.023585	121	11
	Winter (Oct. - May)									
17	On-peak kWh	30,963	MWh	@		0.021643	670	0.023892	740	70
18	Off-peak kWh	34,238	MWh	@		0.017480	598	0.019297	661	62
19	Total Transmission						$ 2,410		$ 2,660	$ 250
	Delivery									
20	System Access	27,204	Bills	@		20.00	$ 544	20.00	$ 544	$ -
21	Distribution	101,547	MWh	@		0.069433	7,051	0.084400	8,571	1,520
	Provisions									
22	Education GEI	-	MWh	@		(0.001000)	-	(0.001179)	-	-
23	Total Delivery						$ 7,595		$ 9,115	$ 1,520
24	Total Full Service						$ 18,702		$ 20,511	$ 1,809

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Demand (GSD)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 8 of 24
Witness: MCGrondin
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Peak kW	2,805	MW	@	6.10	$ 17,098	10.53	$ 29,532	$ 12,434
2	All kWh	1,015,135	MWh	@	0.032526	33,018	0.030382	30,842	(2,176)
	Capacity								
3	Peak kW	2,805	MW	@	10.17	28,533	8.33	23,366	(5,167)
4	All kWh	1,015,135	MWh	@	-	-	-	-	-
	Winter (Oct. - May)								
	Non-capacity								
5	Peak kW	5,095	MW	@	2.89	14,701	4.98	25,393	10,692
6	All kWh	1,838,946	MWh	@	0.023861	43,880	0.022290	40,991	(2,889)
	Capacity								
7	Peak kW	5,095	MW	@	9.05	46,127	7.41	37,775	(8,353)
8	All kWh	1,838,946	MWh	@	-	-	-	-	-
9	Power Factor Adjustment					150		(28)	(178)
	Provisions								
10	Interruptible (GSI)-Summer	28	MW	@	(8.50)	(238)	(8.50)	(238)	-
11	Interruptible (GSI)-Winter	51	MW	@	(7.50)	(383)	(7.50)	(383)	-
12	Annual PSCR Factor	2,854,081	MWh	@	0.013710	39,129	0.013710	39,129	-
13	Total Production					$ 222,015		$ 226,379	$ 4,363
	Transmission								
	Summer (June - Sept.)								
14	Peak kW	2,805	MW	@	8.00	$ 22,446	8.85	$ 24,826	$ 2,380
	Winter (Oct. - May)								
15	Peak kW	5,095	MW	@	7.12	36,287	7.88	40,135	3,848
16	Total Transmission					$ 58,732		$ 64,960	$ 6,228
	Delivery								
17	System Access	237,828	Bills	@	30.00	$ 7,135	30.00	$ 7,135	$ -
18	Peak kW	7,900	MW	@	1.00	7,900	1.00	7,900	-
19	Distribution	2,854,081	MWh	@	0.057650	164,537	0.068248	194,786	30,248
20	Power Factor Adjustment					243		(30)	(274)
	Provisions								
21	Education GEI	122,230	MWh	@	(0.000820)	(100)	(0.000956)	(117)	(17)
22	Total Delivery					$ 179,716		$ 209,674	$ 29,958
23	Total Full Service					$ 460,464		$ 501,013	$ 40,549
	ROA SERVICE								
	Delivery								
24	System Access	5,691	Bills	@	30.00	$ 171	30.00	$ 171	$ -
25	Peak kW	240	MW	@	1.00	240	1.00	240	-
26	Distribution	167,933	MWh	@	0.057650	9,681	0.068248	11,461	1,780
27	Power Factor Adjustment					15		1	(14)
	Provisions								
28	Education GEI	67,642	MWh	@	(0.000820)	(55)	(0.000956)	(65)	(9)
29	Total Delivery					$ 10,052		$ 11,809	$ 1,757
30	Total Full & ROA Service					$ 470,515		$ 512,822	$ 42,306

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 1 (GP VL 1)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(c)	(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE									
	Production									
	Summer (June - Sept.)									
1	Non-capacity All kWh	652	MWh	@		0.043974	$ 29	0.049246	$ 32	$ 3
2	Capacity All kWh	652	MWh	@		0.027595	18	0.021414	14	(4)
	Winter (Oct. - May)									
3	Non-capacity All kWh	1,422	MWh	@		0.032261	46	0.036130	51	6
4	Capacity All kWh	1,422	MWh	@		0.021049	30	0.016334	23	(7)
5	Power Factor Adjustment						2		1	(1)
6	Annual PSCR Factor	2,074	MWh	@		0.013710	28	0.013710	28	-
7	Total Production						$ 153		$ 150	$ (3)
	Transmission									
	Summer (June - Sept.)									
8	All kWh	652	MWh	@		0.023364	$ 15	0.025183	$ 16	$ 1
	Winter (Oct. - May)									
9	All kWh	1,422	MWh	@		0.017822	25	0.019210	27	2
10	Total Transmission						$ 41		$ 44	$ 3
	Delivery									
11	System Access	47	Bills	@		100.00	$ 5	100.00	$ 5	$ -
12	Distribution	2,074	MWh	@		0.006957	14	0.009289	19	5
13	Substation Ownership Credit	13	MWh	@		(0.004093)	(0)	(0.005427)	(0)	(0)
14	Power Factor Adjustment						0		0	(0)
	Provisions									
15	Education GEI	-	MWh	@		(0.000578)	-	(0.000649)	-	-
16	Total Delivery						$ 19		$ 24	$ 5
17	Total Full Service						$ 213		$ 218	$ 5
	ROA SERVICE									
	Delivery									
18	System Access	-	Bills	@		100.00	$ -	100.00	$ -	$ -
19	Distribution	-	MWh	@		0.006957	-	0.009289	-	-
20	Substation Ownership Credit	-	MWh	@		(0.004093)	-	(0.005427)	-	-
21	Power Factor Adjustment						-		-	-
	Provisions									
22	Education GEI	-	MWh	@		(0.000578)	-	(0.000649)	-	-
23	Total Delivery						$ -		$ -	$ -
24	Total Full & ROA Service						$ 213		$ 218	$ 5

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 2 (GP VL 2)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	10,326	MWh	@	0.044489	$ 459	0.049837	$ 515	$ 55
2	Capacity All kWh	10,326	MWh	@	0.027998	289	0.021722	224	(65)
	Winter (Oct. - May)								
3	Non-capacity All kWh	18,151	MWh	@	0.032638	592	0.036563	664	71
4	Capacity All kWh	18,151	MWh	@	0.021357	388	0.016570	301	(87)
5	Power Factor Adjustment					45		34	(12)
6	Annual PSCR Factor	28,476	MWh	@	0.013710	390	0.013710	390	-
7	Total Production					$ 2,164		$ 2,127	$ (37)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	10,326	MWh	@	0.023706	$ 245	0.025546	$ 264	$ 19
	Winter (Oct. - May)								
9	All kWh	18,151	MWh	@	0.018083	328	0.019486	354	25
10	Total Transmission					$ 573		$ 617	$ 44
	Delivery								
11	System Access	434	Bills	@	100.00	$ 43	100.00	$ 43	$ -
12	Distribution	28,476	MWh	@	0.010996	313	0.013754	392	79
13	Substation Ownership Credit	6,613	MWh	@	(0.004513)	(30)	(0.005083)	(34)	(4)
14	Power Factor Adjustment					7		7	(0)
	Provisions								
15	Education GEI	-	MWh	@	(0.000578)	-	(0.000649)	-	-
16	Total Delivery					$ 334		$ 408	$ 74
17	Total Full Service					$ 3,071		$ 3,153	$ 82
	ROA SERVICE								
	Delivery								
18	System Access	24	Bills	@	100.00	$ 2	100.00	$ 2	$ -
19	Distribution	1,168	MWh	@	0.010996	13	0.013754	16	3
20	Substation Ownership Credit	-	MWh	@	(0.004513)	-	(0.005083)	-	-
21	Power Factor Adjustment					(0)		(0)	0
	Provisions								
22	Education GEI	-	MWh	@	(0.000578)	-	(0.000649)	-	-
23	Total Delivery					$ 15		$ 18	$ 3
24	Total Full & ROA Service					$ 3,087		$ 3,172	$ 85

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy-only Voltage Level 3 (GP VL 3)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh	218,116	MWh	@	0.044937	$ 9,802	0.050335	$ 10,979	$ 1,177
2	Capacity All kWh	218,116	MWh	@	0.028442	6,204	0.022039	4,807	(1,397)
	Winter (Oct. - May)								
3	Non-capacity All kWh	393,234	MWh	@	0.032967	12,964	0.036928	14,521	1,558
4	Capacity All kWh	393,234	MWh	@	0.021696	8,531	0.016811	6,611	(1,921)
5	Power Factor Adjustment					471		310	(161)
6	Annual PSCR Factor	611,350	MWh	@	0.013710	8,382	0.013710	8,382	-
7	Total Production					$ 46,353		$ 45,610	$ (743)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	218,116	MWh	@	0.024082	$ 5,253	0.025918	$ 5,653	$ 401
	Winter (Oct. - May)								
9	All kWh	393,234	MWh	@	0.018370	7,224	0.019771	7,774	551
10	Total Transmission					$ 12,476		$ 13,428	$ 951
	Delivery								
11	System Access	15,025	Bills	@	100.00	$ 1,503	100.00	$ 1,503	$ -
12	Distribution	611,350	MWh	@	0.024415	14,926	0.030543	18,673	3,747
13	Power Factor Adjustment					187		157	(31)
	Provisions								
14	Education GEI	86,519	MWh	@	(0.000578)	(50)	(0.000649)	(56)	(6)
15	Total Delivery					$ 16,566		$ 20,276	$ 3,710
16	Total Full Service					$ 75,395		$ 79,313	$ 3,918
	ROA SERVICE								
	Delivery								
17	System Access	526	Bills	@	100.00	$ 53	100.00	$ 53	$ -
18	Distribution	69,541	MWh	@	0.024415	1,698	0.030543	2,124	426
19	Power Factor Adjustment					5		(1)	(7)
	Provisions								
20	Education GEI	35,838	MWh	@	(0.000578)	(21)	(0.000649)	(23)	(3)
21	Total Delivery					$ 1,735		$ 2,152	$ 417
22	Total Full & ROA Service					$ 77,129		$ 81,465	$ 4,335

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 1 (GPD VL 1)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	675	MW	@	5.96	$ 4,024	9.60	$ 6,480	$ 2,456
2	On-peak kWh	87,584	MWh	@	0.040427	3,541	0.039617	3,470	(71)
3	Off-peak kWh	298,780	MWh	@	0.026219	7,834	0.025470	7,610	(224)
4	Capacity On-peak kW	675	MW	@	10.06	6,794	8.31	5,612	(1,182)
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,371	MW	@	5.15	7,059	8.29	11,367	4,308
6	On-peak kWh	177,927	MWh	@	0.025351	4,511	0.025027	4,453	(58)
7	Off-peak kWh	609,305	MWh	@	0.022012	13,412	0.021398	13,038	(374)
8	Capacity On-peak kW	1,371	MW	@	9.33	12,794	7.71	10,568	(2,226)
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	56	MW	@	(8.50)	(478)	(8.50)	(478)	-
11	Winter Contracted kW	112	MW	@	(7.50)	(844)	(7.50)	(844)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.029081	-	0.034321	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.026985	-	0.031388	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.031296	-	-
16	Summer Transmission	-	MWh		-	-	0.017877	-	-
17	Winter Capacity	-	MWh		-	-	0.027863	-	-
18	Winter Transmission	-	MWh		-	-	0.016585	-	-
19	Critical Peak Event	-	MWh		-	-	1.00	-	-
20	Power Factor Adjustment					(123)		(115)	8
21	Annual PSCR Factor	1,173,597	MWh	@	0.013710	16,090	0.013710	16,090	-
22	Total Production					$ 74,614		$ 77,251	$ 2,637
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	675	MW	@	9.13	$ 6,161	10.23	$ 6,907	$ 746
	Winter (Oct. - May)								
24	On-peak kW	1,371	MW	@	8.50	11,647	9.52	13,057	1,410
25	Total Transmission					$ 17,808		$ 19,964	$ 2,155
	Delivery								
26	System Access	302	Bills	@	200.00	$ 60	200.00	$ 60	$ -
27	Maximum kW	2,511	MW	@	2.37	5,957	3.28	8,225	2,268
28	Substation Ownership	33	MW	@	(1.82)	(61)	(2.51)	(84)	(23)
29	Distribution	1,173,597	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(12)		(15)	(3)
	Provisions								
31	Education GEI	-	MWh	@	(0.000205)	-	(0.000226)	-	-
32	Total Delivery					$ 5,944		$ 8,186	$ 2,242
33	Total Full Service					$ 98,366		$ 105,401	$ 7,035
	ROA SERVICE								
	Delivery								
34	System Access	167	Bills	@	200.00	$ 33	200.00	$ 33	$ -
35	Maximum kW	2,357	MW	@	2.37	5,591	3.28	7,720	2,129
36	Substation Ownership	175	MW	@	(1.82)	(318)	(2.51)	(438)	(120)
37	Distribution	1,223,357	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					(13)		(87)	(74)
	Provisions								
39	Education GEI	2,998	MWh	@	(0.000205)	(1)	(0.000226)	(1)	(0)
40	Total Delivery					$ 5,292		$ 7,227	$ 1,935
41	Total Full & ROA Service					$ 103,658		$ 112,628	$ 8,969

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 2 (GPD VL 2)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 13 of 24
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	896	MW	@	6.03	$ 5,403	9.71	$ 8,703	$ 3,300
2	On-peak kWh	126,310	MWh	@	0.040900	5,166	0.040092	5,064	(102)
3	Off-peak kWh	374,051	MWh	@	0.026526	9,922	0.025775	9,641	(281)
4	Capacity On-peak kW	896	MW	@	10.21	9,150	8.43	7,556	(1,593)
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,798	MW	@	5.21	9,366	8.39	15,087	5,721
6	On-peak kWh	249,186	MWh	@	0.025648	6,391	0.025327	6,311	(80)
7	Off-peak kWh	755,561	MWh	@	0.022270	16,826	0.021655	16,362	(465)
8	Capacity On-peak kW	1,798	MW	@	9.47	17,024	7.82	14,059	(2,965)
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	40	MW	@	(8.50)	(342)	(8.50)	(342)	-
11	Winter Contracted kW	80	MW	@	(7.50)	(603)	(7.50)	(603)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.031449	-	0.035859	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.029198	-	0.032876	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.032495	-	-
16	Summer Transmission	-	MWh		-	-	0.018586	-	-
17	Winter Capacity	-	MWh		-	-	0.029009	-	-
18	Winter Transmission	-	MWh		-	-	0.009256	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					(105)		84	190
21	Annual PSCR Factor	1,505,108	MWh	@	0.013710	20,635	0.013710	20,635	-
22	Total Production					$ 98,834		$ 102,559	$ 3,725
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	896	MW	@	9.26	$ 8,297	10.38	$ 9,300	$ 1,002
	Winter (Oct. - May)								
24	On-peak kW	1,798	MW	@	8.62	15,498	9.66	17,371	1,872
25	Total Transmission					$ 23,796		$ 26,670	$ 2,875
	Delivery								
26	System Access	725	Bills	@	200.00	$ 145	200.00	$ 145	$ -
27	Maximum kW	3,112	MW	@	3.61	11,244	4.45	13,864	2,620
28	Substation Ownership	277	MW	@	(1.93)	(534)	(2.16)	(597)	(62)
29	Distribution	1,505,108	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(14)		14	28
	Provisions								
31	Education GEI	28,720	MWh	@	(0.000205)	(6)	(0.000226)	(6)	(1)
32	Total Delivery					$ 10,834		$ 13,419	$ 2,585
33	Total Full Service					$ 133,463		$ 142,649	$ 9,186
	ROA SERVICE								
	Delivery								
34	System Access	443	Bills	@	200.00	$ 89	200.00	$ 89	$ -
35	Maximum kW	2,401	MW	@	3.61	8,675	4.45	10,697	2,022
36	Substation Ownership	308	MW	@	(1.93)	(595)	(2.16)	(665)	(69)
37	Distribution	1,098,601	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					16		5	(11)
	Provisions								
39	Education GEI	62,735	MWh	@	(0.000205)	(13)	(0.000226)	(14)	(1)
40	Total Delivery					$ 8,172		$ 10,112	$ 1,940
41	Total Full & ROA Service					$ 141,635		$ 152,760	$ 11,125

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Demand Voltage Level 3 (GPD VL 3)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 14 of 24
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kW	1,336	MW	@	6.09	$ 8,134	9.81	$ 13,102	$ 4,968
2	On-peak kWh	182,852	MWh	@	0.041312	7,554	0.040492	7,404	(150)
3	Off-peak kWh	518,199	MWh	@	0.026793	13,884	0.026033	13,490	(394)
4	Capacity On-peak kW	1,336	MW	@	10.37	13,850	8.56	11,427	(2,423)
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	2,545	MW	@	5.26	13,384	8.47	21,565	8,181
6	On-peak kWh	345,561	MWh	@	0.025907	8,952	0.025580	8,840	(113)
7	Off-peak kWh	992,414	MWh	@	0.022495	22,324	0.021871	21,705	(619)
8	Capacity On-peak kW	2,545	MW	@	9.62	24,478	7.93	20,187	(4,291)
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	4	MW	@	(8.50)	(32)	(8.50)	(32)	-
11	Winter Contracted kW	8	MW	@	(7.50)	(57)	(7.50)	(57)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.033010	-	0.038856	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.031900	-	0.036967	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.034989	-	-
16	Summer Transmission	-	MWh		-	-	0.020061	-	-
17	Winter Capacity	-	MWh		-	-	0.031205	-	-
18	Winter Transmission	-	MWh		-	-	0.018641	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					77		(30)	(107)
21	Annual PSCR Factor	2,039,025	MWh	@	0.013710	27,955	0.013710	27,955	-
22	Total Production					$ 140,504		$ 145,555	$ 5,051
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	1,336	MW	@	9.41	$ 12,568	10.53	$ 14,064	$ 1,496
	Winter (Oct. - May)								
24	On-peak kW	2,545	MW	@	8.76	22,290	9.80	24,942	2,652
25	Total Transmission					$ 34,858		$ 39,005	$ 4,147
	Delivery								
26	System Access	7,348	Bills	@	200.00	$ 1,470	200.00	$ 1,470	$ -
27	Maximum kW	4,970	MW	@	6.68	33,197	8.12	40,371	7,174
28	Distribution	2,039,025	MWh	@	-	-	-	-	-
29	Power Factor Adjustment					23		(10)	(33)
	Provisions								
30	Education GEI	94,669	MWh	@	(0.000205)	(19)	(0.000226)	(21)	(2)
31	Total Delivery					$ 34,670		$ 41,809	$ 7,139
32	Total Full Service					$ 210,032		$ 226,370	$ 16,337
	ROA SERVICE								
	Delivery								
33	System Access	3,890	Bills	@	200.00	$ 778	200.00	$ 778	$ -
34	Maximum kW	2,721	MW	@	6.68	18,178	8.12	22,106	3,928
35	Distribution	1,010,718	MWh	@	-	-	-	-	-
36	Power Factor Adjustment					40		(11)	(51)
	Provisions								
37	Education GEI	151,645	MWh	@	(0.000205)	(31)	(0.000226)	(34)	(3)
38	Total Delivery					$ 18,964		$ 22,839	$ 3,874
39	Total Full & ROA Service					$ 228,997		$ 249,208	$ 20,212

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 1 (GPTU VL 1)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	8,211	MWh	@	0.061877	$ 508	0.073102	$ 600	$ 92
2	Mid-peak kWh	9,157	MWh	@	0.055068	504	0.064418	590	86
3	Low-peak kWh	43,803	MWh	@	0.044513	1,950	0.051967	2,276	326
4	Off-peak kWh	59,339	MWh	@	0.033174	1,969	0.038560	2,288	320
	Capacity								
5	High-peak kWh	8,211	MWh	@	0.035267	290	0.029511	242	(47)
6	Mid-peak kWh	9,157	MWh	@	0.031400	288	0.026275	241	(47)
7	Low-peak kWh	43,803	MWh	@	0.025306	1,108	0.021175	928	(181)
8	Off-peak kWh	59,339	MWh	@	0.018927	1,123	0.015838	940	(183)
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	12,758	MWh	@	0.039842	508	0.049055	626	118
10	Mid-peak kWh	13,026	MWh	@	0.036938	481	0.043620	568	87
11	Off-peak kWh	171,957	MWh	@	0.031011	5,333	0.035971	6,185	853
	Capacity								
12	High-peak kWh	12,758	MWh	@	0.022720	290	0.019011	243	(47)
13	Mid-peak kWh	13,026	MWh	@	0.021035	274	0.017601	229	(45)
14	Off-peak kWh	171,957	MWh	@	0.017499	3,009	0.014643	2,518	(491)
15	Power Factor Adjustment					29		(6)	(35)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	5	MW	@	(8.50)	-	(8.50)	(44)	(44)
17	Winter Contracted kW	10	MW	@	(7.50)	-	(7.50)	(78)	(78)
18	Annual PSCR Factor	318,251	MWh	@	0.013710	4,363	0.013710	4,363	-
19	Total Production					$ 22,026		$ 22,709	$ 683
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	8,211	MWh	@	0.030861	$ 253	0.035110	$ 288	$ 35
21	Mid-peak kWh	9,157	MWh	@	0.027477	252	0.031260	286	35
22	Low-peak kWh	43,803	MWh	@	0.022144	970	0.025193	1,104	134
23	Off-peak kWh	59,339	MWh	@	0.016563	983	0.018843	1,118	135
24	Winter (Oct. - May)								
25	High-peak kWh	12,758	MWh	@	0.019881	254	0.022618	289	35
26	Mid-peak kWh	13,026	MWh	@	0.018407	240	0.020941	273	33
27	Off-peak kWh	171,957	MWh	@	0.015313	2,633	0.017421	2,996	363
28	Total Transmission					$ 5,584		$ 6,353	$ 769
	Delivery								
29	System Access	275	Bills	@	200.00	$ 55	200.00	$ 55	$ -
30	Maximum kW	888	MW	@	2.37	2,107	3.28	2,909	802
31	Substation Ownership	-	MW	@	(1.82)	-	(2.51)	-	-
32	Distribution	318,251	MWh	@	-	-	-	-	-
33	Power Factor Adjustment					3		(1)	(4)
	Provisions								
34	Education GEI	21,125	MWh	@	(0.000205)	(4)	(0.000226)	(5)	(0)
35	Total Delivery					$ 2,161		$ 2,958	$ 797
36	Total Full Service					$ 29,771		$ 32,020	$ 2,249

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 2 (GPTU VL 2)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	10,362	MWh	@	0.062601	$ 649	0.073979	$ 767	$ 118
2	Mid-peak kWh	11,722	MWh	@	0.055712	653	0.065191	764	111
3	Low-peak kWh	54,506	MWh	@	0.045034	2,455	0.052590	2,866	412
4	Off-peak kWh	69,527	MWh	@	0.033562	2,333	0.039023	2,713	380
	Capacity								
5	High-peak kWh	10,362	MWh	@	0.035782	371	0.029936	310	(61)
6	Mid-peak kWh	11,722	MWh	@	0.031859	373	0.026653	312	(61)
7	Low-peak kWh	54,506	MWh	@	0.025675	1,399	0.021480	1,171	(229)
8	Off-peak kWh	69,527	MWh	@	0.019204	1,335	0.016066	1,117	(218)
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	17,772	MWh	@	0.040309	716	0.049643	882	166
10	Mid-peak kWh	17,858	MWh	@	0.037370	667	0.044143	788	121
11	Off-peak kWh	217,297	MWh	@	0.031374	6,817	0.036402	7,910	1,093
	Capacity								
12	High-peak kWh	17,772	MWh	@	0.023051	410	0.019285	343	(67)
13	Mid-peak kWh	17,858	MWh	@	0.021342	381	0.017855	319	(62)
14	Off-peak kWh	217,297	MWh	@	0.017754	3,858	0.014854	3,228	(630)
15	Power Factor Adjustment					(10)		34	44
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	399,045	MWh	@	0.013710	5,471	0.013710	5,471	-
19	Total Production					$ 27,880		$ 28,996	$ 1,116
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	10,362	MWh	@	0.031312	$ 324	0.035616	$ 369	$ 45
21	Mid-peak kWh	11,722	MWh	@	0.027879	327	0.031710	372	45
22	Low-peak kWh	54,506	MWh	@	0.022468	1,225	0.025556	1,393	168
23	Off-peak kWh	69,527	MWh	@	0.016805	1,168	0.019115	1,329	161
	Winter (Oct. - May)								
24	High-peak kWh	17,772	MWh	@	0.020172	358	0.022944	408	49
25	Mid-peak kWh	17,858	MWh	@	0.018676	334	0.021243	379	46
26	Off-peak kWh	217,297	MWh	@	0.015536	3,376	0.017672	3,840	464
27	Total Transmission					$ 7,112		$ 8,090	$ 978
	Delivery								
28	System Access	934	Bills	@	200.00	$ 187	200.00	$ 187	$ -
29	Maximum kW	1,308	MW	@	3.61	4,726	4.45	5,827	1,101
30	Substation Ownership	227	MW	@	(1.93)	(438)	(2.16)	(489)	(51)
31	Distribution	399,045	MWh	@	-	-	-	-	-
32	Power Factor Adjustment					(2)		8	10
	Provisions								
33	Education GEI	18,438	MWh	@	(0.000205)	(4)	(0.000226)	(4)	(0)
34	Total Delivery					$ 4,469		$ 5,529	$ 1,059
35	Total Full Service					$ 39,461		$ 42,614	$ 3,153

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Time-of-Use Voltage Level 3 (GPTU VL 3)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 17 of 24
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	102,977	MWh	@	0.063232	$ 6,511	0.074717	$ 7,694	$ 1,183
2	Mid-peak kWh	114,778	MWh	@	0.056274	6,459	0.065842	7,557	1,098
3	Low-peak kWh	516,760	MWh	@	0.045488	23,506	0.053115	27,448	3,941
4	Off-peak kWh	636,627	MWh	@	0.033901	21,582	0.039413	25,091	3,509
	Capacity								
5	High-peak kWh	102,977	MWh	@	0.036350	3,743	0.030372	3,128	(616)
6	Mid-peak kWh	114,778	MWh	@	0.032364	3,715	0.027042	3,104	(611)
7	Low-peak kWh	516,760	MWh	@	0.026083	13,478	0.021794	11,262	(2,216)
8	Off-peak kWh	636,627	MWh	@	0.019509	12,420	0.016301	10,377	(2,042)
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	158,324	MWh	@	0.040715	6,446	0.050139	7,938	1,492
10	Mid-peak kWh	159,903	MWh	@	0.037747	6,036	0.044584	7,129	1,093
11	Off-peak kWh	1,938,863	MWh	@	0.031690	61,442	0.036765	71,283	9,841
	Capacity								
12	High-peak kWh	158,324	MWh	@	0.023417	3,707	0.019566	3,098	(610)
13	Mid-peak kWh	159,903	MWh	@	0.021680	3,467	0.018115	2,897	(570)
14	Off-peak kWh	1,938,863	MWh	@	0.018036	34,970	0.015070	29,219	(5,750)
15	Power Factor Adjustment					488		305	(182)
	Provisions								
	Interruptible GI								
16	Summer Contracted kW	-	MW	@	(8.50)	-	(8.50)	-	-
17	Winter Contracted kW	-	MW	@	(7.50)	-	(7.50)	-	-
18	Annual PSCR Factor	3,628,231	MWh	@	0.013710	49,743	0.013710	49,743	-
19	Total Production					$ 257,714		$ 267,274	$ 9,560
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	102,977	MWh	@	0.031809	$ 3,276	0.036135	$ 3,721	$ 446
21	Mid-peak kWh	114,778	MWh	@	0.028321	3,251	0.032173	3,693	442
22	Low-peak kWh	516,760	MWh	@	0.022824	11,795	0.025929	13,399	1,604
23	Off-peak kWh	636,627	MWh	@	0.017071	10,868	0.019393	12,346	1,478
	Winter (Oct. - May)								
24	High-peak kWh	158,324	MWh	@	0.020492	3,244	0.023279	3,686	441
25	Mid-peak kWh	159,903	MWh	@	0.018972	3,034	0.021552	3,446	413
26	Off-peak kWh	1,938,863	MWh	@	0.015783	30,601	0.017930	34,763	4,162
27	Total Transmission					$ 66,068		$ 75,054	$ 8,986
	Delivery								
28	System Access	19,143	Bills	@	200.00	$ 3,829	200.00	$ 3,829	$ -
29	Maximum kW	11,453	MW	@	6.68	76,509	8.12	93,043	16,534
30	Distribution	3,628,231	MWh	@	-	-	-	-	-
31	Power Factor Adjustment					180		131	(49)
	Provisions								
32	Education GEI	293,311	MWh	@	(0.000205)	(60)	(0.000226)	(66)	(6)
33	Total Delivery					$ 80,458		$ 96,936	$ 16,479
34	Total Full Service					$ 404,239		$ 439,264	$ 35,025

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 1 (EIP VL 1)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	236	MWh	@	0.099498	$ 23	0.114162	$ 27	$ 3
2	High-peak kWh	6,808	MWh	@	0.066332	452	0.076108	518	67
3	Mid-peak kWh	7,066	MWh	@	0.059487	420	0.067855	479	59
4	Low-peak kWh	46,619	MWh	@	0.047278	2,204	0.054213	2,527	323
5	Off-peak kWh	61,972	MWh	@	0.034619	2,145	0.039053	2,420	275
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	236	MWh	@	0.040218	9	0.033487	8	(2)
8	High-peak kWh	6,808	MWh	@	0.026812	183	0.022325	152	(31)
9	Mid-peak kWh	7,066	MWh	@	0.023872	169	0.019877	140	(28)
10	Low-peak kWh	46,619	MWh	@	0.019239	897	0.016019	747	(150)
11	Off-peak kWh	61,972	MWh	@	0.014390	892	0.011981	743	(149)
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	647	MWh	@	0.062127	40	0.074613	48	8
13	High-peak kWh	13,911	MWh	@	0.041418	576	0.049742	692	116
14	Mid-peak kWh	14,556	MWh	@	0.038779	564	0.044559	649	84
15	Off-peak kWh	179,592	MWh	@	0.032609	5,856	0.036992	6,643	787
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	647	MWh	@	0.025909	17	0.021573	14	(3)
18	High-peak kWh	13,911	MWh	@	0.017272	240	0.014382	200	(40)
19	Mid-peak kWh	14,556	MWh	@	0.015992	233	0.013315	194	(39)
20	Off-peak kWh	179,592	MWh	@	0.013303	2,389	0.011077	1,989	(400)
21	Power Factor Adjustment					7		2	(4)
22	Interruptible Credit	331,407	MWh	@	(0.008461)	(2,804)	(0.008502)	(2,818)	(13)
23	Annual PSCR Factor	331,407	MWh	@	0.013710	4,544	0.013710	4,544	-
24	Total Production					$ 19,056		$ 19,920	$ 863
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	236	MWh	@	0.041546	$ 10	0.046940	$ 11	$ 1
26	High-peak kWh	6,808	MWh	@	0.027698	189	0.031294	213	24
27	Mid-peak kWh	7,066	MWh	@	0.024660	174	0.027862	197	23
28	Low-peak kWh	46,619	MWh	@	0.019874	927	0.022455	1,047	120
29	Off-peak kWh	61,972	MWh	@	0.014865	921	0.016795	1,041	120
	Winter (Oct. - May)								
30	Critical-peak kWh	647	MWh	@	0.026765	17	0.030240	20	2
31	High-peak kWh	13,911	MWh	@	0.017843	248	0.020160	280	32
32	Mid-peak kWh	14,556	MWh	@	0.016520	240	0.018665	272	31
33	Off-peak kWh	179,592	MWh	@	0.013743	2,468	0.015527	2,789	320
34	Total Transmission					$ 5,194		$ 5,869	$ 674
	Delivery								
35	System Access	58	Bills	@	200.00	$ 12	200.00	$ 12	$ -
36	Maximum kW	752	MW	@	2.37	1,783	3.28	2,462	679
37	Substation Ownership	-	MW	@	(1.82)	-	(2.51)	-	-
38	Power Factor Adjustment					1		0	(0)
39	Distribution	331,407	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,795		$ 2,474	$ 679
41	Total Full Service					$ 26,046		$ 28,263	$ 2,217

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 2 (EIP VL 2)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	34	MWh	@	0.100662	$ 3	0.115532	$ 4	$ 1
2	High-peak kWh	791	MWh	@	0.067108	53	0.077021	61	8
3	Mid-peak kWh	893	MWh	@	0.060183	54	0.068669	61	8
4	Low-peak kWh	7,257	MWh	@	0.047832	347	0.054864	398	51
5	Off-peak kWh	10,112	MWh	@	0.035024	354	0.039521	400	45
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	34	MWh	@	0.040805	1	0.033969	1	(0)
8	High-peak kWh	791	MWh	@	0.027203	22	0.022646	18	(4)
9	Mid-peak kWh	893	MWh	@	0.024220	22	0.020163	18	(4)
10	Low-peak kWh	7,257	MWh	@	0.019519	142	0.016250	118	(24)
11	Off-peak kWh	10,112	MWh	@	0.014600	148	0.012154	123	(25)
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	73	MWh	@	0.062854	5	0.075508	6	1
13	High-peak kWh	1,571	MWh	@	0.041903	66	0.050339	79	13
14	Mid-peak kWh	1,737	MWh	@	0.039232	68	0.045094	78	10
15	Off-peak kWh	29,649	MWh	@	0.032990	978	0.037436	1,110	132
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	73	MWh	@	0.026287	2	0.021884	2	(0)
18	High-peak kWh	1,571	MWh	@	0.017525	28	0.014589	23	(5)
19	Mid-peak kWh	1,737	MWh	@	0.016225	28	0.013507	23	(5)
20	Off-peak kWh	29,649	MWh	@	0.013498	400	0.011237	333	(67)
21	Power Factor Adjustment					(14)		(10)	4
22	Interruptible Credit	52,117	MWh	@	(0.008461)	(441)	(0.008502)	(443)	(2)
23	Annual PSCR Factor	52,117	MWh	@	0.013710	715	0.013710	715	-
24	Total Production					$ 2,980		$ 3,117	$ 137
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	34	MWh	@	0.042153	$ 1	0.047616	$ 2	$ 0
26	High-peak kWh	791	MWh	@	0.028102	22	0.031744	25	3
27	Mid-peak kWh	893	MWh	@	0.025021	22	0.028264	25	3
28	Low-peak kWh	7,257	MWh	@	0.020164	146	0.022778	165	19
29	Off-peak kWh	10,112	MWh	@	0.015082	153	0.017037	172	20
	Winter (Oct. - May)								
30	Critical-peak kWh	73	MWh	@	0.027155	2	0.030675	2	0
31	High-peak kWh	1,571	MWh	@	0.018104	28	0.020450	32	4
32	Mid-peak kWh	1,737	MWh	@	0.016761	29	0.018934	33	4
33	Off-peak kWh	29,649	MWh	@	0.013944	413	0.015751	467	54
34	Total Transmission					$ 818		$ 924	$ 106
	Delivery								
35	System Access	72	Bills	@	200.00	$ 14	200.00	$ 14	$ -
36	Maximum kW	379	MW	@	3.61	1,369	4.45	1,689	319
37	Substation Ownership	170	MW	@	(1.93)	(329)	(2.16)	(367)	(38)
38	Power Factor Adjustment					(5)		(5)	1
39	Distribution	52,117	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,050		$ 1,331	$ 281
41	Total Full Service					$ 4,848		$ 5,372	$ 525

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Primary Energy Intensive Level 3 (EIP VL 3)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 20 of 24
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
	Non-capacity								
1	Critical-peak kWh	6	MWh	@	0.101677	$ 1	0.116685	$ 1	$ 0
2	High-peak kWh	82	MWh	@	0.067784	6	0.077790	6	1
3	Mid-peak kWh	119	MWh	@	0.060790	7	0.069354	8	1
4	Low-peak kWh	1,731	MWh	@	0.048314	84	0.055411	96	12
5	Off-peak kWh	909	MWh	@	0.035378	32	0.039916	36	4
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	6	MWh	@	0.041452	0	0.034465	0	(0)
8	High-peak kWh	82	MWh	@	0.027635	2	0.022977	2	(0)
9	Mid-peak kWh	119	MWh	@	0.024605	3	0.020457	2	(0)
10	Low-peak kWh	1,731	MWh	@	0.019829	34	0.016487	29	(6)
11	Off-peak kWh	909	MWh	@	0.014831	13	0.012331	11	(2)
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	4	MWh	@	0.063488	0	0.076262	0	0
13	High-peak kWh	101	MWh	@	0.042325	4	0.050841	5	1
14	Mid-peak kWh	128	MWh	@	0.039628	5	0.045544	6	1
15	Off-peak kWh	4,148	MWh	@	0.033323	138	0.037810	157	19
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	4	MWh	@	0.026704	0	0.022203	0	(0)
18	High-peak kWh	101	MWh	@	0.017803	2	0.014802	1	(0)
19	Mid-peak kWh	128	MWh	@	0.016483	2	0.013704	2	(0)
20	Off-peak kWh	4,148	MWh	@	0.013712	57	0.011401	47	(10)
21	Power Factor Adjustment					(1)		(2)	(1)
22	Interruptible Credit	7,229	MWh	@	(0.008461)	(61)	(0.008502)	(61)	(0)
23	Annual PSCR Factor	7,229	MWh	@	0.013710	99	0.013710	99	-
24	Total Production					$ 428		$ 447	$ 18
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	6	MWh	@	0.042822	$ 0	0.048311	$ 0	$ 0
26	High-peak kWh	82	MWh	@	0.028548	2	0.032207	3	0
27	Mid-peak kWh	119	MWh	@	0.025418	3	0.028676	3	0
28	Low-peak kWh	1,731	MWh	@	0.020484	35	0.023110	40	5
29	Off-peak kWh	909	MWh	@	0.015321	14	0.017285	16	2
	Winter (Oct. - May)								
30	Critical-peak kWh	4	MWh	@	0.027586	0	0.031123	0	0
31	High-peak kWh	101	MWh	@	0.018391	2	0.020748	2	0
32	Mid-peak kWh	128	MWh	@	0.017027	2	0.019210	2	0
33	Off-peak kWh	4,148	MWh	@	0.014165	59	0.015981	66	8
34	Total Transmission					$ 118		$ 133	$ 15
	Delivery								
35	System Access	54	Bills	@	200.00	$ 11	200.00	$ 11	$ -
36	Maximum kW	45	MW	@	6.68	298	8.12	363	64
37	Power Factor Adjustment					(1)		(1)	(1)
38	Distribution	7,229	MWh	@	-	-	-	-	-
39	Total Delivery					$ 309		$ 372	$ 64
40	Total Full Service					$ 855		$ 952	$ 97

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Metered Lighting (GML)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
1	Secondary All kWh	10,022	MWh	@	0.034716	$ 348	0.043284	$ 434	$ 86
2	Primary All kWh	443	MWh	@	0.017037	8	0.021242	9	2
3	Annual PSCR Factor	10,465	MWh	@	0.013710	143	0.013710	143	-
4	Total Production					$ 499		$ 587	$ 88
	Transmission								
5	Secondary All kWh	10,022	MWh	@	0.010556	106	0.011955	120	14
6	Primary All kWh	443	MWh	@	0.005180	2	0.005867	3	0
7	Total Transmission	10,465				108		122	14
	Delivery								
	Secondary								
8	System Access	4,555	Bills	@	10.00	$ 46	10.00	$ 46	$ -
9	Distribution	10,022	MWh	@	0.118564	1,188	0.135414	1,357	169
	Primary								
10	System Access	81	Bills	@	20.00	$ 2	20.00	$ 2	$ -
11	Distribution	443	MWh	@	0.090355	40	0.103197	46	6
12	Total Delivery					$ 1,275		$ 1,450	$ 175
13	Total Full Service					$ 1,882		$ 2,159	$ 277

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Universal Unmetered Light (UUL)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
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Witness: MCGrondin
Date: June 2026

Line		Billing Determinants							Present					Proposed					Net Increase
						Customer	Company		Customer Owned		Company Owned			Customer Owned		Company Owned			
No.	Description	Customer	Company	Units	Watts	MWh	MWh		Production	Delivery	Production	Delivery	Revenue	Production	Delivery	Production	Delivery	Revenue	/ (Decrease)
									$/Light	$/Light	$/Light	$/Light	$000	$/Light	$/Light	$/Light	$/Light	$000	$000
1	15 - 24 Watts	12	-	Lights	20	0	-	@	0.28	7.29	0.28	10.29	$ 0	0.38	8.04	0.38	11.04	$ 0	$ 0
2	25 - 34 Watts	-	370,944	Lights	30	-	3,830	@	0.43	8.07	0.43	11.07	4,266	0.57	8.92	0.57	11.92	4,633	367
3	35 - 44 Watts	1,524	269,199	Lights	40	21	3,722	@	0.57	8.85	0.57	11.85	3,358	0.76	9.81	0.76	12.81	3,669	311
4	45 - 54 Watts	1,308	951,251	Lights	50	23	16,480	@	0.72	9.63	0.72	12.63	12,713	0.96	10.69	0.96	13.69	13,951	1,238
5	55 - 64 Watts	1,092	12,096	Lights	60	23	252	@	0.86	10.41	0.86	13.41	185	1.15	11.58	1.15	14.58	204	19
6	65 - 74 Watts	312	136,158	Lights	70	8	3,312	@	1.01	11.19	1.01	14.19	2,073	1.34	12.46	1.34	15.46	2,292	218
7	75 - 84 Watts	72	50,327	Lights	80	2	1,400	@	1.15	11.97	1.15	14.97	812	1.53	13.35	1.53	16.35	901	89
8	85 - 94 Watts	36	97,092	Lights	90	1	3,041	@	1.29	12.75	1.29	15.75	1,655	1.73	14.23	1.73	17.23	1,841	186
9	95 - 104 Watts	-	-	Lights	100	-	-	@	1.44	13.53	1.44	16.53	-	1.92	15.12	1.92	18.12	-	-
10	105 - 114 Watts	-	5,927	Lights	110	-	227	@	1.58	14.31	1.58	17.31	112	2.11	16.00	2.11	19.00	125	13
11	115 - 124 Watts	804	122,508	Lights	120	34	5,124	@	1.73	15.09	1.73	18.09	2,442	2.31	16.89	2.31	19.89	2,735	293
12	125 - 134 Watts	-	272	Lights	130	-	12	@	1.87	15.86	1.87	18.86	6	2.50	17.77	2.50	20.77	6	1
13	135 - 144 Watts	-	9,542	Lights	140	-	466	@	2.02	16.64	2.02	19.64	207	2.69	18.66	2.69	21.66	232	26
14	145 - 154 Watts	-	3,802	Lights	150	-	199	@	2.16	17.42	2.16	20.42	86	2.88	19.54	2.88	22.54	97	11
15	155 - 164 Watts	-	36	Lights	160	-	2	@	2.31	18.20	2.31	21.20	1	3.08	20.43	3.08	23.43	1	0
16	165 - 174 Watts	1,404	63,964	Lights	170	83	3,795	@	2.45	18.98	2.45	21.98	1,593	3.27	21.31	3.27	24.31	1,799	206
17	175 - 184 Watts	-	-	Lights	180	-	-	@	2.60	19.76	2.60	22.76	-	3.46	22.19	3.46	25.19	-	-
18	185 - 194 Watts	-	-	Lights	190	-	-	@	2.74	20.54	2.74	23.54	-	3.66	23.08	3.66	26.08	-	-
19	195 - 204 Watts	-	100	Lights	200	-	7	@	2.89	21.32	2.89	24.32	3	3.85	23.96	3.85	26.96	3	0
20	205 - 214 Watts	504	11,370	Lights	210	37	834	@	3.03	22.10	3.03	25.10	333	4.04	24.85	4.04	27.85	377	45
21	215 - 224 Watts	-	-	Lights	220	-	-	@	3.17	22.88	3.17	25.88	-	4.24	25.73	4.24	28.73	-	-
22	225 - 234 Watts	-	-	Lights	230	-	-	@	3.32	23.66	3.32	26.66	-	4.43	26.62	4.43	29.62	-	-
23	235 - 244 Watts	-	-	Lights	240	-	-	@	3.46	24.44	3.46	27.44	-	4.62	27.50	4.62	30.50	-	-
24	245 - 254 Watts	60	936	Lights	250	5	82	@	3.61	25.22	3.61	28.22	32	4.81	28.39	4.81	31.39	36	4
25	255 - 264 Watts	-	-	Lights	260	-	-	@	3.75	26.00	3.75	29.00	-	5.01	29.27	5.01	32.27	-	-
26	265 - 274 Watts	-	-	Lights	270	-	-	@	3.90	26.78	3.90	29.78	-	5.20	30.16	5.20	33.16	-	-
27	275 - 284 Watts	396	3,447	Lights	280	39	337	@	4.04	27.56	4.04	30.56	132	5.39	31.04	5.39	34.04	150	19
28	285 - 294 Watts	12	1,038	Lights	290	1	105	@	4.19	28.34	4.19	31.34	37	5.59	31.93	5.59	34.93	43	5
29	295 - 304 Watts	-	-	Lights	300	-	-	@	4.33	29.12	4.33	32.12	-	5.78	32.81	5.78	35.81	-	-
30	305 - 314 Watts	108	-	Lights	310	12	-	@	4.48	29.90	4.48	32.90	4	5.97	33.70	5.97	36.70	4	1
31	315 - 324 Watts	540	43,996	Lights	320	60	4,920	@	4.62	30.68	4.62	33.68	1,704	6.16	34.58	6.16	37.58	1,946	242
32	325 - 334 Watts	-	-	Lights	330	-	-	@	4.77	31.45	4.77	34.45	-	6.36	35.47	6.36	38.47	-	-
33	335 - 344 Watts	-	-	Lights	340	-	-	@	4.91	32.23	4.91	35.23	-	6.55	36.35	6.55	39.35	-	-
34	345 - 354 Watts	-	-	Lights	350	-	-	@	5.05	33.01	5.05	36.01	-	6.74	37.24	6.74	40.24	-	-
35	355 - 364 Watts	-	-	Lights	360	-	-	@	5.20	33.79	5.20	36.79	-	6.94	38.12	6.94	41.12	-	-
36	365 - 374 Watts	-	3,624	Lights	370	-	469	@	5.34	34.57	5.34	37.57	156	7.13	39.01	7.13	42.01	178	23
37	375 - 384 Watts	-	-	Lights	380	-	-	@	5.49	35.35	5.49	38.35	-	7.32	39.89	7.32	42.89	-	-
38	385 - 394 Watts	-	-	Lights	390	-	-	@	5.63	36.13	5.63	39.13	-	7.52	40.78	7.52	43.78	-	-
39	395 - 404 Watts	-	24	Lights	400	-	3	@	5.78	36.91	5.78	39.91	1	7.71	41.66	7.71	44.66	1	0
40	405 - 414 Watts	24	-	Lights	410	3	-	@	5.92	37.69	5.92	40.69	1	7.90	42.55	7.90	45.55	1	0
41	415 - 424 Watts	-	-	Lights	420	-	-	@	6.07	38.47	6.07	41.47	-	8.09	43.43	8.09	46.43	-	-
42	425 - 434 Watts	-	-	Lights	430	-	-	@	6.21	39.25	6.21	42.25	-	8.29	44.32	8.29	47.32	-	-
43	435 - 444 Watts	-	-	Lights	440	-	-	@	6.36	40.03	6.36	43.03	-	8.48	45.20	8.48	48.20	-	-
44	445 - 454 Watts	24	-	Lights	450	4	-	@	6.50	40.81	6.50	43.81	1	8.67	46.09	8.67	49.09	1	0
45	455 - 464 Watts	864	1,250	Lights	460	139	201	@	6.65	41.59	6.65	44.59	106	8.87	46.97	8.87	49.97	122	16
46	465 - 474 Watts	-	-	Lights	470	-	-	@	6.79	42.37	6.79	45.37	-	9.06	47.86	9.06	50.86	-	-
47	475 - 484 Watts	180	33,307	Lights	480	30	5,590	@	6.94	43.15	6.94	46.15	1,777	9.25	48.74	9.25	51.74	2,042	265
48	Conversion Credit	-	129,840	Lights								(7.72)	(1,002)				(7.57)	(983)	19
49	Annual PSCR Factor	9,276	2,192,211	Lights		525	54,410		0.013710		0.013710		753	0.013710		0.013710		753	-
50	Total Unmetered LED	9,276	2,192,211	Lights		525	54,410						$ 33,544					$ 37,162	$ 3,619

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Unmetered Service (GU)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 23 of 24
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
1	Non-capacity All kWh	92,721	MWh	@	0.037706	$ 3,496	0.044686	$ 4,143	$ 647
2	Capacity All kWh	92,721	MWh	@	0.015927	1,477	0.013614	1,262	(214)
3	Annual PSCR Factor	92,721	MWh	@	0.013710	1,271	0.013710	1,271	-
4	Total Production					$ 6,244		$ 6,677	$ 433
	Transmission								
5	All kWh	92,721	MWh	@	0.015085	1,399	0.017146	1,590	191
	Delivery								
6	System Access	5,525	Bills	@	2.00	$ 11	2.00	$ 11	$ -
7	Distribution	92,721	MWh	@	0.034452	3,194	0.040553	3,760	566
8	Total Delivery					$ 3,205		$ 3,771	$ 566
9	Total Full Service					$ 10,848		$ 12,038	$ 1,189

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Large Self-generation (GSG-2)

Case No.: U-22070
Exhibit No.: A-16 (MCG-3)
Schedule: F-3.0
Page: 24 of 24
Witness: MCGrondin
Date: June 2026

Line No.	Description	Billing Determinants Quantity	Units		Present Rate $/unit	Present Revenue $000	Proposed Rate $/unit	Proposed Revenue $000	Net Increase / (Decrease) $000
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)
	STANDBY SERVICE								
	Production								
	Voltage Level 1								
1	On-peak kW-day	73	MW	@	11.27	$ 825	11.27	$ 825	$ -
2	All kWh	57,084	MWh	@	0.042231	2,411	0.042231	2,411	-
	Voltage Level 2								
3	On-peak kW-day	272	MW	@	11.43	3,108	11.43	3,108	-
4	All kWh	81,548	MWh	@	0.042699	3,482	0.042699	3,482	-
	Voltage Level 3								
5	On-peak kW-day	54	MW	@	11.59	627	11.59	627	-
6	All kWh	14,562	MWh	@	0.043093	628	0.043093	628	-
7	Power Factor Adjustment					226		226	-
8	Total Production					$ 11,305		$ 11,305	$ -
	Transmission								
	Voltage Level 1								
9	On-peak kW-day	73	MW	@	3.31	$ 242	3.31	$ 242	$ -
	Voltage Level 2								
10	On-peak kW-day	272	MW	@	3.36	914	3.36	914	-
	Voltage Level 3								
11	On-peak kW-day	54	MW	@	3.41	184	3.41	184	-
12	Total Transmission					$ 1,340		$ 1,340	$ -
	Delivery								
	System Access								
	Voltage Level 1								
13	Standby	49	Bills	@	100.00	$ 5	100.00	$ 5	$ -
14	Supplemental	-	Bills	@	100.00	-	100.00	-	-
15	Maximum kW	404	MW	@	2.37	958	3.28	1,323	365
16	Interconnect	355	MW	@	(2.37)	(842)	(3.28)	(1,163)	(321)
17	Substation Ownership	-	MW	@	(1.82)	-	(2.51)	-	-
	Voltage Level 2								
18	Standby	91	Bills	@	100.00	$ 9	100.00	$ 9	$ -
19	Supplemental	-	Bills	@	100.00	-	100.00	-	-
20	Maximum kW	598	MW	@	3.61	2,161	4.45	2,665	504
21	Substation Ownership	253	MW	@	(1.93)	(489)	(2.16)	(545)	(57)
	Voltage Level 3								
22	Standby	33	Bills	@	100.00	$ 3	100.00	$ 3	$ -
23	Supplemental	-	Bills	@	100.00	-	100.00	-	-
24	Maximum kW	61	MW	@	6.68	405	8.12	492	87
25	Power Factor Adjustment					48		19	(29)
26	Total Delivery					$ 2,258		$ 2,808	$ 550
27	Total Standby Service					$ 14,904		$ 15,454	$ 550

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Summer On-peak RSP

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 1 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	9.05	9.16	0.11	1.2%	183.2	8.90	9.00	0.10	1.1%	180.0
2	50	18.51	19.59	1.08	5.8%	39.2	17.01	18.01	1.00	5.9%	36.0
3	100	29.03	31.18	2.16	7.4%	31.2	26.03	28.03	2.00	7.7%	28.0
4	150	39.54	42.77	3.23	8.2%	28.5	35.04	38.04	3.00	8.6%	25.4
5	200	50.05	54.36	4.31	8.6%	27.2	44.05	48.05	4.00	9.1%	24.0
6	250	60.56	65.95	5.39	8.9%	26.4	53.06	58.06	5.00	9.4%	23.2
7	300	71.08	77.54	6.47	9.1%	25.8	62.08	68.08	6.00	9.7%	22.7
8	350	81.59	89.13	7.54	9.2%	25.5	71.09	78.09	7.00	9.8%	22.3
9	400	92.10	100.72	8.62	9.4%	25.2	80.10	88.10	8.00	10.0%	22.0
10	450	102.61	112.31	9.70	9.5%	25.0	89.11	98.12	9.00	10.1%	21.8
11	500	113.13	123.90	10.78	9.5%	24.8	98.13	108.13	10.00	10.2%	21.6
12	550	123.64	135.49	11.86	9.6%	24.6	107.14	118.14	11.00	10.3%	21.5
13	600	134.15	147.08	12.93	9.6%	24.5	116.15	128.15	12.00	10.3%	21.4
14	650	144.66	158.67	14.01	9.7%	24.4	125.17	138.17	13.00	10.4%	21.3
15	700	155.18	170.27	15.09	9.7%	24.3	134.18	148.18	14.00	10.4%	21.2
16	750	165.69	181.86	16.17	9.8%	24.2	143.19	158.19	15.00	10.5%	21.1
17	800	176.20	193.45	17.24	9.8%	24.2	152.20	168.21	16.00	10.5%	21.0
18	850	186.71	205.04	18.32	9.8%	24.1	161.22	178.22	17.00	10.5%	21.0
19	900	197.23	216.63	19.40	9.8%	24.1	170.23	188.23	18.00	10.6%	20.9
20	950	207.74	228.22	20.48	9.9%	24.0	179.24	198.24	19.00	10.6%	20.9
21	1,000	218.25	239.81	21.56	9.9%	24.0	188.26	208.26	20.00	10.6%	20.8
22	1,500	323.38	355.71	32.33	10.0%	23.7	278.38	308.39	30.00	10.8%	20.6
23	2,000	428.50	471.62	43.11	10.1%	23.6	368.51	408.51	40.00	10.9%	20.4
24	2,500	533.63	587.52	53.89	10.1%	23.5	458.64	508.64	50.00	10.9%	20.3
25	3,000	638.76	703.42	64.67	10.1%	23.4	548.77	608.77	60.01	10.9%	20.3
26	3,500	743.88	819.33	75.45	10.1%	23.4	638.89	708.90	70.01	11.0%	20.3
27	4,000	849.01	935.23	86.22	10.2%	23.4	729.02	809.03	80.01	11.0%	20.2
28	4,500	954.13	1,051.13	97.00	10.2%	23.4	819.15	909.16	90.01	11.0%	20.2
29	5,000	1,059.26	1,167.04	107.78	10.2%	23.3	909.28	1,009.29	100.01	11.0%	20.2

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Summer On-peak RSP
Senior Citizen Provision RSC

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 2 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	5.05	5.16	0.11	2.1%	103.2	4.90	5.00	0.10	2.0%	100.0
2	50	14.51	15.59	1.08	7.4%	31.2	13.01	14.01	1.00	7.7%	28.0
3	100	25.03	27.18	2.16	8.6%	27.2	22.03	24.03	2.00	9.1%	24.0
4	150	35.54	38.77	3.23	9.1%	25.8	31.04	34.04	3.00	9.7%	22.7
5	200	46.05	50.36	4.31	9.4%	25.2	40.05	44.05	4.00	10.0%	22.0
6	250	56.56	61.95	5.39	9.5%	24.8	49.06	54.06	5.00	10.2%	21.6
7	300	67.08	73.54	6.47	9.6%	24.5	58.08	64.08	6.00	10.3%	21.4
8	350	77.59	85.13	7.54	9.7%	24.3	67.09	74.09	7.00	10.4%	21.2
9	400	88.10	96.72	8.62	9.8%	24.2	76.10	84.10	8.00	10.5%	21.0
10	450	98.61	108.31	9.70	9.8%	24.1	85.11	94.12	9.00	10.6%	20.9
11	500	109.13	119.90	10.78	9.9%	24.0	94.13	104.13	10.00	10.6%	20.8
12	550	119.64	131.49	11.86	9.9%	23.9	103.14	114.14	11.00	10.7%	20.8
13	600	130.15	143.08	12.93	9.9%	23.8	112.15	124.15	12.00	10.7%	20.7
14	650	140.66	154.67	14.01	10.0%	23.8	121.17	134.17	13.00	10.7%	20.6
15	700	151.18	166.27	15.09	10.0%	23.8	130.18	144.18	14.00	10.8%	20.6
16	750	161.69	177.86	16.17	10.0%	23.7	139.19	154.19	15.00	10.8%	20.6
17	800	172.20	189.45	17.24	10.0%	23.7	148.20	164.21	16.00	10.8%	20.5
18	850	182.71	201.04	18.32	10.0%	23.7	157.22	174.22	17.00	10.8%	20.5
19	900	193.23	212.63	19.40	10.0%	23.6	166.23	184.23	18.00	10.8%	20.5
20	950	203.74	224.22	20.48	10.1%	23.6	175.24	194.24	19.00	10.8%	20.4
21	1,000	214.25	235.81	21.56	10.1%	23.6	184.26	204.26	20.00	10.9%	20.4
22	1,500	319.38	351.71	32.33	10.1%	23.4	274.38	304.39	30.00	10.9%	20.3
23	2,000	424.50	467.62	43.11	10.2%	23.4	364.51	404.51	40.00	11.0%	20.2
24	2,500	529.63	583.52	53.89	10.2%	23.3	454.64	504.64	50.00	11.0%	20.2
25	3,000	634.76	699.42	64.67	10.2%	23.3	544.77	604.77	60.01	11.0%	20.2
26	3,500	739.88	815.33	75.45	10.2%	23.3	634.89	704.90	70.01	11.0%	20.1
27	4,000	845.01	931.23	86.22	10.2%	23.3	725.02	805.03	80.01	11.0%	20.1
28	4,500	950.13	1,047.13	97.00	10.2%	23.3	815.15	905.16	90.01	11.0%	20.1
29	5,000	1,055.26	1,163.04	107.78	10.2%	23.3	905.28	1,005.29	100.01	11.0%	20.1

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Summer On-peak RSP
Income Assistance Provision RIA

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 3 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	1.05	(2.84)	(3.89)	-370.2%	(56.8)	0.90	(3.00)	(3.90)	-432.7%	(60.0)
2	50	10.51	7.59	(2.92)	-27.8%	15.2	9.01	6.01	(3.00)	-33.3%	12.0
3	100	21.03	19.18	(1.84)	-8.8%	19.2	18.03	16.03	(2.00)	-11.1%	16.0
4	150	31.54	30.77	(0.77)	-2.4%	20.5	27.04	26.04	(1.00)	-3.7%	17.4
5	200	42.05	42.36	0.31	0.7%	21.2	36.05	36.05	0.00	0.0%	18.0
6	250	52.56	53.95	1.39	2.6%	21.6	45.06	46.06	1.00	2.2%	18.4
7	300	63.08	65.54	2.47	3.9%	21.8	54.08	56.08	2.00	3.7%	18.7
8	350	73.59	77.13	3.54	4.8%	22.0	63.09	66.09	3.00	4.8%	18.9
9	400	84.10	88.72	4.62	5.5%	22.2	72.10	76.10	4.00	5.5%	19.0
10	450	94.61	100.31	5.70	6.0%	22.3	81.11	86.12	5.00	6.2%	19.1
11	500	105.13	111.90	6.78	6.4%	22.4	90.13	96.13	6.00	6.7%	19.2
12	550	115.64	123.49	7.86	6.8%	22.5	99.14	106.14	7.00	7.1%	19.3
13	600	126.15	135.08	8.93	7.1%	22.5	108.15	116.15	8.00	7.4%	19.4
14	650	136.66	146.67	10.01	7.3%	22.6	117.17	126.17	9.00	7.7%	19.4
15	700	147.18	158.27	11.09	7.5%	22.6	126.18	136.18	10.00	7.9%	19.5
16	750	157.69	169.86	12.17	7.7%	22.6	135.19	146.19	11.00	8.1%	19.5
17	800	168.20	181.45	13.24	7.9%	22.7	144.20	156.21	12.00	8.3%	19.5
18	850	178.71	193.04	14.32	8.0%	22.7	153.22	166.22	13.00	8.5%	19.6
19	900	189.23	204.63	15.40	8.1%	22.7	162.23	176.23	14.00	8.6%	19.6
20	950	199.74	216.22	16.48	8.2%	22.8	171.24	186.24	15.00	8.8%	19.6
21	1,000	210.25	227.81	17.56	8.3%	22.8	180.26	196.26	16.00	8.9%	19.6
22	1,500	315.38	343.71	28.33	9.0%	22.9	270.38	296.39	26.00	9.6%	19.8
23	2,000	420.50	459.62	39.11	9.3%	23.0	360.51	396.51	36.00	10.0%	19.8
24	2,500	525.63	575.52	49.89	9.5%	23.0	450.64	496.64	46.00	10.2%	19.9
25	3,000	630.76	691.42	60.67	9.6%	23.0	540.77	596.77	56.01	10.4%	19.9
26	3,500	735.88	807.33	71.45	9.7%	23.1	630.89	696.90	66.01	10.5%	19.9
27	4,000	841.01	923.23	82.22	9.8%	23.1	721.02	797.03	76.01	10.5%	19.9
28	4,500	946.13	1,039.13	93.00	9.8%	23.1	811.15	897.16	86.01	10.6%	19.9
29	5,000	1,051.26	1,155.04	103.78	9.9%	23.1	901.28	997.29	96.01	10.7%	19.9

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Smart Hours RSH

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	9.05	9.16	0.11	1.2%	183.1	8.90	9.00	0.10	1.1%	180.0
2	50	18.50	19.57	1.08	5.8%	39.1	17.01	18.01	1.00	5.9%	36.0
3	100	28.99	31.15	2.15	7.4%	31.1	26.02	28.02	2.00	7.7%	28.0
4	150	39.49	42.72	3.23	8.2%	28.5	35.03	38.03	3.00	8.6%	25.4
5	200	49.99	54.29	4.31	8.6%	27.1	44.04	48.03	4.00	9.1%	24.0
6	250	60.48	65.87	5.38	8.9%	26.3	53.04	58.04	5.00	9.4%	23.2
7	300	70.98	77.44	6.46	9.1%	25.8	62.05	68.05	6.00	9.7%	22.7
8	350	81.48	89.01	7.54	9.2%	25.4	71.06	78.06	7.00	9.8%	22.3
9	400	91.97	100.59	8.61	9.4%	25.1	80.07	88.07	8.00	10.0%	22.0
10	450	102.47	112.16	9.69	9.5%	24.9	89.08	98.08	9.00	10.1%	21.8
11	500	112.97	123.73	10.76	9.5%	24.7	98.09	108.08	10.00	10.2%	21.6
12	550	123.46	135.31	11.84	9.6%	24.6	107.10	118.09	11.00	10.3%	21.5
13	600	133.96	146.88	12.92	9.6%	24.5	116.11	128.10	12.00	10.3%	21.4
14	650	144.46	158.45	13.99	9.7%	24.4	125.11	138.11	13.00	10.4%	21.2
15	700	154.95	170.02	15.07	9.7%	24.3	134.12	148.12	14.00	10.4%	21.2
16	750	165.45	181.60	16.15	9.8%	24.2	143.13	158.13	14.99	10.5%	21.1
17	800	175.95	193.17	17.22	9.8%	24.1	152.14	168.13	15.99	10.5%	21.0
18	850	186.44	204.74	18.30	9.8%	24.1	161.15	178.14	16.99	10.5%	21.0
19	900	196.94	216.32	19.38	9.8%	24.0	170.16	188.15	17.99	10.6%	20.9
20	950	207.44	227.89	20.45	9.9%	24.0	179.17	198.16	18.99	10.6%	20.9
21	1,000	217.93	239.46	21.53	9.9%	23.9	188.18	208.17	19.99	10.6%	20.8
22	1,500	322.90	355.20	32.29	10.0%	23.7	278.26	308.25	29.99	10.8%	20.6
23	2,000	427.87	470.93	43.06	10.1%	23.5	368.35	408.34	39.99	10.9%	20.4
24	2,500	532.84	586.66	53.82	10.1%	23.5	458.44	508.42	49.98	10.9%	20.3
25	3,000	637.80	702.39	64.59	10.1%	23.4	548.53	608.51	59.98	10.9%	20.3
26	3,500	742.77	818.12	75.35	10.1%	23.4	638.61	708.59	69.98	11.0%	20.2
27	4,000	847.74	933.86	86.12	10.2%	23.3	728.70	808.67	79.97	11.0%	20.2
28	4,500	952.71	1,049.59	96.88	10.2%	23.3	818.79	908.76	89.97	11.0%	20.2
29	5,000	1,057.67	1,165.32	107.65	10.2%	23.3	908.88	1,008.84	99.96	11.0%	20.2

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Smart Hours RSH
Senior Citizen Provision RSC

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	5.05	5.16	0.11	2.1%	103.1	4.90	5.00	0.10	2.0%	100.0
2	50	14.50	15.57	1.08	7.4%	31.1	13.01	14.01	1.00	7.7%	28.0
3	100	24.99	27.15	2.15	8.6%	27.1	22.02	24.02	2.00	9.1%	24.0
4	150	35.49	38.72	3.23	9.1%	25.8	31.03	34.03	3.00	9.7%	22.7
5	200	45.99	50.29	4.31	9.4%	25.1	40.04	44.03	4.00	10.0%	22.0
6	250	56.48	61.87	5.38	9.5%	24.7	49.04	54.04	5.00	10.2%	21.6
7	300	66.98	73.44	6.46	9.6%	24.5	58.05	64.05	6.00	10.3%	21.4
8	350	77.48	85.01	7.54	9.7%	24.3	67.06	74.06	7.00	10.4%	21.2
9	400	87.97	96.59	8.61	9.8%	24.1	76.07	84.07	8.00	10.5%	21.0
10	450	98.47	108.16	9.69	9.8%	24.0	85.08	94.08	9.00	10.6%	20.9
11	500	108.97	119.73	10.76	9.9%	23.9	94.09	104.08	10.00	10.6%	20.8
12	550	119.46	131.31	11.84	9.9%	23.9	103.10	114.09	11.00	10.7%	20.7
13	600	129.96	142.88	12.92	9.9%	23.8	112.11	124.10	12.00	10.7%	20.7
14	650	140.46	154.45	13.99	10.0%	23.8	121.11	134.11	13.00	10.7%	20.6
15	700	150.95	166.02	15.07	10.0%	23.7	130.12	144.12	14.00	10.8%	20.6
16	750	161.45	177.60	16.15	10.0%	23.7	139.13	154.13	14.99	10.8%	20.6
17	800	171.95	189.17	17.22	10.0%	23.6	148.14	164.13	15.99	10.8%	20.5
18	850	182.44	200.74	18.30	10.0%	23.6	157.15	174.14	16.99	10.8%	20.5
19	900	192.94	212.32	19.38	10.0%	23.6	166.16	184.15	17.99	10.8%	20.5
20	950	203.44	223.89	20.45	10.1%	23.6	175.17	194.16	18.99	10.8%	20.4
21	1,000	213.93	235.46	21.53	10.1%	23.5	184.18	204.17	19.99	10.9%	20.4
22	1,500	318.90	351.20	32.29	10.1%	23.4	274.26	304.25	29.99	10.9%	20.3
23	2,000	423.87	466.93	43.06	10.2%	23.3	364.35	404.34	39.99	11.0%	20.2
24	2,500	528.84	582.66	53.82	10.2%	23.3	454.44	504.42	49.98	11.0%	20.2
25	3,000	633.80	698.39	64.59	10.2%	23.3	544.53	604.51	59.98	11.0%	20.2
26	3,500	738.77	814.12	75.35	10.2%	23.3	634.61	704.59	69.98	11.0%	20.1
27	4,000	843.74	929.86	86.12	10.2%	23.2	724.70	804.67	79.97	11.0%	20.1
28	4,500	948.71	1,045.59	96.88	10.2%	23.2	814.79	904.76	89.97	11.0%	20.1
29	5,000	1,053.67	1,161.32	107.65	10.2%	23.2	904.88	1,004.84	99.96	11.0%	20.1

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Smart Hours RSH
Income Assistance Provision RIA

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	1.05	(2.84)	(3.89)	-370.8%	(56.9)	0.90	(3.00)	(3.90)	-432.9%	(60.0)
2	50	10.50	7.57	(2.92)	-27.9%	15.1	9.01	6.01	(3.00)	-33.3%	12.0
3	100	20.99	19.15	(1.85)	-8.8%	19.1	18.02	16.02	(2.00)	-11.1%	16.0
4	150	31.49	30.72	(0.77)	-2.4%	20.5	27.03	26.03	(1.00)	-3.7%	17.4
5	200	41.99	42.29	0.31	0.7%	21.1	36.04	36.03	(0.00)	0.0%	18.0
6	250	52.48	53.87	1.38	2.6%	21.5	45.04	46.04	1.00	2.2%	18.4
7	300	62.98	65.44	2.46	3.9%	21.8	54.05	56.05	2.00	3.7%	18.7
8	350	73.48	77.01	3.54	4.8%	22.0	63.06	66.06	3.00	4.8%	18.9
9	400	83.97	88.59	4.61	5.5%	22.1	72.07	76.07	4.00	5.5%	19.0
10	450	94.47	100.16	5.69	6.0%	22.3	81.08	86.08	5.00	6.2%	19.1
11	500	104.97	111.73	6.76	6.4%	22.3	90.09	96.08	6.00	6.7%	19.2
12	550	115.46	123.31	7.84	6.8%	22.4	99.10	106.09	7.00	7.1%	19.3
13	600	125.96	134.88	8.92	7.1%	22.5	108.11	116.10	8.00	7.4%	19.4
14	650	136.46	146.45	9.99	7.3%	22.5	117.11	126.11	9.00	7.7%	19.4
15	700	146.95	158.02	11.07	7.5%	22.6	126.12	136.12	10.00	7.9%	19.4
16	750	157.45	169.60	12.15	7.7%	22.6	135.13	146.13	10.99	8.1%	19.5
17	800	167.95	181.17	13.22	7.9%	22.6	144.14	156.13	11.99	8.3%	19.5
18	850	178.44	192.74	14.30	8.0%	22.7	153.15	166.14	12.99	8.5%	19.5
19	900	188.94	204.32	15.38	8.1%	22.7	162.16	176.15	13.99	8.6%	19.6
20	950	199.44	215.89	16.45	8.2%	22.7	171.17	186.16	14.99	8.8%	19.6
21	1,000	209.93	227.46	17.53	8.4%	22.7	180.18	196.17	15.99	8.9%	19.6
22	1,500	314.90	343.20	28.29	9.0%	22.9	270.26	296.25	25.99	9.6%	19.8
23	2,000	419.87	458.93	39.06	9.3%	22.9	360.35	396.34	35.99	10.0%	19.8
24	2,500	524.84	574.66	49.82	9.5%	23.0	450.44	496.42	45.98	10.2%	19.9
25	3,000	629.80	690.39	60.59	9.6%	23.0	540.53	596.51	55.98	10.4%	19.9
26	3,500	734.77	806.12	71.35	9.7%	23.0	630.61	696.59	65.98	10.5%	19.9
27	4,000	839.74	921.86	82.12	9.8%	23.0	720.70	796.67	75.97	10.5%	19.9
28	4,500	944.71	1,037.59	92.88	9.8%	23.1	810.79	896.76	85.97	10.6%	19.9
29	5,000	1,049.67	1,153.32	103.65	9.9%	23.1	900.88	996.84	95.96	10.7%	19.9

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Nighttime Savers RPM

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	9.04	9.15	0.11	1.2%	182.9	8.89	8.99	0.10	1.1%	179.9
2	50	18.39	19.46	1.07	5.8%	38.9	16.94	17.93	0.99	5.9%	35.9
3	100	28.78	30.92	2.14	7.4%	30.9	25.88	27.86	1.99	7.7%	27.9
4	150	39.17	42.39	3.21	8.2%	28.3	34.82	37.79	2.98	8.6%	25.2
5	200	49.57	53.85	4.28	8.6%	26.9	43.75	47.73	3.97	9.1%	23.9
6	250	59.96	65.31	5.35	8.9%	26.1	52.69	57.66	4.97	9.4%	23.1
7	300	70.35	76.77	6.42	9.1%	25.6	61.63	67.59	5.96	9.7%	22.5
8	350	80.74	88.23	7.50	9.3%	25.2	70.57	77.52	6.95	9.9%	22.1
9	400	91.13	99.70	8.57	9.4%	24.9	79.51	87.45	7.95	10.0%	21.9
10	450	101.52	111.16	9.64	9.5%	24.7	88.45	97.38	8.94	10.1%	21.6
11	500	111.91	122.62	10.71	9.6%	24.5	97.38	107.32	9.93	10.2%	21.5
12	550	122.30	134.08	11.78	9.6%	24.4	106.32	117.25	10.93	10.3%	21.3
13	600	132.70	145.55	12.85	9.7%	24.3	115.26	127.18	11.92	10.3%	21.2
14	650	143.09	157.01	13.92	9.7%	24.2	124.20	137.11	12.91	10.4%	21.1
15	700	153.48	168.47	14.99	9.8%	24.1	133.14	147.04	13.90	10.4%	21.0
16	750	163.87	179.93	16.06	9.8%	24.0	142.08	156.97	14.90	10.5%	20.9
17	800	174.26	191.39	17.13	9.8%	23.9	151.01	166.91	15.89	10.5%	20.9
18	850	184.65	202.86	18.20	9.9%	23.9	159.95	176.84	16.88	10.6%	20.8
19	900	195.04	214.32	19.27	9.9%	23.8	168.89	186.77	17.88	10.6%	20.8
20	950	205.43	225.78	20.35	9.9%	23.8	177.83	196.70	18.87	10.6%	20.7
21	1,000	215.83	237.24	21.42	9.9%	23.7	186.77	206.63	19.86	10.6%	20.7
22	1,500	319.74	351.86	32.12	10.0%	23.5	276.15	305.95	29.80	10.8%	20.4
23	2,000	423.65	466.49	42.83	10.1%	23.3	365.54	405.26	39.73	10.9%	20.3
24	2,500	527.57	581.11	53.54	10.1%	23.2	454.92	504.58	49.66	10.9%	20.2
25	3,000	631.48	695.73	64.25	10.2%	23.2	544.30	603.90	59.59	10.9%	20.1
26	3,500	735.39	810.35	74.96	10.2%	23.2	633.69	703.21	69.52	11.0%	20.1
27	4,000	839.30	924.97	85.67	10.2%	23.1	723.07	802.53	79.46	11.0%	20.1
28	4,500	943.22	1,039.59	96.37	10.2%	23.1	812.46	901.84	89.39	11.0%	20.0
29	5,000	1,047.13	1,154.21	107.08	10.2%	23.1	901.84	1,001.16	99.32	11.0%	20.0

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Nighttime Savers RPM
Senior Citizen Provision RSC

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 8 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	5.04	5.14	0.10	2.0%	102.8	4.89	4.99	0.10	2.0%	99.9
2	50	14.39	15.41	1.02	7.1%	30.8	12.94	13.93	0.99	7.7%	27.9
3	100	24.78	26.81	2.03	8.2%	26.8	21.88	23.86	1.99	9.1%	23.9
4	150	35.17	38.22	3.05	8.7%	25.5	30.82	33.79	2.98	9.7%	22.5
5	200	45.57	49.63	4.06	8.9%	24.8	39.75	43.73	3.97	10.0%	21.9
6	250	55.96	61.03	5.08	9.1%	24.4	48.69	53.66	4.97	10.2%	21.5
7	300	66.35	72.44	6.09	9.2%	24.1	57.63	63.59	5.96	10.3%	21.2
8	350	76.74	83.84	7.11	9.3%	24.0	66.57	73.52	6.95	10.4%	21.0
9	400	87.13	95.25	8.12	9.3%	23.8	75.51	83.45	7.95	10.5%	20.9
10	450	97.52	106.66	9.14	9.4%	23.7	84.45	93.38	8.94	10.6%	20.8
11	500	107.91	118.06	10.15	9.4%	23.6	93.38	103.32	9.93	10.6%	20.7
12	550	118.30	129.47	11.17	9.4%	23.5	102.32	113.25	10.93	10.7%	20.6
13	600	128.70	140.88	12.18	9.5%	23.5	111.26	123.18	11.92	10.7%	20.5
14	650	139.09	152.28	13.20	9.5%	23.4	120.20	133.11	12.91	10.7%	20.5
15	700	149.48	163.69	14.21	9.5%	23.4	129.14	143.04	13.90	10.8%	20.4
16	750	159.87	175.10	15.23	9.5%	23.3	138.08	152.97	14.90	10.8%	20.4
17	800	170.26	186.50	16.24	9.5%	23.3	147.01	162.91	15.89	10.8%	20.4
18	850	180.65	197.91	17.26	9.6%	23.3	155.95	172.84	16.88	10.8%	20.3
19	900	191.04	209.32	18.27	9.6%	23.3	164.89	182.77	17.88	10.8%	20.3
20	950	201.43	220.72	19.29	9.6%	23.2	173.83	192.70	18.87	10.9%	20.3
21	1,000	211.83	232.13	20.30	9.6%	23.2	182.77	202.63	19.86	10.9%	20.3
22	1,500	315.74	346.19	30.45	9.6%	23.1	272.15	301.95	29.80	10.9%	20.1
23	2,000	419.65	460.26	40.60	9.7%	23.0	361.54	401.26	39.73	11.0%	20.1
24	2,500	523.57	574.32	50.76	9.7%	23.0	450.92	500.58	49.66	11.0%	20.0
25	3,000	627.48	688.39	60.91	9.7%	22.9	540.30	599.90	59.59	11.0%	20.0
26	3,500	731.39	802.45	71.06	9.7%	22.9	629.69	699.21	69.52	11.0%	20.0
27	4,000	835.30	916.51	81.21	9.7%	22.9	719.07	798.53	79.46	11.0%	20.0
28	4,500	939.22	1,030.58	91.36	9.7%	22.9	808.46	897.84	89.39	11.1%	20.0
29	5,000	1,043.13	1,144.64	101.51	9.7%	22.9	897.84	997.16	99.32	11.1%	19.9

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Nighttime Savers RPM
Income Assistance Provision RIA

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 9 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	1.04	(2.85)	(3.89)	-374.6%	(57.1)	0.89	(3.01)	(3.90)	-436.4%	(60.1)
2	50	10.39	7.46	(2.93)	-28.2%	14.9	8.94	5.93	(3.01)	-33.6%	11.9
3	100	20.78	18.92	(1.86)	-8.9%	18.9	17.88	15.86	(2.01)	-11.3%	15.9
4	150	31.17	30.39	(0.79)	-2.5%	20.3	26.82	25.79	(1.02)	-3.8%	17.2
5	200	41.57	41.85	0.28	0.7%	20.9	35.75	35.73	(0.03)	-0.1%	17.9
6	250	51.96	53.31	1.35	2.6%	21.3	44.69	45.66	0.97	2.2%	18.3
7	300	62.35	64.77	2.42	3.9%	21.6	53.63	55.59	1.96	3.7%	18.5
8	350	72.74	76.23	3.50	4.8%	21.8	62.57	65.52	2.95	4.7%	18.7
9	400	83.13	87.70	4.57	5.5%	21.9	71.51	75.45	3.95	5.5%	18.9
10	450	93.52	99.16	5.64	6.0%	22.0	80.45	85.38	4.94	6.1%	19.0
11	500	103.91	110.62	6.71	6.5%	22.1	89.38	95.32	5.93	6.6%	19.1
12	550	114.30	122.08	7.78	6.8%	22.2	98.32	105.25	6.93	7.0%	19.1
13	600	124.70	133.55	8.85	7.1%	22.3	107.26	115.18	7.92	7.4%	19.2
14	650	135.09	145.01	9.92	7.3%	22.3	116.20	125.11	8.91	7.7%	19.2
15	700	145.48	156.47	10.99	7.6%	22.4	125.14	135.04	9.90	7.9%	19.3
16	750	155.87	167.93	12.06	7.7%	22.4	134.08	144.97	10.90	8.1%	19.3
17	800	166.26	179.39	13.13	7.9%	22.4	143.01	154.91	11.89	8.3%	19.4
18	850	176.65	190.86	14.20	8.0%	22.5	151.95	164.84	12.88	8.5%	19.4
19	900	187.04	202.32	15.27	8.2%	22.5	160.89	174.77	13.88	8.6%	19.4
20	950	197.43	213.78	16.35	8.3%	22.5	169.83	184.70	14.87	8.8%	19.4
21	1,000	207.83	225.24	17.42	8.4%	22.5	178.77	194.63	15.86	8.9%	19.5
22	1,500	311.74	339.86	28.12	9.0%	22.7	268.15	293.95	25.80	9.6%	19.6
23	2,000	415.65	454.49	38.83	9.3%	22.7	357.54	393.26	35.73	10.0%	19.7
24	2,500	519.57	569.11	49.54	9.5%	22.8	446.92	492.58	45.66	10.2%	19.7
25	3,000	623.48	683.73	60.25	9.7%	22.8	536.30	591.90	55.59	10.4%	19.7
26	3,500	727.39	798.35	70.96	9.8%	22.8	625.69	691.21	65.52	10.5%	19.7
27	4,000	831.30	912.97	81.67	9.8%	22.8	715.07	790.53	75.46	10.6%	19.8
28	4,500	935.22	1,027.59	92.37	9.9%	22.8	804.46	889.84	85.39	10.6%	19.8
29	5,000	1,039.13	1,142.21	103.08	9.9%	22.8	893.84	989.16	95.32	10.7%	19.8

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Non-Transmitting Meters RSM

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 10 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	8.90	8.99	0.09	1.0%	179.8	8.90	8.99	0.09	1.0%	179.8
2	50	17.01	17.90	0.89	5.2%	35.8	17.01	17.90	0.89	5.2%	35.8
3	100	26.03	27.80	1.77	6.8%	27.8	26.03	27.80	1.77	6.8%	27.8
4	150	35.04	37.70	2.66	7.6%	25.1	35.04	37.70	2.66	7.6%	25.1
5	200	44.05	47.59	3.54	8.0%	23.8	44.05	47.59	3.54	8.0%	23.8
6	250	53.06	57.49	4.43	8.3%	23.0	53.06	57.49	4.43	8.3%	23.0
7	300	62.08	67.39	5.32	8.6%	22.5	62.08	67.39	5.32	8.6%	22.5
8	350	71.09	77.29	6.20	8.7%	22.1	71.09	77.29	6.20	8.7%	22.1
9	400	80.10	87.19	7.09	8.8%	21.8	80.10	87.19	7.09	8.8%	21.8
10	450	89.11	97.09	7.97	8.9%	21.6	89.11	97.09	7.97	8.9%	21.6
11	500	98.13	106.99	8.86	9.0%	21.4	98.13	106.99	8.86	9.0%	21.4
12	550	107.14	116.89	9.75	9.1%	21.3	107.14	116.89	9.75	9.1%	21.3
13	600	116.15	126.78	10.63	9.2%	21.1	116.15	126.78	10.63	9.2%	21.1
14	650	128.61	140.37	11.76	9.1%	21.6	125.17	136.68	11.52	9.2%	21.0
15	700	141.07	153.95	12.88	9.1%	22.0	134.18	146.58	12.40	9.2%	20.9
16	750	153.53	167.53	14.00	9.1%	22.3	143.19	156.48	13.29	9.3%	20.9
17	800	165.99	181.11	15.13	9.1%	22.6	152.20	166.38	14.18	9.3%	20.8
18	850	178.44	194.70	16.25	9.1%	22.9	161.22	176.28	15.06	9.3%	20.7
19	900	190.90	208.28	17.38	9.1%	23.1	170.23	186.18	15.95	9.4%	20.7
20	950	203.36	221.86	18.50	9.1%	23.4	179.24	196.08	16.83	9.4%	20.6
21	1,000	215.82	235.44	19.63	9.1%	23.5	188.26	205.97	17.72	9.4%	20.6
22	1,500	340.40	371.27	30.87	9.1%	24.8	278.38	304.96	26.58	9.5%	20.3
23	2,000	464.98	507.10	42.11	9.1%	25.4	368.51	403.95	35.44	9.6%	20.2
24	2,500	589.56	642.92	53.36	9.1%	25.7	458.64	502.94	44.30	9.7%	20.1
25	3,000	714.15	778.75	64.60	9.0%	26.0	548.77	601.92	53.16	9.7%	20.1
26	3,500	838.73	914.57	75.85	9.0%	26.1	638.89	700.91	62.02	9.7%	20.0
27	4,000	963.31	1,050.40	87.09	9.0%	26.3	729.02	799.90	70.88	9.7%	20.0
28	4,500	1,087.89	1,186.22	98.33	9.0%	26.4	819.15	898.88	79.74	9.7%	20.0
29	5,000	1,212.47	1,322.05	109.58	9.0%	26.4	909.28	997.87	88.59	9.7%	20.0

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Non-Transmitting Meters RSM
Senior Citizen Provision RSC

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 11 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	4.90	4.99	0.09	1.8%	99.8	4.90	4.99	0.09	1.8%	99.8
2	50	13.01	13.90	0.89	6.8%	27.8	13.01	13.90	0.89	6.8%	27.8
3	100	22.03	23.80	1.77	8.0%	23.8	22.03	23.80	1.77	8.0%	23.8
4	150	31.04	33.70	2.66	8.6%	22.5	31.04	33.70	2.66	8.6%	22.5
5	200	40.05	43.59	3.54	8.8%	21.8	40.05	43.59	3.54	8.8%	21.8
6	250	49.06	53.49	4.43	9.0%	21.4	49.06	53.49	4.43	9.0%	21.4
7	300	58.08	63.39	5.32	9.2%	21.1	58.08	63.39	5.32	9.2%	21.1
8	350	67.09	73.29	6.20	9.2%	20.9	67.09	73.29	6.20	9.2%	20.9
9	400	76.10	83.19	7.09	9.3%	20.8	76.10	83.19	7.09	9.3%	20.8
10	450	85.11	93.09	7.97	9.4%	20.7	85.11	93.09	7.97	9.4%	20.7
11	500	94.13	102.99	8.86	9.4%	20.6	94.13	102.99	8.86	9.4%	20.6
12	550	103.14	112.89	9.75	9.4%	20.5	103.14	112.89	9.75	9.4%	20.5
13	600	112.15	122.78	10.63	9.5%	20.5	112.15	122.78	10.63	9.5%	20.5
14	650	124.61	136.37	11.76	9.4%	21.0	121.17	132.68	11.52	9.5%	20.4
15	700	137.07	149.95	12.88	9.4%	21.4	130.18	142.58	12.40	9.5%	20.4
16	750	149.53	163.53	14.00	9.4%	21.8	139.19	152.48	13.29	9.5%	20.3
17	800	161.99	177.11	15.13	9.3%	22.1	148.20	162.38	14.18	9.6%	20.3
18	850	174.44	190.70	16.25	9.3%	22.4	157.22	172.28	15.06	9.6%	20.3
19	900	186.90	204.28	17.38	9.3%	22.7	166.23	182.18	15.95	9.6%	20.2
20	950	199.36	217.86	18.50	9.3%	22.9	175.24	192.08	16.83	9.6%	20.2
21	1,000	211.82	231.44	19.63	9.3%	23.1	184.26	201.97	17.72	9.6%	20.2
22	1,500	336.40	367.27	30.87	9.2%	24.5	274.38	300.96	26.58	9.7%	20.1
23	2,000	460.98	503.10	42.11	9.1%	25.2	364.51	399.95	35.44	9.7%	20.0
24	2,500	585.56	638.92	53.36	9.1%	25.6	454.64	498.94	44.30	9.7%	20.0
25	3,000	710.15	774.75	64.60	9.1%	25.8	544.77	597.92	53.16	9.8%	19.9
26	3,500	834.73	910.57	75.85	9.1%	26.0	634.89	696.91	62.02	9.8%	19.9
27	4,000	959.31	1,046.40	87.09	9.1%	26.2	725.02	795.90	70.88	9.8%	19.9
28	4,500	1,083.89	1,182.22	98.33	9.1%	26.3	815.15	894.88	79.74	9.8%	19.9
29	5,000	1,208.47	1,318.05	109.58	9.1%	26.4	905.28	993.87	88.59	9.8%	19.9

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Residential Non-Transmitting Meters RSM
Income Assistance Provision RIA

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	5	4.90	4.99	0.09	1.8%	99.8	4.90	4.99	0.09	1.8%	99.8
2	50	13.01	13.90	0.89	6.8%	27.8	13.01	13.90	0.89	6.8%	27.8
3	100	22.03	23.80	1.77	8.0%	23.8	22.03	23.80	1.77	8.0%	23.8
4	150	31.04	33.70	2.66	8.6%	22.5	31.04	33.70	2.66	8.6%	22.5
5	200	40.05	43.59	3.54	8.8%	21.8	40.05	43.59	3.54	8.8%	21.8
6	250	49.06	53.49	4.43	9.0%	21.4	49.06	53.49	4.43	9.0%	21.4
7	300	58.08	63.39	5.32	9.2%	21.1	58.08	63.39	5.32	9.2%	21.1
8	350	67.09	73.29	6.20	9.2%	20.9	67.09	73.29	6.20	9.2%	20.9
9	400	76.10	83.19	7.09	9.3%	20.8	76.10	83.19	7.09	9.3%	20.8
10	450	85.11	93.09	7.97	9.4%	20.7	85.11	93.09	7.97	9.4%	20.7
11	500	94.13	102.99	8.86	9.4%	20.6	94.13	102.99	8.86	9.4%	20.6
12	550	103.14	112.89	9.75	9.4%	20.5	103.14	112.89	9.75	9.4%	20.5
13	600	112.15	122.78	10.63	9.5%	20.5	112.15	122.78	10.63	9.5%	20.5
14	650	124.61	136.37	11.76	9.4%	21.0	121.17	132.68	11.52	9.5%	20.4
15	700	137.07	149.95	12.88	9.4%	21.4	130.18	142.58	12.40	9.5%	20.4
16	750	149.53	163.53	14.00	9.4%	21.8	139.19	152.48	13.29	9.5%	20.3
17	800	161.99	177.11	15.13	9.3%	22.1	148.20	162.38	14.18	9.6%	20.3
18	850	174.44	190.70	16.25	9.3%	22.4	157.22	172.28	15.06	9.6%	20.3
19	900	186.90	204.28	17.38	9.3%	22.7	166.23	182.18	15.95	9.6%	20.2
20	950	199.36	217.86	18.50	9.3%	22.9	175.24	192.08	16.83	9.6%	20.2
21	1,000	211.82	231.44	19.63	9.3%	23.1	184.26	201.97	17.72	9.6%	20.2
22	1,500	336.40	367.27	30.87	9.2%	24.5	274.38	300.96	26.58	9.7%	20.1
23	2,000	460.98	503.10	42.11	9.1%	25.2	364.51	399.95	35.44	9.7%	20.0
24	2,500	585.56	638.92	53.36	9.1%	25.6	454.64	498.94	44.30	9.7%	20.0
25	3,000	710.15	774.75	64.60	9.1%	25.8	544.77	597.92	53.16	9.8%	19.9
26	3,500	834.73	910.57	75.85	9.1%	26.0	634.89	696.91	62.02	9.8%	19.9
27	4,000	959.31	1,046.40	87.09	9.1%	26.2	725.02	795.90	70.88	9.8%	19.9
28	4,500	1,083.89	1,182.22	98.33	9.1%	26.3	815.15	894.88	79.74	9.8%	19.9
29	5,000	1,208.47	1,318.05	109.58	9.1%	26.4	905.28	993.87	88.59	9.8%	19.9

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Energy-only GS

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 13 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	250	65.20	69.42	4.22	6.5%	27.8	58.12	62.11	3.99	6.9%	24.8
2	500	110.40	118.84	8.44	7.6%	23.8	96.24	104.21	7.97	8.3%	20.8
3	750	155.60	168.26	12.65	8.1%	22.4	134.36	146.32	11.96	8.9%	19.5
4	1,000	200.80	217.67	16.87	8.4%	21.8	172.48	188.42	15.94	9.2%	18.8
5	1,500	291.20	316.51	25.31	8.7%	21.1	248.72	272.63	23.91	9.6%	18.2
6	2,000	381.60	415.35	33.74	8.8%	20.8	324.96	356.84	31.89	9.8%	17.8
7	2,500	472.00	514.19	42.18	8.9%	20.6	401.20	441.05	39.86	9.9%	17.6
8	3,000	562.41	613.02	50.62	9.0%	20.4	477.44	525.27	47.83	10.0%	17.5
9	3,500	652.81	711.86	59.05	9.0%	20.3	553.68	609.48	55.80	10.1%	17.4
10	4,000	743.21	810.70	67.49	9.1%	20.3	629.91	693.69	63.77	10.1%	17.3
11	4,500	833.61	909.53	75.93	9.1%	20.2	706.15	777.90	71.74	10.2%	17.3
12	5,000	924.01	1,008.37	84.36	9.1%	20.2	782.39	862.11	79.71	10.2%	17.2
13	6,000	1,104.81	1,206.05	101.23	9.2%	20.1	934.87	1,030.53	95.66	10.2%	17.2
14	7,000	1,285.61	1,403.72	118.11	9.2%	20.1	1,087.35	1,198.95	111.60	10.3%	17.1
15	8,000	1,466.42	1,601.40	134.98	9.2%	20.0	1,239.83	1,367.37	127.54	10.3%	17.1
16	9,000	1,647.22	1,799.07	151.85	9.2%	20.0	1,392.31	1,535.80	143.49	10.3%	17.1
17	10,000	1,828.02	1,996.74	168.72	9.2%	20.0	1,544.79	1,704.22	159.43	10.3%	17.0
18	15,000	2,732.03	2,985.12	253.09	9.3%	19.9	2,307.18	2,546.33	239.14	10.4%	17.0
19	20,000	3,636.04	3,973.49	337.45	9.3%	19.9	3,069.57	3,388.43	318.86	10.4%	16.9
20	25,000	4,540.05	4,961.86	421.81	9.3%	19.8	3,831.97	4,230.54	398.57	10.4%	16.9
21	30,000	5,444.06	5,950.23	506.17	9.3%	19.8	4,594.36	5,072.65	478.29	10.4%	16.9
22	35,000	6,348.07	6,938.60	590.54	9.3%	19.8	5,356.76	5,914.76	558.00	10.4%	16.9
23	40,000	7,252.08	7,926.98	674.90	9.3%	19.8	6,119.15	6,756.87	637.72	10.4%	16.9
24	45,000	8,156.09	8,915.35	759.26	9.3%	19.8	6,881.54	7,598.98	717.43	10.4%	16.9
25	50,000	9,060.10	9,903.72	843.62	9.3%	19.8	7,643.94	8,441.09	797.15	10.4%	16.9
26	55,000	9,964.11	10,892.09	927.99	9.3%	19.8	8,406.33	9,283.19	876.86	10.4%	16.9
27	60,000	10,868.12	11,880.47	1,012.35	9.3%	19.8	9,168.72	10,125.30	956.58	10.4%	16.9
28	65,000	11,772.13	12,868.84	1,096.71	9.3%	19.8	9,931.12	10,967.41	1,036.29	10.4%	16.9
29	70,000	12,676.14	13,857.21	1,181.07	9.3%	19.8	10,693.51	11,809.52	1,116.01	10.4%	16.9

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Energy-only GS
Education Provision GEI

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 14 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	250	64.95	69.12	4.17	6.4%	27.6	57.87	61.81	3.94	6.8%	24.7
2	500	109.90	118.25	8.35	7.6%	23.6	95.74	103.62	7.88	8.2%	20.7
3	750	154.85	167.37	12.52	8.1%	22.3	133.61	145.43	11.82	8.8%	19.4
4	1,000	199.80	216.50	16.69	8.4%	21.6	171.48	187.24	15.76	9.2%	18.7
5	1,500	289.70	314.74	25.04	8.6%	21.0	247.22	270.86	23.64	9.6%	18.1
6	2,000	379.60	412.99	33.39	8.8%	20.6	322.96	354.48	31.53	9.8%	17.7
7	2,500	469.51	511.24	41.73	8.9%	20.4	398.70	438.11	39.41	9.9%	17.5
8	3,000	559.41	609.49	50.08	9.0%	20.3	474.44	521.73	47.29	10.0%	17.4
9	3,500	649.31	707.73	58.42	9.0%	20.2	550.18	605.35	55.17	10.0%	17.3
10	4,000	739.21	805.98	66.77	9.0%	20.1	625.92	688.97	63.05	10.1%	17.2
11	4,500	829.11	904.23	75.12	9.1%	20.1	701.66	772.59	70.93	10.1%	17.2
12	5,000	919.01	1,002.48	83.46	9.1%	20.0	777.40	856.21	78.82	10.1%	17.1
13	6,000	1,098.81	1,198.97	100.16	9.1%	20.0	928.88	1,023.45	94.58	10.2%	17.1
14	7,000	1,278.62	1,395.47	116.85	9.1%	19.9	1,080.35	1,190.70	110.34	10.2%	17.0
15	8,000	1,458.42	1,591.96	133.54	9.2%	19.9	1,231.83	1,357.94	126.11	10.2%	17.0
16	9,000	1,638.22	1,788.46	150.23	9.2%	19.9	1,383.31	1,525.18	141.87	10.3%	16.9
17	10,000	1,818.02	1,984.95	166.93	9.2%	19.8	1,534.79	1,692.42	157.63	10.3%	16.9
18	15,000	2,717.04	2,967.43	250.39	9.2%	19.8	2,292.19	2,528.64	236.45	10.3%	16.9
19	20,000	3,616.05	3,949.90	333.85	9.2%	19.7	3,049.58	3,364.85	315.26	10.3%	16.8
20	25,000	4,515.06	4,932.38	417.32	9.2%	19.7	3,806.98	4,201.06	394.08	10.4%	16.8
21	30,000	5,414.07	5,914.85	500.78	9.2%	19.7	4,564.38	5,037.27	472.90	10.4%	16.8
22	35,000	6,313.09	6,897.33	584.24	9.3%	19.7	5,321.77	5,873.48	551.71	10.4%	16.8
23	40,000	7,212.10	7,879.80	667.71	9.3%	19.7	6,079.17	6,709.70	630.53	10.4%	16.8
24	45,000	8,111.11	8,862.28	751.17	9.3%	19.7	6,836.56	7,545.91	709.34	10.4%	16.8
25	50,000	9,010.12	9,844.75	834.63	9.3%	19.7	7,593.96	8,382.12	788.16	10.4%	16.8
26	55,000	9,909.13	10,827.23	918.10	9.3%	19.7	8,351.36	9,218.33	866.97	10.4%	16.8
27	60,000	10,808.15	11,809.71	1,001.56	9.3%	19.7	9,108.75	10,054.54	945.79	10.4%	16.8
28	65,000	11,707.16	12,792.18	1,085.02	9.3%	19.7	9,866.15	10,890.75	1,024.61	10.4%	16.8
29	70,000	12,606.17	13,774.66	1,168.49	9.3%	19.7	10,623.54	11,726.97	1,103.42	10.4%	16.8

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Demand GSD

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 15 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	111.46	119.72	8.27	7.4%	23.9	99.91	105.39	5.47	5.5%	21.1
2	1,000	192.91	209.44	16.53	8.6%	20.9	169.83	180.77	10.94	6.4%	18.1
3	1,500	274.37	299.16	24.80	9.0%	19.9	239.74	256.16	16.42	6.8%	17.1
4	2,000	355.82	388.89	33.06	9.3%	19.4	309.66	331.54	21.89	7.1%	16.6
5	2,500	437.28	478.61	41.33	9.5%	19.1	379.57	406.93	27.36	7.2%	16.3
6	3,000	518.74	568.33	49.59	9.6%	18.9	449.48	482.32	32.83	7.3%	16.1
7	3,500	600.19	658.05	57.86	9.6%	18.8	519.40	557.70	38.30	7.4%	15.9
8	4,000	681.65	747.77	66.13	9.7%	18.7	589.31	633.09	43.78	7.4%	15.8
9	4,500	763.10	837.49	74.39	9.7%	18.6	659.23	708.48	49.25	7.5%	15.7
10	5,000	844.56	927.22	82.66	9.8%	18.5	729.14	783.86	54.72	7.5%	15.7
11	6,000	1,007.47	1,106.66	99.19	9.8%	18.4	868.97	934.63	65.66	7.6%	15.6
12	7,000	1,170.38	1,286.10	115.72	9.9%	18.4	1,008.80	1,085.41	76.61	7.6%	15.5
13	8,000	1,333.29	1,465.55	132.25	9.9%	18.3	1,148.63	1,236.18	87.55	7.6%	15.5
14	9,000	1,496.21	1,644.99	148.78	9.9%	18.3	1,288.45	1,386.95	98.50	7.6%	15.4
15	10,000	1,659.12	1,824.43	165.32	10.0%	18.2	1,428.28	1,537.72	109.44	7.7%	15.4
16	11,000	1,822.03	2,003.88	181.85	10.0%	18.2	1,568.11	1,688.50	120.39	7.7%	15.3
17	12,000	1,984.94	2,183.32	198.38	10.0%	18.2	1,707.94	1,839.27	131.33	7.7%	15.3
18	13,000	2,147.85	2,362.76	214.91	10.0%	18.2	1,847.77	1,990.04	142.27	7.7%	15.3
19	14,000	2,310.76	2,542.20	231.44	10.0%	18.2	1,987.59	2,140.81	153.22	7.7%	15.3
20	15,000	2,473.68	2,721.65	247.97	10.0%	18.1	2,127.42	2,291.58	164.16	7.7%	15.3
21	16,000	2,636.59	2,901.09	264.50	10.0%	18.1	2,267.25	2,442.36	175.11	7.7%	15.3
22	17,000	2,799.50	3,080.53	281.04	10.0%	18.1	2,407.08	2,593.13	186.05	7.7%	15.3
23	18,000	2,962.41	3,259.98	297.57	10.0%	18.1	2,546.91	2,743.90	196.99	7.7%	15.2
24	19,000	3,125.32	3,439.42	314.10	10.1%	18.1	2,686.74	2,894.67	207.94	7.7%	15.2
25	20,000	3,288.23	3,618.86	330.63	10.1%	18.1	2,826.56	3,045.45	218.88	7.7%	15.2
26	21,000	3,451.15	3,798.31	347.16	10.1%	18.1	2,966.39	3,196.22	229.83	7.7%	15.2
27	22,000	3,614.06	3,977.75	363.69	10.1%	18.1	3,106.22	3,346.99	240.77	7.8%	15.2
28	23,000	3,776.97	4,157.19	380.23	10.1%	18.1	3,246.05	3,497.76	251.71	7.8%	15.2
29	24,000	3,939.88	4,336.64	396.76	10.1%	18.1	3,385.88	3,648.53	262.66	7.8%	15.2

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Demand GSD
Education Provision GEI

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 16 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	111.05	119.24	8.20	7.4%	23.8	99.50	104.91	5.40	5.4%	21.0
2	1,000	192.09	208.49	16.40	8.5%	20.8	169.01	179.82	10.81	6.4%	18.0
3	1,500	273.14	297.73	24.59	9.0%	19.8	238.51	254.72	16.21	6.8%	17.0
4	2,000	354.18	386.97	32.79	9.3%	19.3	308.02	329.63	21.62	7.0%	16.5
5	2,500	435.23	476.22	40.99	9.4%	19.0	377.52	404.54	27.02	7.2%	16.2
6	3,000	516.28	565.46	49.19	9.5%	18.8	447.03	479.45	32.42	7.3%	16.0
7	3,500	597.32	654.71	57.38	9.6%	18.7	516.53	554.36	37.83	7.3%	15.8
8	4,000	678.37	743.95	65.58	9.7%	18.6	586.03	629.27	43.23	7.4%	15.7
9	4,500	759.41	833.19	73.78	9.7%	18.5	655.54	704.17	48.64	7.4%	15.6
10	5,000	840.46	922.44	81.98	9.8%	18.4	725.04	779.08	54.04	7.5%	15.6
11	6,000	1,002.55	1,100.92	98.37	9.8%	18.3	864.05	928.90	64.85	7.5%	15.5
12	7,000	1,164.64	1,279.41	114.77	9.9%	18.3	1,003.06	1,078.71	75.66	7.5%	15.4
13	8,000	1,326.74	1,457.90	131.16	9.9%	18.2	1,142.07	1,228.53	86.46	7.6%	15.4
14	9,000	1,488.83	1,636.39	147.56	9.9%	18.2	1,281.08	1,378.35	97.27	7.6%	15.3
15	10,000	1,650.92	1,814.87	163.95	9.9%	18.1	1,420.08	1,528.16	108.08	7.6%	15.3
16	11,000	1,813.01	1,993.36	180.35	9.9%	18.1	1,559.09	1,677.98	118.89	7.6%	15.3
17	12,000	1,975.10	2,171.85	196.75	10.0%	18.1	1,698.10	1,827.80	129.70	7.6%	15.2
18	13,000	2,137.19	2,350.34	213.14	10.0%	18.1	1,837.11	1,977.61	140.50	7.6%	15.2
19	14,000	2,299.29	2,528.82	229.54	10.0%	18.1	1,976.12	2,127.43	151.31	7.7%	15.2
20	15,000	2,461.38	2,707.31	245.93	10.0%	18.0	2,115.13	2,277.25	162.12	7.7%	15.2
21	16,000	2,623.47	2,885.80	262.33	10.0%	18.0	2,254.13	2,427.06	172.93	7.7%	15.2
22	17,000	2,785.56	3,064.29	278.72	10.0%	18.0	2,393.14	2,576.88	183.74	7.7%	15.2
23	18,000	2,947.65	3,242.77	295.12	10.0%	18.0	2,532.15	2,726.70	194.54	7.7%	15.1
24	19,000	3,109.75	3,421.26	311.51	10.0%	18.0	2,671.16	2,876.51	205.35	7.7%	15.1
25	20,000	3,271.84	3,599.75	327.91	10.0%	18.0	2,810.17	3,026.33	216.16	7.7%	15.1
26	21,000	3,433.93	3,778.23	344.30	10.0%	18.0	2,949.18	3,176.14	226.97	7.7%	15.1
27	22,000	3,596.02	3,956.72	360.70	10.0%	18.0	3,088.19	3,325.96	237.78	7.7%	15.1
28	23,000	3,758.11	4,135.21	377.10	10.0%	18.0	3,227.19	3,475.78	248.58	7.7%	15.1
29	24,000	3,920.21	4,313.70	393.49	10.0%	18.0	3,366.20	3,625.59	259.39	7.7%	15.1

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Time-of-Use GSTU

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 17 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	119.67	128.26	8.59	7.2%	25.7	95.55	103.47	7.92	8.3%	20.7
2	1,000	219.33	236.52	17.19	7.8%	23.7	171.10	186.95	15.85	9.3%	18.7
3	1,500	319.00	344.78	25.78	8.1%	23.0	246.65	270.42	23.77	9.6%	18.0
4	2,000	418.66	453.04	34.37	8.2%	22.7	322.20	353.90	31.70	9.8%	17.7
5	2,500	518.33	561.30	42.97	8.3%	22.5	397.75	437.37	39.62	10.0%	17.5
6	3,000	618.00	669.56	51.56	8.3%	22.3	473.30	520.85	47.55	10.0%	17.4
7	3,500	717.66	777.82	60.15	8.4%	22.2	548.85	604.32	55.47	10.1%	17.3
8	4,000	817.33	886.08	68.75	8.4%	22.2	624.40	687.80	63.40	10.2%	17.2
9	4,500	916.99	994.34	77.34	8.4%	22.1	699.95	771.27	71.32	10.2%	17.1
10	5,000	1,016.66	1,102.60	85.94	8.5%	22.1	775.50	854.75	79.25	10.2%	17.1
11	6,000	1,215.99	1,319.11	103.12	8.5%	22.0	926.60	1,021.70	95.10	10.3%	17.0
12	7,000	1,415.32	1,535.63	120.31	8.5%	21.9	1,077.70	1,188.65	110.95	10.3%	17.0
13	8,000	1,614.66	1,752.15	137.50	8.5%	21.9	1,228.80	1,355.60	126.80	10.3%	16.9
14	9,000	1,813.99	1,968.67	154.68	8.5%	21.9	1,379.90	1,522.55	142.65	10.3%	16.9
15	10,000	2,013.32	2,185.19	171.87	8.5%	21.9	1,531.00	1,689.50	158.50	10.4%	16.9
16	11,000	2,212.65	2,401.71	189.06	8.5%	21.8	1,682.10	1,856.45	174.35	10.4%	16.9
17	12,000	2,411.99	2,618.23	206.24	8.6%	21.8	1,833.20	2,023.39	190.20	10.4%	16.9
18	13,000	2,611.32	2,834.75	223.43	8.6%	21.8	1,984.30	2,190.34	206.05	10.4%	16.8
19	14,000	2,810.65	3,051.27	240.62	8.6%	21.8	2,135.40	2,357.29	221.90	10.4%	16.8
20	15,000	3,009.98	3,267.79	257.81	8.6%	21.8	2,286.50	2,524.24	237.75	10.4%	16.8
21	16,000	3,209.31	3,484.31	274.99	8.6%	21.8	2,437.60	2,691.19	253.60	10.4%	16.8
22	17,000	3,408.65	3,700.83	292.18	8.6%	21.8	2,588.70	2,858.14	269.45	10.4%	16.8
23	18,000	3,607.98	3,917.34	309.37	8.6%	21.8	2,739.80	3,025.09	285.30	10.4%	16.8
24	19,000	3,807.31	4,133.86	326.55	8.6%	21.8	2,890.90	3,192.04	301.15	10.4%	16.8
25	20,000	4,006.64	4,350.38	343.74	8.6%	21.8	3,042.00	3,358.99	316.99	10.4%	16.8
26	21,000	4,205.97	4,566.90	360.93	8.6%	21.7	3,193.10	3,525.94	332.84	10.4%	16.8
27	22,000	4,405.31	4,783.42	378.12	8.6%	21.7	3,344.20	3,692.89	348.69	10.4%	16.8
28	23,000	4,604.64	4,999.94	395.30	8.6%	21.7	3,495.30	3,859.84	364.54	10.4%	16.8
29	24,000	4,803.97	5,216.46	412.49	8.6%	21.7	3,646.40	4,026.79	380.39	10.4%	16.8

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Time-of-Use GSTU
Education Provision GEI

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 18 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	119.17	127.67	8.50	7.1%	25.5	95.05	102.89	7.83	8.2%	20.6
2	1,000	218.33	235.34	17.01	7.8%	23.5	170.10	185.77	15.67	9.2%	18.6
3	1,500	317.50	343.01	25.51	8.0%	22.9	245.15	268.66	23.50	9.6%	17.9
4	2,000	416.67	450.68	34.01	8.2%	22.5	320.20	351.54	31.34	9.8%	17.6
5	2,500	515.83	558.35	42.52	8.2%	22.3	395.25	434.43	39.17	9.9%	17.4
6	3,000	615.00	666.02	51.02	8.3%	22.2	470.30	517.31	47.01	10.0%	17.2
7	3,500	714.16	773.69	59.53	8.3%	22.1	545.35	600.20	54.84	10.1%	17.1
8	4,000	813.33	881.36	68.03	8.4%	22.0	620.40	683.08	62.68	10.1%	17.1
9	4,500	912.50	989.03	76.53	8.4%	22.0	695.45	765.97	70.51	10.1%	17.0
10	5,000	1,011.66	1,096.70	85.04	8.4%	21.9	770.50	848.85	78.35	10.2%	17.0
11	6,000	1,210.00	1,312.04	102.04	8.4%	21.9	920.60	1,014.62	94.02	10.2%	16.9
12	7,000	1,408.33	1,527.38	119.05	8.5%	21.8	1,070.70	1,180.39	109.69	10.2%	16.9
13	8,000	1,606.66	1,742.72	136.06	8.5%	21.8	1,220.80	1,346.16	125.36	10.3%	16.8
14	9,000	1,804.99	1,958.06	153.07	8.5%	21.8	1,370.90	1,511.93	141.03	10.3%	16.8
15	10,000	2,003.33	2,173.40	170.07	8.5%	21.7	1,521.00	1,677.70	156.70	10.3%	16.8
16	11,000	2,201.66	2,388.74	187.08	8.5%	21.7	1,671.10	1,843.47	172.37	10.3%	16.8
17	12,000	2,399.99	2,604.08	204.09	8.5%	21.7	1,821.20	2,009.24	188.04	10.3%	16.7
18	13,000	2,598.32	2,819.42	221.09	8.5%	21.7	1,971.30	2,175.01	203.71	10.3%	16.7
19	14,000	2,796.66	3,034.76	238.10	8.5%	21.7	2,121.40	2,340.78	219.38	10.3%	16.7
20	15,000	2,994.99	3,250.10	255.11	8.5%	21.7	2,271.50	2,506.55	235.05	10.3%	16.7
21	16,000	3,193.32	3,465.44	272.12	8.5%	21.7	2,421.60	2,672.32	250.72	10.4%	16.7
22	17,000	3,391.65	3,680.78	289.12	8.5%	21.7	2,571.71	2,838.09	266.39	10.4%	16.7
23	18,000	3,589.99	3,896.12	306.13	8.5%	21.6	2,721.81	3,003.86	282.06	10.4%	16.7
24	19,000	3,788.32	4,111.46	323.14	8.5%	21.6	2,871.91	3,169.63	297.73	10.4%	16.7
25	20,000	3,986.65	4,326.80	340.14	8.5%	21.6	3,022.01	3,335.40	313.40	10.4%	16.7
26	21,000	4,184.98	4,542.14	357.15	8.5%	21.6	3,172.11	3,501.17	329.07	10.4%	16.7
27	22,000	4,383.32	4,757.48	374.16	8.5%	21.6	3,322.21	3,666.94	344.74	10.4%	16.7
28	23,000	4,581.65	4,972.82	391.17	8.5%	21.6	3,472.31	3,832.72	360.41	10.4%	16.7
29	24,000	4,779.98	5,188.16	408.17	8.5%	21.6	3,622.41	3,998.49	376.08	10.4%	16.7

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Time-of-Use GSTU
Secondary Interruptible Provision

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 19 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	108.82	117.39	8.57	7.9%	23.5	84.70	92.60	7.90	9.3%	18.5
2	1,000	197.64	214.78	17.14	8.7%	21.5	149.40	165.21	15.80	10.6%	16.5
3	1,500	286.46	312.17	25.71	9.0%	20.8	214.11	237.81	23.70	11.1%	15.9
4	2,000	375.27	409.55	34.28	9.1%	20.5	278.81	310.42	31.61	11.3%	15.5
5	2,500	464.09	506.94	42.85	9.2%	20.3	343.51	383.02	39.51	11.5%	15.3
6	3,000	552.91	604.33	51.42	9.3%	20.1	408.21	455.62	47.41	11.6%	15.2
7	3,500	641.73	701.72	59.99	9.3%	20.0	472.92	528.23	55.31	11.7%	15.1
8	4,000	730.55	799.11	68.56	9.4%	20.0	537.62	600.83	63.21	11.8%	15.0
9	4,500	819.37	896.50	77.13	9.4%	19.9	602.32	673.43	71.11	11.8%	15.0
10	5,000	908.18	993.89	85.70	9.4%	19.9	667.02	746.04	79.02	11.8%	14.9
11	6,000	1,085.82	1,188.66	102.84	9.5%	19.8	796.43	891.25	94.82	11.9%	14.9
12	7,000	1,263.46	1,383.44	119.98	9.5%	19.8	925.83	1,036.45	110.62	11.9%	14.8
13	8,000	1,441.09	1,578.22	137.12	9.5%	19.7	1,055.24	1,181.66	126.43	12.0%	14.8
14	9,000	1,618.73	1,772.99	154.26	9.5%	19.7	1,184.64	1,326.87	142.23	12.0%	14.7
15	10,000	1,796.37	1,967.77	171.41	9.5%	19.7	1,314.04	1,472.08	158.03	12.0%	14.7
16	11,000	1,974.00	2,162.55	188.55	9.6%	19.7	1,443.45	1,617.28	173.84	12.0%	14.7
17	12,000	2,151.64	2,357.33	205.69	9.6%	19.6	1,572.85	1,762.49	189.64	12.1%	14.7
18	13,000	2,329.28	2,552.10	222.83	9.6%	19.6	1,702.26	1,907.70	205.44	12.1%	14.7
19	14,000	2,506.91	2,746.88	239.97	9.6%	19.6	1,831.66	2,052.91	221.24	12.1%	14.7
20	15,000	2,684.55	2,941.66	257.11	9.6%	19.6	1,961.07	2,198.11	237.05	12.1%	14.7
21	16,000	2,862.19	3,136.44	274.25	9.6%	19.6	2,090.47	2,343.32	252.85	12.1%	14.6
22	17,000	3,039.82	3,331.21	291.39	9.6%	19.6	2,219.87	2,488.53	268.65	12.1%	14.6
23	18,000	3,217.46	3,525.99	308.53	9.6%	19.6	2,349.28	2,633.74	284.46	12.1%	14.6
24	19,000	3,395.10	3,720.77	325.67	9.6%	19.6	2,478.68	2,778.94	300.26	12.1%	14.6
25	20,000	3,572.73	3,915.54	342.81	9.6%	19.6	2,608.09	2,924.15	316.06	12.1%	14.6
26	21,000	3,750.37	4,110.32	359.95	9.6%	19.6	2,737.49	3,069.36	331.87	12.1%	14.6
27	22,000	3,928.01	4,305.10	377.09	9.6%	19.6	2,866.90	3,214.57	347.67	12.1%	14.6
28	23,000	4,105.64	4,499.88	394.23	9.6%	19.6	2,996.30	3,359.77	363.47	12.1%	14.6
29	24,000	4,283.28	4,694.65	411.37	9.6%	19.6	3,125.71	3,504.98	379.28	12.1%	14.6

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP Voltage Level 1

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 20 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	151.90	152.79	0.89	0.6%	30.6	140.00	140.70	0.71	0.5%	28.1
2	1,000	203.79	205.57	1.78	0.9%	20.6	179.99	181.40	1.41	0.8%	18.1
3	1,500	255.69	258.36	2.67	1.0%	17.2	219.99	222.11	2.12	1.0%	14.8
4	2,000	307.59	311.15	3.56	1.2%	15.6	259.98	262.81	2.83	1.1%	13.1
5	2,500	359.48	363.93	4.45	1.2%	14.6	299.98	303.51	3.53	1.2%	12.1
6	3,000	411.38	416.72	5.34	1.3%	13.9	339.98	344.21	4.24	1.2%	11.5
7	4,000	515.17	522.29	7.12	1.4%	13.1	419.97	425.62	5.65	1.3%	10.6
8	5,000	618.97	627.87	8.90	1.4%	12.6	499.96	507.02	7.06	1.4%	10.1
9	6,000	722.76	733.44	10.68	1.5%	12.2	579.95	588.43	8.48	1.5%	9.8
10	7,000	826.55	839.02	12.46	1.5%	12.0	659.94	669.83	9.89	1.5%	9.6
11	8,000	930.35	944.59	14.24	1.5%	11.8	739.94	751.24	11.30	1.5%	9.4
12	9,000	1,034.14	1,050.16	16.02	1.5%	11.7	819.93	832.64	12.71	1.6%	9.3
13	10,000	1,137.93	1,155.74	17.80	1.6%	11.6	899.92	914.05	14.13	1.6%	9.1
14	15,000	1,656.90	1,683.60	26.70	1.6%	11.2	1,299.88	1,321.07	21.19	1.6%	8.8
15	20,000	2,175.87	2,211.47	35.60	1.6%	11.1	1,699.84	1,728.09	28.25	1.7%	8.6
16	25,000	2,694.83	2,739.34	44.50	1.7%	11.0	2,099.80	2,135.12	35.31	1.7%	8.5
17	30,000	3,213.80	3,267.21	53.41	1.7%	10.9	2,499.76	2,542.14	42.38	1.7%	8.5
18	35,000	3,732.77	3,795.08	62.31	1.7%	10.8	2,899.72	2,949.16	49.44	1.7%	8.4
19	40,000	4,251.74	4,322.94	71.21	1.7%	10.8	3,299.69	3,356.19	56.50	1.7%	8.4
20	45,000	4,770.70	4,850.81	80.11	1.7%	10.8	3,699.65	3,763.21	63.56	1.7%	8.4
21	50,000	5,289.67	5,378.68	89.01	1.7%	10.8	4,099.61	4,170.23	70.63	1.7%	8.3
22	60,000	6,327.60	6,434.41	106.81	1.7%	10.7	4,899.53	4,984.28	84.75	1.7%	8.3
23	70,000	7,365.54	7,490.15	124.61	1.7%	10.7	5,699.45	5,798.33	98.88	1.7%	8.3
24	80,000	8,403.47	8,545.89	142.42	1.7%	10.7	6,499.37	6,612.37	113.00	1.7%	8.3
25	90,000	9,441.40	9,601.62	160.22	1.7%	10.7	7,299.29	7,426.42	127.13	1.7%	8.3
26	100,000	10,479.34	10,657.36	178.02	1.7%	10.7	8,099.21	8,240.47	141.25	1.7%	8.2
27	110,000	11,517.27	11,713.09	195.82	1.7%	10.6	8,899.13	9,054.51	155.38	1.7%	8.2
28	120,000	12,555.21	12,768.83	213.62	1.7%	10.6	9,699.06	9,868.56	169.50	1.7%	8.2
29	130,000	13,593.14	13,824.56	231.42	1.7%	10.6	10,498.98	10,682.60	183.63	1.7%	8.2

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP Voltage Level 1
Education Provision GEI

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 21 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	151.61	152.46	0.85	0.6%	30.5	139.71	140.38	0.67	0.5%	28.1
2	1,000	203.22	204.92	1.71	0.8%	20.5	179.41	180.76	1.34	0.7%	18.1
3	1,500	254.82	257.39	2.56	1.0%	17.2	219.12	221.13	2.01	0.9%	14.7
4	2,000	306.43	309.85	3.42	1.1%	15.5	258.83	261.51	2.68	1.0%	13.1
5	2,500	358.04	362.31	4.27	1.2%	14.5	298.54	301.89	3.35	1.1%	12.1
6	3,000	409.65	414.77	5.13	1.3%	13.8	338.24	342.27	4.02	1.2%	11.4
7	4,000	512.86	519.70	6.84	1.3%	13.0	417.66	423.02	5.36	1.3%	10.6
8	5,000	616.08	624.62	8.54	1.4%	12.5	497.07	503.78	6.71	1.3%	10.1
9	6,000	719.29	729.55	10.25	1.4%	12.2	576.48	584.53	8.05	1.4%	9.7
10	7,000	822.51	834.47	11.96	1.5%	11.9	655.90	665.29	9.39	1.4%	9.5
11	8,000	925.72	939.39	13.67	1.5%	11.7	735.31	746.04	10.73	1.5%	9.3
12	9,000	1,028.94	1,044.32	15.38	1.5%	11.6	814.73	826.80	12.07	1.5%	9.2
13	10,000	1,132.15	1,149.24	17.09	1.5%	11.5	894.14	907.55	13.41	1.5%	9.1
14	15,000	1,648.23	1,673.86	25.63	1.6%	11.2	1,291.21	1,311.33	20.12	1.6%	8.7
15	20,000	2,164.31	2,198.48	34.18	1.6%	11.0	1,688.28	1,715.11	26.82	1.6%	8.6
16	25,000	2,680.38	2,723.11	42.72	1.6%	10.9	2,085.35	2,118.88	33.53	1.6%	8.5
17	30,000	3,196.46	3,247.73	51.26	1.6%	10.8	2,482.42	2,522.66	40.23	1.6%	8.4
18	35,000	3,712.54	3,772.35	59.81	1.6%	10.8	2,879.49	2,926.44	46.94	1.6%	8.4
19	40,000	4,228.62	4,296.97	68.35	1.6%	10.7	3,276.57	3,330.21	53.65	1.6%	8.3
20	45,000	4,744.69	4,821.59	76.90	1.6%	10.7	3,673.64	3,733.99	60.35	1.6%	8.3
21	50,000	5,260.77	5,346.21	85.44	1.6%	10.7	4,070.71	4,137.76	67.06	1.6%	8.3
22	60,000	6,292.92	6,395.45	102.53	1.6%	10.7	4,864.85	4,945.32	80.47	1.7%	8.2
23	70,000	7,325.08	7,444.69	119.62	1.6%	10.6	5,658.99	5,752.87	93.88	1.7%	8.2
24	80,000	8,357.23	8,493.94	136.71	1.6%	10.6	6,453.13	6,560.42	107.29	1.7%	8.2
25	90,000	9,389.38	9,543.18	153.79	1.6%	10.6	7,247.27	7,367.98	120.70	1.7%	8.2
26	100,000	10,421.54	10,592.42	170.88	1.6%	10.6	8,041.41	8,175.53	134.12	1.7%	8.2
27	110,000	11,453.69	11,641.66	187.97	1.6%	10.6	8,835.55	8,983.08	147.53	1.7%	8.2
28	120,000	12,485.85	12,690.91	205.06	1.6%	10.6	9,629.70	9,790.63	160.94	1.7%	8.2
29	130,000	13,518.00	13,740.15	222.15	1.6%	10.6	10,423.84	10,598.19	174.35	1.7%	8.2

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP Voltage Level 2

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 22 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	154.51	155.60	1.10	0.7%	31.1	142.45	143.36	0.91	0.6%	28.7
2	1,000	209.02	211.21	2.19	1.0%	21.1	184.90	186.72	1.82	1.0%	18.7
3	1,500	263.53	266.81	3.29	1.2%	17.8	227.35	230.09	2.73	1.2%	15.3
4	2,000	318.03	322.42	4.39	1.4%	16.1	269.80	273.45	3.64	1.4%	13.7
5	2,500	372.54	378.02	5.48	1.5%	15.1	312.26	316.81	4.55	1.5%	12.7
6	3,000	427.05	433.63	6.58	1.5%	14.5	354.71	360.17	5.47	1.5%	12.0
7	4,000	536.07	544.84	8.77	1.6%	13.6	439.61	446.90	7.29	1.7%	11.2
8	5,000	645.08	656.05	10.96	1.7%	13.1	524.51	533.62	9.11	1.7%	10.7
9	6,000	754.10	767.26	13.16	1.7%	12.8	609.41	620.34	10.93	1.8%	10.3
10	7,000	863.12	878.47	15.35	1.8%	12.5	694.32	707.07	12.75	1.8%	10.1
11	8,000	972.14	989.68	17.54	1.8%	12.4	779.22	793.79	14.58	1.9%	9.9
12	9,000	1,081.15	1,100.89	19.73	1.8%	12.2	864.12	880.52	16.40	1.9%	9.8
13	10,000	1,190.17	1,212.10	21.93	1.8%	12.1	949.02	967.24	18.22	1.9%	9.7
14	15,000	1,735.25	1,768.14	32.89	1.9%	11.8	1,373.53	1,400.86	27.33	2.0%	9.3
15	20,000	2,280.34	2,324.19	43.85	1.9%	11.6	1,798.04	1,834.48	36.44	2.0%	9.2
16	25,000	2,825.42	2,880.24	54.82	1.9%	11.5	2,222.55	2,268.10	45.55	2.0%	9.1
17	30,000	3,370.51	3,436.29	65.78	2.0%	11.5	2,647.06	2,701.72	54.66	2.1%	9.0
18	35,000	3,915.59	3,992.33	76.74	2.0%	11.4	3,071.58	3,135.34	63.77	2.1%	9.0
19	40,000	4,460.68	4,548.38	87.70	2.0%	11.4	3,496.09	3,568.96	72.88	2.1%	8.9
20	45,000	5,005.76	5,104.43	98.67	2.0%	11.3	3,920.60	4,002.58	81.99	2.1%	8.9
21	50,000	5,550.85	5,660.48	109.63	2.0%	11.3	4,345.11	4,436.20	91.10	2.1%	8.9
22	60,000	6,641.02	6,772.57	131.56	2.0%	11.3	5,194.13	5,303.45	109.32	2.1%	8.8
23	70,000	7,731.19	7,884.67	153.48	2.0%	11.3	6,043.15	6,170.69	127.53	2.1%	8.8
24	80,000	8,821.36	8,996.76	175.41	2.0%	11.2	6,892.17	7,037.93	145.75	2.1%	8.8
25	90,000	9,911.52	10,108.86	197.34	2.0%	11.2	7,741.19	7,905.17	163.97	2.1%	8.8
26	100,000	11,001.69	11,220.96	219.26	2.0%	11.2	8,590.22	8,772.41	182.19	2.1%	8.8
27	110,000	12,091.86	12,333.05	241.19	2.0%	11.2	9,439.24	9,639.65	200.41	2.1%	8.8
28	120,000	13,182.03	13,445.15	263.11	2.0%	11.2	10,288.26	10,506.89	218.63	2.1%	8.8
29	130,000	14,272.20	14,557.24	285.04	2.0%	11.2	11,137.28	11,374.13	236.85	2.1%	8.7

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP Voltage Level 2
Education Provision GEI

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	154.22	155.28	1.06	0.7%	31.1	142.16	143.04	0.88	0.6%	28.6
2	1,000	208.44	210.56	2.12	1.0%	21.1	184.32	186.07	1.75	0.9%	18.6
3	1,500	262.66	265.84	3.18	1.2%	17.7	226.49	229.11	2.63	1.2%	15.3
4	2,000	316.88	321.12	4.24	1.3%	16.1	268.65	272.15	3.50	1.3%	13.6
5	2,500	371.10	376.40	5.30	1.4%	15.1	310.81	315.19	4.38	1.4%	12.6
6	3,000	425.32	431.68	6.36	1.5%	14.4	352.97	358.22	5.25	1.5%	11.9
7	4,000	533.76	542.24	8.49	1.6%	13.6	437.30	444.30	7.00	1.6%	11.1
8	5,000	642.19	652.80	10.61	1.7%	13.1	521.62	530.37	8.75	1.7%	10.6
9	6,000	750.63	763.36	12.73	1.7%	12.7	605.94	616.45	10.50	1.7%	10.3
10	7,000	859.07	873.92	14.85	1.7%	12.5	690.27	702.52	12.25	1.8%	10.0
11	8,000	967.51	984.48	16.97	1.8%	12.3	774.59	788.60	14.00	1.8%	9.9
12	9,000	1,075.95	1,095.04	19.09	1.8%	12.2	858.92	874.67	15.76	1.8%	9.7
13	10,000	1,184.39	1,205.60	21.21	1.8%	12.1	943.24	960.75	17.51	1.9%	9.6
14	15,000	1,726.58	1,758.40	31.82	1.8%	11.7	1,364.86	1,391.12	26.26	1.9%	9.3
15	20,000	2,268.78	2,311.20	42.43	1.9%	11.6	1,786.48	1,821.49	35.01	2.0%	9.1
16	25,000	2,810.97	2,864.00	53.03	1.9%	11.5	2,208.10	2,251.87	43.76	2.0%	9.0
17	30,000	3,353.17	3,416.81	63.64	1.9%	11.4	2,629.72	2,682.24	52.52	2.0%	8.9
18	35,000	3,895.36	3,969.61	74.24	1.9%	11.3	3,051.35	3,112.62	61.27	2.0%	8.9
19	40,000	4,437.56	4,522.41	84.85	1.9%	11.3	3,472.97	3,542.99	70.02	2.0%	8.9
20	45,000	4,979.75	5,075.21	95.46	1.9%	11.3	3,894.59	3,973.36	78.78	2.0%	8.8
21	50,000	5,521.95	5,628.01	106.06	1.9%	11.3	4,316.21	4,403.74	87.53	2.0%	8.8
22	60,000	6,606.34	6,733.61	127.28	1.9%	11.2	5,159.45	5,264.48	105.03	2.0%	8.8
23	70,000	7,690.73	7,839.21	148.49	1.9%	11.2	6,002.69	6,125.23	122.54	2.0%	8.8
24	80,000	8,775.12	8,944.82	169.70	1.9%	11.2	6,845.93	6,985.98	140.05	2.0%	8.7
25	90,000	9,859.50	10,050.42	190.91	1.9%	11.2	7,689.17	7,846.72	157.55	2.0%	8.7
26	100,000	10,943.89	11,156.02	212.13	1.9%	11.2	8,532.42	8,707.47	175.06	2.1%	8.7
27	110,000	12,028.28	12,261.62	233.34	1.9%	11.1	9,375.66	9,568.22	192.56	2.1%	8.7
28	120,000	13,112.67	13,367.22	254.55	1.9%	11.1	10,218.90	10,428.97	210.07	2.1%	8.7
29	130,000	14,197.06	14,472.83	275.76	1.9%	11.1	11,062.14	11,289.71	227.57	2.1%	8.7

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP Voltage Level 3

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 24 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	161.87	164.62	2.76	1.7%	32.9	149.65	152.23	2.58	1.7%	30.4
2	1,000	223.73	229.24	5.51	2.5%	22.9	199.30	204.46	5.16	2.6%	20.4
3	1,500	285.60	293.86	8.27	2.9%	19.6	248.95	256.69	7.74	3.1%	17.1
4	2,000	347.46	358.48	11.02	3.2%	17.9	298.60	308.92	10.32	3.5%	15.4
5	2,500	409.33	423.10	13.78	3.4%	16.9	348.25	361.15	12.89	3.7%	14.4
6	3,000	471.19	487.72	16.53	3.5%	16.3	397.91	413.38	15.47	3.9%	13.8
7	4,000	594.92	616.96	22.04	3.7%	15.4	497.21	517.84	20.63	4.1%	12.9
8	5,000	718.65	746.21	27.55	3.8%	14.9	596.51	622.30	25.79	4.3%	12.4
9	6,000	842.38	875.45	33.06	3.9%	14.6	695.81	726.76	30.95	4.4%	12.1
10	7,000	966.12	1,004.69	38.57	4.0%	14.4	795.11	831.22	36.10	4.5%	11.9
11	8,000	1,089.85	1,133.93	44.08	4.0%	14.2	894.42	935.68	41.26	4.6%	11.7
12	9,000	1,213.58	1,263.17	49.59	4.1%	14.0	993.72	1,040.14	46.42	4.7%	11.6
13	10,000	1,337.31	1,392.41	55.10	4.1%	13.9	1,093.02	1,144.60	51.58	4.7%	11.4
14	15,000	1,955.96	2,038.62	82.66	4.2%	13.6	1,589.53	1,666.89	77.37	4.9%	11.1
15	20,000	2,574.62	2,684.82	110.21	4.3%	13.4	2,086.04	2,189.19	103.15	4.9%	10.9
16	25,000	3,193.27	3,331.03	137.76	4.3%	13.3	2,582.55	2,711.49	128.94	5.0%	10.8
17	30,000	3,811.92	3,977.23	165.31	4.3%	13.3	3,079.06	3,233.79	154.73	5.0%	10.8
18	35,000	4,430.58	4,623.44	192.86	4.4%	13.2	3,575.57	3,756.09	180.52	5.0%	10.7
19	40,000	5,049.23	5,269.65	220.41	4.4%	13.2	4,072.08	4,278.38	206.31	5.1%	10.7
20	45,000	5,667.88	5,915.85	247.97	4.4%	13.1	4,568.59	4,800.68	232.10	5.1%	10.7
21	50,000	6,286.54	6,562.06	275.52	4.4%	13.1	5,065.09	5,322.98	257.89	5.1%	10.6
22	60,000	7,523.85	7,854.47	330.62	4.4%	13.1	6,058.11	6,367.58	309.46	5.1%	10.6
23	70,000	8,761.15	9,146.88	385.73	4.4%	13.1	7,051.13	7,412.17	361.04	5.1%	10.6
24	80,000	9,998.46	10,439.29	440.83	4.4%	13.0	8,044.15	8,456.77	412.62	5.1%	10.6
25	90,000	11,235.77	11,731.70	495.93	4.4%	13.0	9,037.17	9,501.36	464.19	5.1%	10.6
26	100,000	12,473.08	13,024.11	551.04	4.4%	13.0	10,030.19	10,545.96	515.77	5.1%	10.5
27	110,000	13,710.38	14,316.52	606.14	4.4%	13.0	11,023.21	11,590.56	567.35	5.1%	10.5
28	120,000	14,947.69	15,608.94	661.24	4.4%	13.0	12,016.23	12,635.15	618.92	5.2%	10.5
29	130,000	16,185.00	16,901.35	716.35	4.4%	13.0	13,009.25	13,679.75	670.50	5.2%	10.5

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP Voltage Level 3
Education Provision GEI

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 25 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	161.58	164.30	2.72	1.7%	32.9	149.36	151.91	2.54	1.7%	30.4
2	1,000	223.15	228.59	5.44	2.4%	22.9	198.72	203.81	5.09	2.6%	20.4
3	1,500	284.73	292.89	8.16	2.9%	19.5	248.09	255.72	7.63	3.1%	17.0
4	2,000	346.31	357.18	10.88	3.1%	17.9	297.45	307.62	10.17	3.4%	15.4
5	2,500	407.88	421.48	13.60	3.3%	16.9	346.81	359.53	12.72	3.7%	14.4
6	3,000	469.46	485.78	16.32	3.5%	16.2	396.17	411.43	15.26	3.9%	13.7
7	4,000	592.61	614.37	21.76	3.7%	15.4	494.90	515.24	20.35	4.1%	12.9
8	5,000	715.76	742.96	27.19	3.8%	14.9	593.62	619.05	25.43	4.3%	12.4
9	6,000	838.92	871.55	32.63	3.9%	14.5	692.34	722.86	30.52	4.4%	12.0
10	7,000	962.07	1,000.14	38.07	4.0%	14.3	791.07	826.67	35.60	4.5%	11.8
11	8,000	1,085.22	1,128.73	43.51	4.0%	14.1	889.79	930.48	40.69	4.6%	11.6
12	9,000	1,208.37	1,257.33	48.95	4.1%	14.0	988.52	1,034.29	45.78	4.6%	11.5
13	10,000	1,331.53	1,385.92	54.39	4.1%	13.9	1,087.24	1,138.10	50.86	4.7%	11.4
14	15,000	1,947.29	2,028.88	81.58	4.2%	13.5	1,580.86	1,657.15	76.30	4.8%	11.0
15	20,000	2,563.06	2,671.84	108.78	4.2%	13.4	2,074.48	2,176.20	101.73	4.9%	10.9
16	25,000	3,178.82	3,314.79	135.97	4.3%	13.3	2,568.10	2,695.26	127.16	5.0%	10.8
17	30,000	3,794.58	3,957.75	163.17	4.3%	13.2	3,061.72	3,214.31	152.59	5.0%	10.7
18	35,000	4,410.35	4,600.71	190.36	4.3%	13.1	3,555.34	3,733.36	178.02	5.0%	10.7
19	40,000	5,026.11	5,243.67	217.56	4.3%	13.1	4,048.96	4,252.41	203.45	5.0%	10.6
20	45,000	5,641.87	5,886.63	244.75	4.3%	13.1	4,542.58	4,771.46	228.89	5.0%	10.6
21	50,000	6,257.64	6,529.59	271.95	4.3%	13.1	5,036.19	5,290.51	254.32	5.0%	10.6
22	60,000	7,489.17	7,815.51	326.34	4.4%	13.0	6,023.43	6,328.61	305.18	5.1%	10.5
23	70,000	8,720.69	9,101.42	380.73	4.4%	13.0	7,010.67	7,366.72	356.04	5.1%	10.5
24	80,000	9,952.22	10,387.34	435.12	4.4%	13.0	7,997.91	8,404.82	406.91	5.1%	10.5
25	90,000	11,183.75	11,673.26	489.51	4.4%	13.0	8,985.15	9,442.92	457.77	5.1%	10.5
26	100,000	12,415.28	12,959.18	543.90	4.4%	13.0	9,972.39	10,481.02	508.63	5.1%	10.5
27	110,000	13,646.80	14,245.09	598.29	4.4%	13.0	10,959.63	11,519.13	559.50	5.1%	10.5
28	120,000	14,878.33	15,531.01	652.68	4.4%	12.9	11,946.87	12,557.23	610.36	5.1%	10.5
29	130,000	16,109.86	16,816.93	707.07	4.4%	12.9	12,934.11	13,595.33	661.22	5.1%	10.5

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 1

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 26 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	8.08	8.57	0.49	6.1%	8.6	7.04	7.47	0.43	6.2%	7.5
2	110	8.87	9.41	0.54	6.1%	8.6	7.72	8.20	0.48	6.2%	7.5
3	120	9.66	10.25	0.59	6.1%	8.5	8.41	8.93	0.52	6.2%	7.4
4	130	10.45	11.09	0.64	6.1%	8.5	9.09	9.65	0.57	6.2%	7.4
5	140	11.24	11.92	0.69	6.1%	8.5	9.77	10.38	0.61	6.2%	7.4
6	150	12.02	12.76	0.74	6.1%	8.5	10.46	11.11	0.65	6.2%	7.4
7	200	15.97	16.95	0.98	6.1%	8.5	13.88	14.75	0.87	6.3%	7.4
8	250	19.91	21.14	1.23	6.2%	8.5	17.29	18.38	1.09	6.3%	7.4
9	300	23.85	25.32	1.47	6.2%	8.4	20.71	22.02	1.30	6.3%	7.3
10	350	27.79	29.51	1.72	6.2%	8.4	24.13	25.66	1.52	6.3%	7.3
11	400	31.73	33.70	1.96	6.2%	8.4	27.55	29.29	1.74	6.3%	7.3
12	450	35.67	37.88	2.21	6.2%	8.4	30.97	32.93	1.96	6.3%	7.3
13	500	39.62	42.07	2.45	6.2%	8.4	34.39	36.56	2.17	6.3%	7.3
14	600	47.50	50.45	2.95	6.2%	8.4	41.23	43.84	2.61	6.3%	7.3
15	700	55.38	58.82	3.44	6.2%	8.4	48.07	51.11	3.04	6.3%	7.3
16	800	63.27	67.19	3.93	6.2%	8.4	54.90	58.38	3.48	6.3%	7.3
17	900	71.15	75.57	4.42	6.2%	8.4	61.74	65.66	3.91	6.3%	7.3
18	1,000	79.03	83.94	4.91	6.2%	8.4	68.58	72.93	4.35	6.3%	7.3
19	1,500	118.45	125.81	7.36	6.2%	8.4	102.77	109.29	6.52	6.3%	7.3
20	2,000	157.87	167.69	9.82	6.2%	8.4	136.96	145.66	8.70	6.4%	7.3
21	2,500	197.28	209.56	12.27	6.2%	8.4	171.15	182.02	10.87	6.4%	7.3
22	3,000	236.70	251.43	14.73	6.2%	8.4	205.34	218.39	13.05	6.4%	7.3
23	3,500	276.12	293.30	17.18	6.2%	8.4	239.53	254.75	15.22	6.4%	7.3
24	4,000	315.53	335.17	19.64	6.2%	8.4	273.72	291.11	17.40	6.4%	7.3
25	4,500	354.95	377.04	22.09	6.2%	8.4	307.90	327.48	19.57	6.4%	7.3
26	5,000	394.37	418.91	24.55	6.2%	8.4	342.09	363.84	21.75	6.4%	7.3
27	5,500	433.78	460.79	27.00	6.2%	8.4	376.28	400.21	23.92	6.4%	7.3
28	6,000	473.20	502.66	29.46	6.2%	8.4	410.47	436.57	26.10	6.4%	7.3
29	6,500	512.62	544.53	31.91	6.2%	8.4	444.66	472.94	28.27	6.4%	7.3

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 1
Primary Interruptible Provision GI

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 27 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	6.60	7.09	0.49	7.4%	7.1	5.73	6.17	0.43	7.6%	6.2
2	110	7.24	7.78	0.54	7.5%	7.1	6.28	6.76	0.48	7.6%	6.1
3	120	7.88	8.47	0.59	7.5%	7.1	6.84	7.36	0.52	7.6%	6.1
4	130	8.52	9.16	0.64	7.5%	7.0	7.39	7.95	0.57	7.7%	6.1
5	140	9.16	9.85	0.69	7.5%	7.0	7.94	8.55	0.61	7.7%	6.1
6	150	9.80	10.54	0.74	7.5%	7.0	8.50	9.15	0.65	7.7%	6.1
7	200	13.00	13.98	0.98	7.6%	7.0	11.26	12.13	0.87	7.7%	6.1
8	250	16.20	17.43	1.23	7.6%	7.0	14.03	15.11	1.09	7.8%	6.0
9	300	19.40	20.88	1.47	7.6%	7.0	16.79	18.10	1.30	7.8%	6.0
10	350	22.61	24.32	1.72	7.6%	6.9	19.56	21.08	1.52	7.8%	6.0
11	400	25.81	27.77	1.96	7.6%	6.9	22.32	24.06	1.74	7.8%	6.0
12	450	29.01	31.22	2.21	7.6%	6.9	25.09	27.04	1.96	7.8%	6.0
13	500	32.21	34.66	2.45	7.6%	6.9	27.85	30.03	2.17	7.8%	6.0
14	600	38.61	41.55	2.95	7.6%	6.9	33.38	35.99	2.61	7.8%	6.0
15	700	45.01	48.45	3.44	7.6%	6.9	38.91	41.96	3.04	7.8%	6.0
16	800	51.41	55.34	3.93	7.6%	6.9	44.44	47.92	3.48	7.8%	6.0
17	900	57.81	62.23	4.42	7.6%	6.9	49.97	53.89	3.91	7.8%	6.0
18	1,000	64.21	69.12	4.91	7.6%	6.9	55.50	59.85	4.35	7.8%	6.0
19	1,500	96.22	103.59	7.36	7.7%	6.9	83.16	89.68	6.52	7.8%	6.0
20	2,000	128.23	138.05	9.82	7.7%	6.9	110.81	119.51	8.70	7.9%	6.0
21	2,500	160.24	172.51	12.27	7.7%	6.9	138.46	149.33	10.87	7.9%	6.0
22	3,000	192.24	206.97	14.73	7.7%	6.9	166.11	179.16	13.05	7.9%	6.0
23	3,500	224.25	241.44	17.18	7.7%	6.9	193.76	208.99	15.22	7.9%	6.0
24	4,000	256.26	275.90	19.64	7.7%	6.9	221.41	238.81	17.40	7.9%	6.0
25	4,500	288.27	310.36	22.09	7.7%	6.9	249.07	268.64	19.57	7.9%	6.0
26	5,000	320.27	344.82	24.55	7.7%	6.9	276.72	298.47	21.75	7.9%	6.0
27	5,500	352.28	379.28	27.00	7.7%	6.9	304.37	328.29	23.92	7.9%	6.0
28	6,000	384.29	413.75	29.46	7.7%	6.9	332.02	358.12	26.10	7.9%	6.0
29	6,500	416.30	448.21	31.91	7.7%	6.9	359.67	387.95	28.27	7.9%	6.0

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 2

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	8.56	9.06	0.50	5.8%	9.1	7.47	7.91	0.44	5.9%	7.9
2	110	9.40	9.95	0.55	5.8%	9.0	8.20	8.68	0.48	5.9%	7.9
3	120	10.24	10.83	0.60	5.8%	9.0	8.92	9.45	0.53	5.9%	7.9
4	130	11.07	11.72	0.65	5.9%	9.0	9.65	10.22	0.57	5.9%	7.9
5	140	11.91	12.61	0.70	5.9%	9.0	10.38	10.99	0.62	5.9%	7.9
6	150	12.74	13.49	0.75	5.9%	9.0	11.10	11.76	0.66	6.0%	7.8
7	200	16.93	17.92	1.00	5.9%	9.0	14.74	15.62	0.88	6.0%	7.8
8	250	21.11	22.35	1.25	5.9%	8.9	18.37	19.47	1.10	6.0%	7.8
9	300	25.29	26.78	1.50	5.9%	8.9	22.01	23.33	1.32	6.0%	7.8
10	350	29.47	31.22	1.75	5.9%	8.9	25.64	27.18	1.54	6.0%	7.8
11	400	33.65	35.65	1.99	5.9%	8.9	29.27	31.04	1.76	6.0%	7.8
12	450	37.83	40.08	2.24	5.9%	8.9	32.91	34.89	1.98	6.0%	7.8
13	500	42.01	44.51	2.49	5.9%	8.9	36.54	38.75	2.20	6.0%	7.7
14	600	50.38	53.37	2.99	5.9%	8.9	43.81	46.45	2.64	6.0%	7.7
15	700	58.74	62.23	3.49	5.9%	8.9	51.08	54.16	3.08	6.0%	7.7
16	800	67.10	71.09	3.99	5.9%	8.9	58.35	61.87	3.52	6.0%	7.7
17	900	75.46	79.95	4.49	5.9%	8.9	65.62	69.58	3.97	6.0%	7.7
18	1,000	83.83	88.81	4.99	5.9%	8.9	72.89	77.29	4.41	6.0%	7.7
19	1,500	125.64	133.12	7.48	6.0%	8.9	109.23	115.84	6.61	6.1%	7.7
20	2,000	167.45	177.43	9.97	6.0%	8.9	145.57	154.38	8.81	6.1%	7.7
21	2,500	209.27	221.74	12.47	6.0%	8.9	181.91	192.93	11.01	6.1%	7.7
22	3,000	251.08	266.04	14.96	6.0%	8.9	218.26	231.47	13.22	6.1%	7.7
23	3,500	292.90	310.35	17.45	6.0%	8.9	254.60	270.02	15.42	6.1%	7.7
24	4,000	334.71	354.66	19.95	6.0%	8.9	290.94	308.57	17.62	6.1%	7.7
25	4,500	376.52	398.96	22.44	6.0%	8.9	327.29	347.11	19.83	6.1%	7.7
26	5,000	418.34	443.27	24.93	6.0%	8.9	363.63	385.66	22.03	6.1%	7.7
27	5,500	460.15	487.58	27.43	6.0%	8.9	399.97	424.20	24.23	6.1%	7.7
28	6,000	501.96	531.89	29.92	6.0%	8.9	436.31	462.75	26.44	6.1%	7.7
29	6,500	543.78	576.19	32.42	6.0%	8.9	472.66	501.29	28.64	6.1%	7.7

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 2
Primary Interruptible Provision GI

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	7.04	7.54	0.50	7.1%	7.5	6.13	6.57	0.44	7.2%	6.6
2	110	7.73	8.27	0.55	7.1%	7.5	6.72	7.20	0.48	7.2%	6.5
3	120	8.41	9.01	0.60	7.1%	7.5	7.31	7.84	0.53	7.2%	6.5
4	130	9.09	9.74	0.65	7.1%	7.5	7.90	8.48	0.57	7.2%	6.5
5	140	9.78	10.48	0.70	7.1%	7.5	8.50	9.11	0.62	7.3%	6.5
6	150	10.46	11.21	0.75	7.2%	7.5	9.09	9.75	0.66	7.3%	6.5
7	200	13.88	14.88	1.00	7.2%	7.4	12.05	12.93	0.88	7.3%	6.5
8	250	17.30	18.55	1.25	7.2%	7.4	15.02	16.12	1.10	7.3%	6.4
9	300	20.72	22.22	1.50	7.2%	7.4	17.98	19.30	1.32	7.4%	6.4
10	350	24.14	25.89	1.75	7.2%	7.4	20.94	22.48	1.54	7.4%	6.4
11	400	27.57	29.56	1.99	7.2%	7.4	23.90	25.67	1.76	7.4%	6.4
12	450	30.99	33.23	2.24	7.2%	7.4	26.87	28.85	1.98	7.4%	6.4
13	500	34.41	36.90	2.49	7.2%	7.4	29.83	32.03	2.20	7.4%	6.4
14	600	41.25	44.24	2.99	7.3%	7.4	35.76	38.40	2.64	7.4%	6.4
15	700	48.09	51.58	3.49	7.3%	7.4	41.68	44.77	3.08	7.4%	6.4
16	800	54.93	58.92	3.99	7.3%	7.4	47.61	51.13	3.52	7.4%	6.4
17	900	61.77	66.26	4.49	7.3%	7.4	53.54	57.50	3.97	7.4%	6.4
18	1,000	68.61	73.60	4.99	7.3%	7.4	59.46	63.87	4.41	7.4%	6.4
19	1,500	102.82	110.30	7.48	7.3%	7.4	89.09	95.70	6.61	7.4%	6.4
20	2,000	137.03	147.00	9.97	7.3%	7.4	118.72	127.53	8.81	7.4%	6.4
21	2,500	171.23	183.70	12.47	7.3%	7.3	148.35	159.37	11.01	7.4%	6.4
22	3,000	205.44	220.40	14.96	7.3%	7.3	177.98	191.20	13.22	7.4%	6.4
23	3,500	239.65	257.10	17.45	7.3%	7.3	207.61	223.04	15.42	7.4%	6.4
24	4,000	273.85	293.80	19.95	7.3%	7.3	237.25	254.87	17.62	7.4%	6.4
25	4,500	308.06	330.50	22.44	7.3%	7.3	266.88	286.70	19.83	7.4%	6.4
26	5,000	342.27	367.20	24.93	7.3%	7.3	296.51	318.54	22.03	7.4%	6.4
27	5,500	376.47	403.90	27.43	7.3%	7.3	326.14	350.37	24.23	7.4%	6.4
28	6,000	410.68	440.60	29.92	7.3%	7.3	355.77	382.20	26.44	7.4%	6.4
29	6,500	444.89	477.30	32.42	7.3%	7.3	385.40	414.04	28.64	7.4%	6.4

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 3

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	9.60	10.25	0.65	6.8%	10.3	8.46	9.05	0.59	6.9%	9.0
2	110	10.54	11.26	0.71	6.8%	10.2	9.29	9.93	0.64	6.9%	9.0
3	120	11.48	12.26	0.78	6.8%	10.2	10.11	10.82	0.70	7.0%	9.0
4	130	12.42	13.27	0.84	6.8%	10.2	10.94	11.70	0.76	7.0%	9.0
5	140	13.36	14.27	0.91	6.8%	10.2	11.76	12.58	0.82	7.0%	9.0
6	150	14.30	15.28	0.97	6.8%	10.2	12.59	13.47	0.88	7.0%	9.0
7	200	19.00	20.30	1.30	6.8%	10.2	16.72	17.89	1.17	7.0%	8.9
8	250	23.70	25.33	1.62	6.9%	10.1	20.85	22.31	1.47	7.0%	8.9
9	300	28.41	30.35	1.95	6.9%	10.1	24.98	26.74	1.76	7.0%	8.9
10	350	33.11	35.38	2.27	6.9%	10.1	29.11	31.16	2.05	7.0%	8.9
11	400	37.81	40.41	2.60	6.9%	10.1	33.24	35.58	2.34	7.1%	8.9
12	450	42.51	45.43	2.92	6.9%	10.1	37.37	40.01	2.64	7.1%	8.9
13	500	47.21	50.46	3.25	6.9%	10.1	41.50	44.43	2.93	7.1%	8.9
14	600	56.61	60.51	3.90	6.9%	10.1	49.76	53.28	3.52	7.1%	8.9
15	700	66.01	70.56	4.55	6.9%	10.1	58.02	62.12	4.10	7.1%	8.9
16	800	75.42	80.61	5.20	6.9%	10.1	66.28	70.97	4.69	7.1%	8.9
17	900	84.82	90.66	5.85	6.9%	10.1	74.54	79.81	5.27	7.1%	8.9
18	1,000	94.22	100.72	6.50	6.9%	10.1	82.80	88.66	5.86	7.1%	8.9
19	1,500	141.23	150.97	9.75	6.9%	10.1	124.10	132.89	8.79	7.1%	8.9
20	2,000	188.24	201.23	12.99	6.9%	10.1	165.40	177.12	11.72	7.1%	8.9
21	2,500	235.25	251.49	16.24	6.9%	10.1	206.70	221.35	14.65	7.1%	8.9
22	3,000	282.26	301.75	19.49	6.9%	10.1	248.00	265.58	17.58	7.1%	8.9
23	3,500	329.27	352.01	22.74	6.9%	10.1	289.29	309.81	20.51	7.1%	8.9
24	4,000	376.28	402.26	25.99	6.9%	10.1	330.59	354.04	23.44	7.1%	8.9
25	4,500	423.29	452.52	29.24	6.9%	10.1	371.89	398.26	26.37	7.1%	8.9
26	5,000	470.30	502.78	32.48	6.9%	10.1	413.19	442.49	29.30	7.1%	8.8
27	5,500	517.31	553.04	35.73	6.9%	10.1	454.49	486.72	32.23	7.1%	8.8
28	6,000	564.32	603.30	38.98	6.9%	10.1	495.79	530.95	35.16	7.1%	8.8
29	6,500	611.33	653.56	42.23	6.9%	10.1	537.09	575.18	38.09	7.1%	8.8

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 3
Primary Interruptible Provision GI

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 31 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	7.98	8.63	0.65	8.1%	8.6	7.03	7.62	0.59	8.3%	7.6
2	110	8.76	9.48	0.71	8.2%	8.6	7.72	8.36	0.64	8.4%	7.6
3	120	9.54	10.32	0.78	8.2%	8.6	8.40	9.10	0.70	8.4%	7.6
4	130	10.32	11.16	0.84	8.2%	8.6	9.08	9.84	0.76	8.4%	7.6
5	140	11.10	12.01	0.91	8.2%	8.6	9.77	10.59	0.82	8.4%	7.6
6	150	11.88	12.85	0.97	8.2%	8.6	10.45	11.33	0.88	8.4%	7.6
7	200	15.77	17.07	1.30	8.2%	8.5	13.86	15.04	1.17	8.5%	7.5
8	250	19.66	21.28	1.62	8.3%	8.5	17.28	18.75	1.47	8.5%	7.5
9	300	23.55	25.50	1.95	8.3%	8.5	20.70	22.46	1.76	8.5%	7.5
10	350	27.44	29.72	2.27	8.3%	8.5	24.11	26.16	2.05	8.5%	7.5
11	400	31.34	33.94	2.60	8.3%	8.5	27.53	29.87	2.34	8.5%	7.5
12	450	35.23	38.15	2.92	8.3%	8.5	30.95	33.58	2.64	8.5%	7.5
13	500	39.12	42.37	3.25	8.3%	8.5	34.36	37.29	2.93	8.5%	7.5
14	600	46.90	50.80	3.90	8.3%	8.5	41.19	44.71	3.52	8.5%	7.5
15	700	54.69	59.24	4.55	8.3%	8.5	48.03	52.13	4.10	8.5%	7.4
16	800	62.47	67.67	5.20	8.3%	8.5	54.86	59.55	4.69	8.5%	7.4
17	900	70.26	76.10	5.85	8.3%	8.5	61.69	66.97	5.27	8.5%	7.4
18	1,000	78.04	84.54	6.50	8.3%	8.5	68.52	74.38	5.86	8.6%	7.4
19	1,500	116.96	126.71	9.75	8.3%	8.4	102.68	111.48	8.79	8.6%	7.4
20	2,000	155.88	168.88	12.99	8.3%	8.4	136.85	148.57	11.72	8.6%	7.4
21	2,500	194.80	211.04	16.24	8.3%	8.4	171.01	185.66	14.65	8.6%	7.4
22	3,000	233.72	253.21	19.49	8.3%	8.4	205.17	222.75	17.58	8.6%	7.4
23	3,500	272.64	295.38	22.74	8.3%	8.4	239.33	259.84	20.51	8.6%	7.4
24	4,000	311.56	337.55	25.99	8.3%	8.4	273.49	296.93	23.44	8.6%	7.4
25	4,500	350.48	379.72	29.24	8.3%	8.4	307.65	334.03	26.37	8.6%	7.4
26	5,000	389.40	421.89	32.48	8.3%	8.4	341.82	371.12	29.30	8.6%	7.4
27	5,500	428.32	464.06	35.73	8.3%	8.4	375.98	408.21	32.23	8.6%	7.4
28	6,000	467.24	506.23	38.98	8.3%	8.4	410.14	445.30	35.16	8.6%	7.4
29	6,500	506.16	548.39	42.23	8.3%	8.4	444.30	482.39	38.09	8.6%	7.4

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Time-of-Use GPTU Voltage Level 1

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	9.71	10.38	0.67	6.9%	10.4	7.61	8.19	0.58	7.6%	8.2
2	110	10.66	11.39	0.74	6.9%	10.4	8.35	8.99	0.64	7.6%	8.2
3	120	11.61	12.41	0.80	6.9%	10.3	9.09	9.78	0.69	7.6%	8.2
4	130	12.56	13.43	0.87	6.9%	10.3	9.83	10.58	0.75	7.6%	8.1
5	140	13.51	14.45	0.94	6.9%	10.3	10.57	11.38	0.81	7.7%	8.1
6	150	14.46	15.46	1.00	6.9%	10.3	11.31	12.18	0.87	7.7%	8.1
7	200	19.21	20.55	1.34	7.0%	10.3	15.02	16.17	1.16	7.7%	8.1
8	250	23.97	25.64	1.67	7.0%	10.3	18.72	20.17	1.45	7.7%	8.1
9	300	28.72	30.73	2.01	7.0%	10.2	22.42	24.16	1.74	7.7%	8.1
10	350	33.47	35.81	2.34	7.0%	10.2	26.13	28.15	2.02	7.7%	8.0
11	400	38.23	40.90	2.67	7.0%	10.2	29.83	32.15	2.31	7.8%	8.0
12	450	42.98	45.99	3.01	7.0%	10.2	33.54	36.14	2.60	7.8%	8.0
13	500	47.73	51.08	3.34	7.0%	10.2	37.24	40.13	2.89	7.8%	8.0
14	600	57.24	61.25	4.01	7.0%	10.2	44.65	48.12	3.47	7.8%	8.0
15	700	66.75	71.43	4.68	7.0%	10.2	52.06	56.11	4.05	7.8%	8.0
16	800	76.25	81.60	5.35	7.0%	10.2	59.47	64.09	4.63	7.8%	8.0
17	900	85.76	91.78	6.02	7.0%	10.2	66.87	72.08	5.21	7.8%	8.0
18	1,000	95.26	101.95	6.69	7.0%	10.2	74.28	80.07	5.78	7.8%	8.0
19	1,500	142.80	152.83	10.03	7.0%	10.2	111.32	120.00	8.68	7.8%	8.0
20	2,000	190.33	203.70	13.37	7.0%	10.2	148.37	159.93	11.57	7.8%	8.0
21	2,500	237.86	254.58	16.72	7.0%	10.2	185.41	199.87	14.46	7.8%	8.0
22	3,000	285.39	305.45	20.06	7.0%	10.2	222.45	239.80	17.35	7.8%	8.0
23	3,500	332.93	356.33	23.41	7.0%	10.2	259.49	279.73	20.24	7.8%	8.0
24	4,000	380.46	407.21	26.75	7.0%	10.2	296.53	319.67	23.13	7.8%	8.0
25	4,500	427.99	458.08	30.09	7.0%	10.2	333.57	359.60	26.03	7.8%	8.0
26	5,000	475.52	508.96	33.44	7.0%	10.2	370.62	399.53	28.92	7.8%	8.0
27	5,500	523.05	559.83	36.78	7.0%	10.2	407.66	439.47	31.81	7.8%	8.0
28	6,000	570.59	610.71	40.12	7.0%	10.2	444.70	479.40	34.70	7.8%	8.0
29	6,500	618.12	661.59	43.47	7.0%	10.2	481.74	519.33	37.59	7.8%	8.0

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Time-of-Use GPTU Voltage Level 2

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 33 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	10.17	10.84	0.67	6.6%	10.8	8.23	8.84	0.61	7.4%	8.8
2	110	11.17	11.91	0.74	6.6%	10.8	9.03	9.70	0.67	7.4%	8.8
3	120	12.17	12.97	0.80	6.6%	10.8	9.84	10.57	0.73	7.4%	8.8
4	130	13.16	14.03	0.87	6.6%	10.8	10.64	11.43	0.79	7.4%	8.8
5	140	14.16	15.10	0.94	6.6%	10.8	11.44	12.29	0.85	7.5%	8.8
6	150	15.16	16.16	1.00	6.6%	10.8	12.24	13.16	0.91	7.5%	8.8
7	200	20.15	21.48	1.34	6.6%	10.7	16.26	17.48	1.22	7.5%	8.7
8	250	25.13	26.81	1.67	6.7%	10.7	20.27	21.80	1.52	7.5%	8.7
9	300	30.12	32.13	2.01	6.7%	10.7	24.29	26.12	1.83	7.5%	8.7
10	350	35.11	37.45	2.34	6.7%	10.7	28.30	30.44	2.13	7.5%	8.7
11	400	40.09	42.77	2.68	6.7%	10.7	32.32	34.76	2.44	7.5%	8.7
12	450	45.08	48.09	3.01	6.7%	10.7	36.33	39.08	2.74	7.5%	8.7
13	500	50.07	53.41	3.35	6.7%	10.7	40.35	43.40	3.05	7.5%	8.7
14	600	60.04	64.05	4.01	6.7%	10.7	48.38	52.03	3.66	7.6%	8.7
15	700	70.01	74.69	4.68	6.7%	10.7	56.41	60.67	4.26	7.6%	8.7
16	800	79.98	85.34	5.35	6.7%	10.7	64.44	69.31	4.87	7.6%	8.7
17	900	89.96	95.98	6.02	6.7%	10.7	72.47	77.95	5.48	7.6%	8.7
18	1,000	99.93	106.62	6.69	6.7%	10.7	80.50	86.59	6.09	7.6%	8.7
19	1,500	149.80	159.83	10.04	6.7%	10.7	120.65	129.79	9.14	7.6%	8.7
20	2,000	199.66	213.04	13.38	6.7%	10.7	160.80	172.98	12.18	7.6%	8.6
21	2,500	249.53	266.25	16.73	6.7%	10.7	200.94	216.18	15.23	7.6%	8.6
22	3,000	299.39	319.46	20.07	6.7%	10.6	241.09	259.37	18.28	7.6%	8.6
23	3,500	349.26	372.67	23.42	6.7%	10.6	281.24	302.57	21.32	7.6%	8.6
24	4,000	399.12	425.89	26.76	6.7%	10.6	321.39	345.76	24.37	7.6%	8.6
25	4,500	448.99	479.10	30.11	6.7%	10.6	361.54	388.96	27.42	7.6%	8.6
26	5,000	498.85	532.31	33.46	6.7%	10.6	401.69	432.15	30.46	7.6%	8.6
27	5,500	548.72	585.52	36.80	6.7%	10.6	441.84	475.35	33.51	7.6%	8.6
28	6,000	598.58	638.73	40.15	6.7%	10.6	481.99	518.54	36.55	7.6%	8.6
29	6,500	648.45	691.94	43.49	6.7%	10.6	522.14	561.74	39.60	7.6%	8.6

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Time-of-Use GPTU Voltage Level 3

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 34 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	11.26	12.19	0.93	8.2%	12.2	9.24	10.03	0.79	8.5%	10.0
2	110	12.37	13.39	1.02	8.2%	12.2	10.15	11.02	0.87	8.6%	10.0
3	120	13.47	14.58	1.11	8.2%	12.2	11.05	12.00	0.95	8.6%	10.0
4	130	14.58	15.78	1.20	8.3%	12.1	11.96	12.98	1.03	8.6%	10.0
5	140	15.69	16.98	1.30	8.3%	12.1	12.86	13.97	1.11	8.6%	10.0
6	150	16.79	18.18	1.39	8.3%	12.1	13.77	14.95	1.19	8.6%	10.0
7	200	22.32	24.17	1.85	8.3%	12.1	18.29	19.87	1.58	8.6%	9.9
8	250	27.85	30.17	2.31	8.3%	12.1	22.81	24.78	1.98	8.7%	9.9
9	300	33.38	36.16	2.78	8.3%	12.1	27.33	29.70	2.37	8.7%	9.9
10	350	38.91	42.15	3.24	8.3%	12.0	31.85	34.62	2.77	8.7%	9.9
11	400	44.45	48.15	3.70	8.3%	12.0	36.38	39.54	3.16	8.7%	9.9
12	450	49.98	54.14	4.17	8.3%	12.0	40.90	44.45	3.56	8.7%	9.9
13	500	55.51	60.14	4.63	8.3%	12.0	45.42	49.37	3.95	8.7%	9.9
14	600	66.57	72.12	5.55	8.3%	12.0	54.46	59.20	4.74	8.7%	9.9
15	700	77.63	84.11	6.48	8.3%	12.0	63.51	69.04	5.53	8.7%	9.9
16	800	88.69	96.10	7.41	8.4%	12.0	72.55	78.87	6.32	8.7%	9.9
17	900	99.75	108.08	8.33	8.4%	12.0	81.59	88.71	7.11	8.7%	9.9
18	1,000	110.81	120.07	9.26	8.4%	12.0	90.64	98.54	7.90	8.7%	9.9
19	1,500	166.12	180.01	13.89	8.4%	12.0	135.86	147.71	11.85	8.7%	9.8
20	2,000	221.43	239.94	18.51	8.4%	12.0	181.08	196.88	15.80	8.7%	9.8
21	2,500	276.73	299.88	23.14	8.4%	12.0	226.30	246.05	19.75	8.7%	9.8
22	3,000	332.04	359.81	27.77	8.4%	12.0	271.51	295.22	23.70	8.7%	9.8
23	3,500	387.35	419.75	32.40	8.4%	12.0	316.73	344.39	27.65	8.7%	9.8
24	4,000	442.65	479.68	37.03	8.4%	12.0	361.95	393.56	31.60	8.7%	9.8
25	4,500	497.96	539.62	41.66	8.4%	12.0	407.17	442.73	35.56	8.7%	9.8
26	5,000	553.27	599.55	46.29	8.4%	12.0	452.39	491.90	39.51	8.7%	9.8
27	5,500	608.57	659.49	50.91	8.4%	12.0	497.61	541.07	43.46	8.7%	9.8
28	6,000	663.88	719.42	55.54	8.4%	12.0	542.83	590.24	47.41	8.7%	9.8
29	6,500	719.18	779.36	60.17	8.4%	12.0	577.72	639.41	61.69	10.7%	9.8

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy Intensive EIP Voltage Level 1

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 35 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	8.71	8.49	(0.22)	-2.5%	8.5	7.05	6.73	(0.32)	-4.6%	6.7
2	110	9.56	9.32	(0.24)	-2.5%	8.5	7.74	7.38	(0.36)	-4.6%	6.7
3	120	10.42	10.15	(0.26)	-2.5%	8.5	8.42	8.04	(0.39)	-4.6%	6.7
4	130	11.27	10.98	(0.29)	-2.5%	8.4	9.11	8.69	(0.42)	-4.6%	6.7
5	140	12.12	11.81	(0.31)	-2.5%	8.4	9.80	9.34	(0.45)	-4.6%	6.7
6	150	12.97	12.64	(0.33)	-2.5%	8.4	10.48	10.00	(0.48)	-4.6%	6.7
7	200	17.23	16.79	(0.44)	-2.6%	8.4	13.91	13.26	(0.65)	-4.6%	6.6
8	250	21.48	20.93	(0.55)	-2.6%	8.4	17.33	16.53	(0.81)	-4.7%	6.6
9	300	25.74	25.08	(0.66)	-2.6%	8.4	20.76	19.79	(0.97)	-4.7%	6.6
10	350	30.00	29.23	(0.77)	-2.6%	8.4	24.19	23.06	(1.13)	-4.7%	6.6
11	400	34.25	33.37	(0.88)	-2.6%	8.3	27.61	26.32	(1.29)	-4.7%	6.6
12	450	38.51	37.52	(0.99)	-2.6%	8.3	31.04	29.59	(1.45)	-4.7%	6.6
13	500	42.77	41.67	(1.10)	-2.6%	8.3	34.47	32.85	(1.62)	-4.7%	6.6
14	600	51.28	49.96	(1.32)	-2.6%	8.3	41.32	39.38	(1.94)	-4.7%	6.6
15	700	59.79	58.25	(1.54)	-2.6%	8.3	48.18	45.91	(2.26)	-4.7%	6.6
16	800	68.31	66.55	(1.76)	-2.6%	8.3	55.03	52.44	(2.59)	-4.7%	6.6
17	900	76.82	74.84	(1.98)	-2.6%	8.3	61.88	58.97	(2.91)	-4.7%	6.6
18	1,000	85.33	83.13	(2.20)	-2.6%	8.3	68.74	65.50	(3.23)	-4.7%	6.6
19	1,500	127.90	124.60	(3.30)	-2.6%	8.3	103.01	98.16	(4.85)	-4.7%	6.5
20	2,000	170.47	166.07	(4.40)	-2.6%	8.3	137.27	130.81	(6.46)	-4.7%	6.5
21	2,500	213.03	207.54	(5.50)	-2.6%	8.3	171.54	163.46	(8.08)	-4.7%	6.5
22	3,000	255.60	249.00	(6.60)	-2.6%	8.3	205.81	196.11	(9.70)	-4.7%	6.5
23	3,500	298.16	290.47	(7.69)	-2.6%	8.3	240.08	228.77	(11.31)	-4.7%	6.5
24	4,000	340.73	331.94	(8.79)	-2.6%	8.3	274.35	261.42	(12.93)	-4.7%	6.5
25	4,500	383.30	373.40	(9.89)	-2.6%	8.3	308.62	294.07	(14.55)	-4.7%	6.5
26	5,000	425.86	414.87	(10.99)	-2.6%	8.3	342.89	326.72	(16.16)	-4.7%	6.5
27	5,500	468.43	456.34	(12.09)	-2.6%	8.3	377.16	359.38	(17.78)	-4.7%	6.5
28	6,000	511.00	497.81	(13.19)	-2.6%	8.3	411.42	392.03	(19.39)	-4.7%	6.5
29	6,500	553.56	539.27	(14.29)	-2.6%	8.3	445.69	424.68	(21.01)	-4.7%	6.5

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy Intensive EIP Voltage Level 2

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 36 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	10.77	10.95	0.18	1.7%	11.0	9.16	9.24	0.08	0.8%	9.2
2	110	11.83	12.03	0.20	1.7%	10.9	10.06	10.14	0.09	0.8%	9.2
3	120	12.88	13.10	0.22	1.7%	10.9	10.95	11.05	0.09	0.9%	9.2
4	130	13.94	14.18	0.24	1.7%	10.9	11.85	11.95	0.10	0.9%	9.2
5	140	15.00	15.25	0.25	1.7%	10.9	12.74	12.85	0.11	0.9%	9.2
6	150	16.05	16.33	0.27	1.7%	10.9	13.64	13.76	0.12	0.9%	9.2
7	200	21.34	21.70	0.36	1.7%	10.9	18.12	18.28	0.16	0.9%	9.1
8	250	26.62	27.08	0.45	1.7%	10.8	22.60	22.80	0.19	0.9%	9.1
9	300	31.91	32.45	0.55	1.7%	10.8	27.08	27.31	0.23	0.9%	9.1
10	350	37.19	37.83	0.64	1.7%	10.8	31.56	31.83	0.27	0.9%	9.1
11	400	42.48	43.20	0.73	1.7%	10.8	36.04	36.35	0.31	0.9%	9.1
12	450	47.76	48.58	0.82	1.7%	10.8	40.52	40.87	0.35	0.9%	9.1
13	500	53.04	53.95	0.91	1.7%	10.8	45.00	45.39	0.39	0.9%	9.1
14	600	63.61	64.70	1.09	1.7%	10.8	53.96	54.43	0.47	0.9%	9.1
15	700	74.18	75.45	1.27	1.7%	10.8	62.92	63.47	0.54	0.9%	9.1
16	800	84.75	86.21	1.45	1.7%	10.8	71.88	72.50	0.62	0.9%	9.1
17	900	95.32	96.96	1.64	1.7%	10.8	80.84	81.54	0.70	0.9%	9.1
18	1,000	105.89	107.71	1.82	1.7%	10.8	89.80	90.58	0.78	0.9%	9.1
19	1,500	158.73	161.46	2.73	1.7%	10.8	134.61	135.77	1.17	0.9%	9.1
20	2,000	211.58	215.21	3.63	1.7%	10.8	179.41	180.96	1.55	0.9%	9.0
21	2,500	264.42	268.97	4.54	1.7%	10.8	224.21	226.15	1.94	0.9%	9.0
22	3,000	317.27	322.72	5.45	1.7%	10.8	269.01	271.34	2.33	0.9%	9.0
23	3,500	370.11	376.47	6.36	1.7%	10.8	313.81	316.53	2.72	0.9%	9.0
24	4,000	422.96	430.23	7.27	1.7%	10.8	358.62	361.72	3.11	0.9%	9.0
25	4,500	475.80	483.98	8.18	1.7%	10.8	403.42	406.91	3.50	0.9%	9.0
26	5,000	528.65	537.73	9.08	1.7%	10.8	448.22	452.10	3.88	0.9%	9.0
27	5,500	581.49	591.49	9.99	1.7%	10.8	493.02	497.29	4.27	0.9%	9.0
28	6,000	634.34	645.24	10.90	1.7%	10.8	537.82	542.48	4.66	0.9%	9.0
29	6,500	687.18	698.99	11.81	1.7%	10.8	582.63	587.67	5.05	0.9%	9.0

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy Intensive EIP Voltage Level 3

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 37 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	12.83	12.45	(0.38)	-3.0%	12.5	10.69	11.05	0.35	3.3%	11.0
2	110	14.10	13.68	(0.42)	-3.0%	12.4	11.74	12.13	0.39	3.3%	11.0
3	120	15.36	14.90	(0.46)	-3.0%	12.4	12.79	13.22	0.42	3.3%	11.0
4	130	16.63	16.13	(0.50)	-3.0%	12.4	13.84	14.30	0.46	3.3%	11.0
5	140	17.89	17.35	(0.54)	-3.0%	12.4	14.89	15.39	0.49	3.3%	11.0
6	150	19.15	18.58	(0.57)	-3.0%	12.4	15.94	16.47	0.53	3.3%	11.0
7	200	25.47	24.71	(0.76)	-3.0%	12.4	21.19	21.89	0.70	3.3%	10.9
8	250	31.79	30.83	(0.96)	-3.0%	12.3	26.44	27.32	0.88	3.3%	10.9
9	300	38.10	36.96	(1.15)	-3.0%	12.3	31.68	32.74	1.06	3.3%	10.9
10	350	44.42	43.08	(1.34)	-3.0%	12.3	36.93	38.16	1.23	3.3%	10.9
11	400	50.74	49.21	(1.53)	-3.0%	12.3	42.18	43.59	1.41	3.3%	10.9
12	450	57.06	55.34	(1.72)	-3.0%	12.3	47.43	49.01	1.59	3.3%	10.9
13	500	63.37	61.46	(1.91)	-3.0%	12.3	52.67	54.43	1.76	3.3%	10.9
14	600	76.01	73.72	(2.29)	-3.0%	12.3	63.17	65.28	2.11	3.3%	10.9
15	700	88.64	85.97	(2.68)	-3.0%	12.3	73.66	76.13	2.47	3.3%	10.9
16	800	101.28	98.22	(3.06)	-3.0%	12.3	84.16	86.98	2.82	3.4%	10.9
17	900	113.91	110.47	(3.44)	-3.0%	12.3	94.65	97.82	3.17	3.4%	10.9
18	1,000	126.55	122.73	(3.82)	-3.0%	12.3	105.14	108.67	3.52	3.4%	10.9
19	1,500	189.72	183.99	(5.73)	-3.0%	12.3	157.62	162.90	5.29	3.4%	10.9
20	2,000	252.90	245.25	(7.64)	-3.0%	12.3	210.09	217.14	7.05	3.4%	10.9
21	2,500	316.07	306.52	(9.56)	-3.0%	12.3	262.56	271.37	8.81	3.4%	10.9
22	3,000	379.25	367.78	(11.47)	-3.0%	12.3	315.03	325.61	10.57	3.4%	10.9
23	3,500	442.42	429.04	(13.38)	-3.0%	12.3	367.51	379.84	12.34	3.4%	10.9
24	4,000	505.59	490.30	(15.29)	-3.0%	12.3	419.98	434.08	14.10	3.4%	10.9
25	4,500	568.77	551.57	(17.20)	-3.0%	12.3	472.45	488.31	15.86	3.4%	10.9
26	5,000	631.94	612.83	(19.11)	-3.0%	12.3	524.92	542.55	17.62	3.4%	10.9
27	5,500	695.12	674.09	(21.02)	-3.0%	12.3	577.40	596.78	19.38	3.4%	10.9
28	6,000	758.29	735.36	(22.93)	-3.0%	12.3	629.87	651.02	21.15	3.4%	10.9
29	6,500	821.47	796.62	(24.85)	-3.0%	12.3	682.34	705.25	22.91	3.4%	10.9

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Energy-only GS
Retail Open Acess

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 38 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	250	37.72	41.54	3.82	10.1%	16.6	37.72	41.54	3.82	10.1%	16.6
2	500	55.45	63.09	7.64	13.8%	12.6	55.45	63.09	7.64	13.8%	12.6
3	750	73.17	84.63	11.46	15.7%	11.3	73.17	84.63	11.46	15.7%	11.3
4	1,000	90.90	106.18	15.28	16.8%	10.6	90.90	106.18	15.28	16.8%	10.6
5	1,500	126.35	149.26	22.92	18.1%	10.0	126.35	149.26	22.92	18.1%	10.0
6	2,000	161.80	192.35	30.55	18.9%	9.6	161.80	192.35	30.55	18.9%	9.6
7	2,500	197.25	235.44	38.19	19.4%	9.4	197.25	235.44	38.19	19.4%	9.4
8	3,000	232.70	278.53	45.83	19.7%	9.3	232.70	278.53	45.83	19.7%	9.3
9	3,500	268.15	321.62	53.47	19.9%	9.2	268.15	321.62	53.47	19.9%	9.2
10	4,000	303.60	364.71	61.11	20.1%	9.1	303.60	364.71	61.11	20.1%	9.1
11	4,500	339.05	407.79	68.75	20.3%	9.1	339.05	407.79	68.75	20.3%	9.1
12	5,000	374.50	450.88	76.38	20.4%	9.0	374.50	450.88	76.38	20.4%	9.0
13	6,000	445.40	537.06	91.66	20.6%	9.0	445.40	537.06	91.66	20.6%	9.0
14	7,000	516.30	623.23	106.94	20.7%	8.9	516.30	623.23	106.94	20.7%	8.9
15	8,000	587.20	709.41	122.21	20.8%	8.9	587.20	709.41	122.21	20.8%	8.9
16	9,000	658.10	795.59	137.49	20.9%	8.8	658.10	795.59	137.49	20.9%	8.8
17	10,000	729.00	881.76	152.77	21.0%	8.8	729.00	881.76	152.77	21.0%	8.8
18	15,000	1,083.49	1,312.64	229.15	21.1%	8.8	1,083.49	1,312.64	229.15	21.1%	8.8
19	20,000	1,437.99	1,743.53	305.54	21.2%	8.7	1,437.99	1,743.53	305.54	21.2%	8.7
20	25,000	1,792.49	2,174.41	381.92	21.3%	8.7	1,792.49	2,174.41	381.92	21.3%	8.7
21	30,000	2,146.99	2,605.29	458.30	21.3%	8.7	2,146.99	2,605.29	458.30	21.3%	8.7
22	35,000	2,501.48	3,036.17	534.69	21.4%	8.7	2,501.48	3,036.17	534.69	21.4%	8.7
23	40,000	2,855.98	3,467.05	611.07	21.4%	8.7	2,855.98	3,467.05	611.07	21.4%	8.7
24	45,000	3,210.48	3,897.93	687.46	21.4%	8.7	3,210.48	3,897.93	687.46	21.4%	8.7
25	50,000	3,564.98	4,328.82	763.84	21.4%	8.7	3,564.98	4,328.82	763.84	21.4%	8.7
26	55,000	3,919.47	4,759.70	840.22	21.4%	8.7	3,919.47	4,759.70	840.22	21.4%	8.7
27	60,000	4,273.97	5,190.58	916.61	21.4%	8.7	4,273.97	5,190.58	916.61	21.4%	8.7
28	65,000	4,628.47	5,621.46	992.99	21.5%	8.6	4,628.47	5,621.46	992.99	21.5%	8.6
29	70,000	4,982.97	6,052.34	1,069.38	21.5%	8.6	4,982.97	6,052.34	1,069.38	21.5%	8.6

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Demand GSD
Retail Open Acess

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 39 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	60.11	65.51	5.41	9.0%	13.1	60.11	65.51	5.41	9.0%	13.1
2	1,000	90.21	101.03	10.82	12.0%	10.1	90.21	101.03	10.82	12.0%	10.1
3	1,500	120.32	136.54	16.22	13.5%	9.1	120.32	136.54	16.22	13.5%	9.1
4	2,000	150.42	172.05	21.63	14.4%	8.6	150.42	172.05	21.63	14.4%	8.6
5	2,500	180.53	207.57	27.04	15.0%	8.3	180.53	207.57	27.04	15.0%	8.3
6	3,000	210.63	243.08	32.45	15.4%	8.1	210.63	243.08	32.45	15.4%	8.1
7	3,500	240.74	278.59	37.85	15.7%	8.0	240.74	278.59	37.85	15.7%	8.0
8	4,000	270.84	314.11	43.26	16.0%	7.9	270.84	314.11	43.26	16.0%	7.9
9	4,500	300.95	349.62	48.67	16.2%	7.8	300.95	349.62	48.67	16.2%	7.8
10	5,000	331.05	385.13	54.08	16.3%	7.7	331.05	385.13	54.08	16.3%	7.7
11	6,000	391.27	456.16	64.89	16.6%	7.6	391.27	456.16	64.89	16.6%	7.6
12	7,000	451.48	527.18	75.71	16.8%	7.5	451.48	527.18	75.71	16.8%	7.5
13	8,000	511.69	598.21	86.52	16.9%	7.5	511.69	598.21	86.52	16.9%	7.5
14	9,000	571.90	669.24	97.34	17.0%	7.4	571.90	669.24	97.34	17.0%	7.4
15	10,000	632.11	740.26	108.15	17.1%	7.4	632.11	740.26	108.15	17.1%	7.4
16	11,000	692.32	811.29	118.97	17.2%	7.4	692.32	811.29	118.97	17.2%	7.4
17	12,000	752.53	882.32	129.78	17.2%	7.4	752.53	882.32	129.78	17.2%	7.4
18	13,000	812.74	953.34	140.60	17.3%	7.3	812.74	953.34	140.60	17.3%	7.3
19	14,000	872.95	1,024.37	151.41	17.3%	7.3	872.95	1,024.37	151.41	17.3%	7.3
20	15,000	933.16	1,095.39	162.23	17.4%	7.3	933.16	1,095.39	162.23	17.4%	7.3
21	16,000	993.38	1,166.42	173.04	17.4%	7.3	993.38	1,166.42	173.04	17.4%	7.3
22	17,000	1,053.59	1,237.45	183.86	17.5%	7.3	1,053.59	1,237.45	183.86	17.5%	7.3
23	18,000	1,113.80	1,308.47	194.68	17.5%	7.3	1,113.80	1,308.47	194.68	17.5%	7.3
24	19,000	1,174.01	1,379.50	205.49	17.5%	7.3	1,174.01	1,379.50	205.49	17.5%	7.3
25	20,000	1,234.22	1,450.53	216.31	17.5%	7.3	1,234.22	1,450.53	216.31	17.5%	7.3
26	21,000	1,294.43	1,521.55	227.12	17.5%	7.2	1,294.43	1,521.55	227.12	17.5%	7.2
27	22,000	1,354.64	1,592.58	237.94	17.6%	7.2	1,354.64	1,592.58	237.94	17.6%	7.2
28	23,000	1,414.85	1,663.60	248.75	17.6%	7.2	1,414.85	1,663.60	248.75	17.6%	7.2
29	24,000	1,475.06	1,734.63	259.57	17.6%	7.2	1,475.06	1,734.63	259.57	17.6%	7.2

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Time-of-Use GSTU
Retail Open Acess

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 40 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	55.45	63.09	7.64	13.8%	12.6	55.45	63.09	7.64	13.8%	12.6
2	1,000	90.90	106.18	15.28	16.8%	10.6	90.90	106.18	15.28	16.8%	10.6
3	1,500	126.35	149.26	22.92	18.1%	10.0	126.35	149.26	22.92	18.1%	10.0
4	2,000	161.80	192.35	30.55	18.9%	9.6	161.80	192.35	30.55	18.9%	9.6
5	2,500	197.25	235.44	38.19	19.4%	9.4	197.25	235.44	38.19	19.4%	9.4
6	3,000	232.70	278.53	45.83	19.7%	9.3	232.70	278.53	45.83	19.7%	9.3
7	3,500	268.15	321.62	53.47	19.9%	9.2	268.15	321.62	53.47	19.9%	9.2
8	4,000	303.60	364.71	61.11	20.1%	9.1	303.60	364.71	61.11	20.1%	9.1
9	4,500	339.05	407.79	68.75	20.3%	9.1	339.05	407.79	68.75	20.3%	9.1
10	5,000	374.50	450.88	76.38	20.4%	9.0	374.50	450.88	76.38	20.4%	9.0
11	6,000	445.40	537.06	91.66	20.6%	9.0	445.40	537.06	91.66	20.6%	9.0
12	7,000	516.30	623.23	106.94	20.7%	8.9	516.30	623.23	106.94	20.7%	8.9
13	8,000	587.20	709.41	122.21	20.8%	8.9	587.20	709.41	122.21	20.8%	8.9
14	9,000	658.10	795.59	137.49	20.9%	8.8	658.10	795.59	137.49	20.9%	8.8
15	10,000	729.00	881.76	152.77	21.0%	8.8	729.00	881.76	152.77	21.0%	8.8
16	11,000	799.89	967.94	168.04	21.0%	8.8	799.89	967.94	168.04	21.0%	8.8
17	12,000	870.79	1,054.12	183.32	21.1%	8.8	870.79	1,054.12	183.32	21.1%	8.8
18	13,000	941.69	1,140.29	198.60	21.1%	8.8	941.69	1,140.29	198.60	21.1%	8.8
19	14,000	1,012.59	1,226.47	213.88	21.1%	8.8	1,012.59	1,226.47	213.88	21.1%	8.8
20	15,000	1,083.49	1,312.64	229.15	21.1%	8.8	1,083.49	1,312.64	229.15	21.1%	8.8
21	16,000	1,154.39	1,398.82	244.43	21.2%	8.7	1,154.39	1,398.82	244.43	21.2%	8.7
22	17,000	1,225.29	1,485.00	259.71	21.2%	8.7	1,225.29	1,485.00	259.71	21.2%	8.7
23	18,000	1,296.19	1,571.17	274.98	21.2%	8.7	1,296.19	1,571.17	274.98	21.2%	8.7
24	19,000	1,367.09	1,657.35	290.26	21.2%	8.7	1,367.09	1,657.35	290.26	21.2%	8.7
25	20,000	1,437.99	1,743.53	305.54	21.2%	8.7	1,437.99	1,743.53	305.54	21.2%	8.7
26	21,000	1,508.89	1,829.70	320.81	21.3%	8.7	1,508.89	1,829.70	320.81	21.3%	8.7
27	22,000	1,579.79	1,915.88	336.09	21.3%	8.7	1,579.79	1,915.88	336.09	21.3%	8.7
28	23,000	1,650.69	2,002.06	351.37	21.3%	8.7	1,650.69	2,002.06	351.37	21.3%	8.7
29	24,000	1,721.59	2,088.23	366.64	21.3%	8.7	1,721.59	2,088.23	366.64	21.3%	8.7

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP Voltage Level 1
Retail Open Acess

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 41 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	103.66	104.87	1.20	1.2%	21.0	103.66	104.87	1.20	1.2%	21.0
2	1,000	107.33	109.73	2.40	2.2%	11.0	107.33	109.73	2.40	2.2%	11.0
3	1,500	110.99	114.60	3.60	3.2%	7.6	110.99	114.60	3.60	3.2%	7.6
4	2,000	114.66	119.46	4.81	4.2%	6.0	114.66	119.46	4.81	4.2%	6.0
5	2,500	118.32	124.33	6.01	5.1%	5.0	118.32	124.33	6.01	5.1%	5.0
6	3,000	121.98	129.19	7.21	5.9%	4.3	121.98	129.19	7.21	5.9%	4.3
7	4,000	129.31	138.92	9.61	7.4%	3.5	129.31	138.92	9.61	7.4%	3.5
8	5,000	136.64	148.65	12.01	8.8%	3.0	136.64	148.65	12.01	8.8%	3.0
9	6,000	143.97	158.38	14.42	10.0%	2.6	143.97	158.38	14.42	10.0%	2.6
10	7,000	151.29	168.11	16.82	11.1%	2.4	151.29	168.11	16.82	11.1%	2.4
11	8,000	158.62	177.85	19.22	12.1%	2.2	158.62	177.85	19.22	12.1%	2.2
12	9,000	165.95	187.58	21.63	13.0%	2.1	165.95	187.58	21.63	13.0%	2.1
13	10,000	173.28	197.31	24.03	13.9%	2.0	173.28	197.31	24.03	13.9%	2.0
14	15,000	209.92	245.96	36.04	17.2%	1.6	209.92	245.96	36.04	17.2%	1.6
15	20,000	246.55	294.61	48.06	19.5%	1.5	246.55	294.61	48.06	19.5%	1.5
16	25,000	283.19	343.27	60.07	21.2%	1.4	283.19	343.27	60.07	21.2%	1.4
17	30,000	319.83	391.92	72.09	22.5%	1.3	319.83	391.92	72.09	22.5%	1.3
18	35,000	356.47	440.57	84.10	23.6%	1.3	356.47	440.57	84.10	23.6%	1.3
19	40,000	393.11	489.23	96.12	24.5%	1.2	393.11	489.23	96.12	24.5%	1.2
20	45,000	429.75	537.88	108.13	25.2%	1.2	429.75	537.88	108.13	25.2%	1.2
21	50,000	466.39	586.54	120.15	25.8%	1.2	466.39	586.54	120.15	25.8%	1.2
22	60,000	539.66	683.84	144.18	26.7%	1.1	539.66	683.84	144.18	26.7%	1.1
23	70,000	612.94	781.15	168.21	27.4%	1.1	612.94	781.15	168.21	27.4%	1.1
24	80,000	686.22	878.46	192.24	28.0%	1.1	686.22	878.46	192.24	28.0%	1.1
25	90,000	759.50	975.76	216.27	28.5%	1.1	759.50	975.76	216.27	28.5%	1.1
26	100,000	832.77	1,073.07	240.30	28.9%	1.1	832.77	1,073.07	240.30	28.9%	1.1
27	110,000	906.05	1,170.38	264.33	29.2%	1.1	906.05	1,170.38	264.33	29.2%	1.1
28	120,000	979.33	1,267.68	288.36	29.4%	1.1	979.33	1,267.68	288.36	29.4%	1.1
29	130,000	1,052.60	1,364.99	312.39	29.7%	1.0	1,052.60	1,364.99	312.39	29.7%	1.0

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP Voltage Level 2
Retail Open Acess

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	105.64	107.05	1.41	1.3%	21.4	105.64	107.05	1.41	1.3%	21.4
2	1,000	111.27	114.10	2.83	2.5%	11.4	111.27	114.10	2.83	2.5%	11.4
3	1,500	116.91	121.16	4.24	3.6%	8.1	116.91	121.16	4.24	3.6%	8.1
4	2,000	122.55	128.21	5.66	4.6%	6.4	122.55	128.21	5.66	4.6%	6.4
5	2,500	128.19	135.26	7.07	5.5%	5.4	128.19	135.26	7.07	5.5%	5.4
6	3,000	133.82	142.31	8.49	6.3%	4.7	133.82	142.31	8.49	6.3%	4.7
7	4,000	145.10	156.42	11.32	7.8%	3.9	145.10	156.42	11.32	7.8%	3.9
8	5,000	156.37	170.52	14.15	9.0%	3.4	156.37	170.52	14.15	9.0%	3.4
9	6,000	167.65	184.63	16.98	10.1%	3.1	167.65	184.63	16.98	10.1%	3.1
10	7,000	178.92	198.73	19.81	11.1%	2.8	178.92	198.73	19.81	11.1%	2.8
11	8,000	190.20	212.84	22.64	11.9%	2.7	190.20	212.84	22.64	11.9%	2.7
12	9,000	201.47	226.94	25.47	12.6%	2.5	201.47	226.94	25.47	12.6%	2.5
13	10,000	212.75	241.05	28.30	13.3%	2.4	212.75	241.05	28.30	13.3%	2.4
14	15,000	269.12	311.57	42.45	15.8%	2.1	269.12	311.57	42.45	15.8%	2.1
15	20,000	325.50	382.09	56.60	17.4%	1.9	325.50	382.09	56.60	17.4%	1.9
16	25,000	381.87	452.62	70.75	18.5%	1.8	381.87	452.62	70.75	18.5%	1.8
17	30,000	438.24	523.14	84.90	19.4%	1.7	438.24	523.14	84.90	19.4%	1.7
18	35,000	494.62	593.67	99.05	20.0%	1.7	494.62	593.67	99.05	20.0%	1.7
19	40,000	550.99	664.19	113.20	20.5%	1.7	550.99	664.19	113.20	20.5%	1.7
20	45,000	607.36	734.71	127.35	21.0%	1.6	607.36	734.71	127.35	21.0%	1.6
21	50,000	663.74	805.24	141.50	21.3%	1.6	663.74	805.24	141.50	21.3%	1.6
22	60,000	776.49	946.28	169.80	21.9%	1.6	776.49	946.28	169.80	21.9%	1.6
23	70,000	889.23	1,087.33	198.10	22.3%	1.6	889.23	1,087.33	198.10	22.3%	1.6
24	80,000	1,001.98	1,228.38	226.40	22.6%	1.5	1,001.98	1,228.38	226.40	22.6%	1.5
25	90,000	1,114.73	1,369.43	254.70	22.8%	1.5	1,114.73	1,369.43	254.70	22.8%	1.5
26	100,000	1,227.48	1,510.47	283.00	23.1%	1.5	1,227.48	1,510.47	283.00	23.1%	1.5
27	110,000	1,340.23	1,651.52	311.30	23.2%	1.5	1,340.23	1,651.52	311.30	23.2%	1.5
28	120,000	1,452.97	1,792.57	339.60	23.4%	1.5	1,452.97	1,792.57	339.60	23.4%	1.5
29	130,000	1,565.72	1,933.62	367.90	23.5%	1.5	1,565.72	1,933.62	367.90	23.5%	1.5

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy-only GP Voltage Level 3
Retail Open Acess

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 43 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	kWh	$	$	$	%	¢/kWh	$	$	$	%	¢/kWh
1	500	112.35	115.47	3.12	2.8%	23.1	112.35	115.47	3.12	2.8%	23.1
2	1,000	124.70	130.95	6.25	5.0%	13.1	124.70	130.95	6.25	5.0%	13.1
3	1,500	137.06	146.42	9.37	6.8%	9.8	137.06	146.42	9.37	6.8%	9.8
4	2,000	149.41	161.90	12.49	8.4%	8.1	149.41	161.90	12.49	8.4%	8.1
5	2,500	161.76	177.37	15.61	9.7%	7.1	161.76	177.37	15.61	9.7%	7.1
6	3,000	174.11	192.85	18.74	10.8%	6.4	174.11	192.85	18.74	10.8%	6.4
7	4,000	198.81	223.80	24.98	12.6%	5.6	198.81	223.80	24.98	12.6%	5.6
8	5,000	223.52	254.75	31.23	14.0%	5.1	223.52	254.75	31.23	14.0%	5.1
9	6,000	248.22	285.70	37.47	15.1%	4.8	248.22	285.70	37.47	15.1%	4.8
10	7,000	272.93	316.65	43.72	16.0%	4.5	272.93	316.65	43.72	16.0%	4.5
11	8,000	297.63	347.59	49.97	16.8%	4.3	297.63	347.59	49.97	16.8%	4.3
12	9,000	322.33	378.54	56.21	17.4%	4.2	322.33	378.54	56.21	17.4%	4.2
13	10,000	347.04	409.49	62.46	18.0%	4.1	347.04	409.49	62.46	18.0%	4.1
14	15,000	470.55	564.24	93.69	19.9%	3.8	470.55	564.24	93.69	19.9%	3.8
15	20,000	594.07	718.99	124.91	21.0%	3.6	594.07	718.99	124.91	21.0%	3.6
16	25,000	717.59	873.73	156.14	21.8%	3.5	717.59	873.73	156.14	21.8%	3.5
17	30,000	841.11	1,028.48	187.37	22.3%	3.4	841.11	1,028.48	187.37	22.3%	3.4
18	35,000	964.63	1,183.23	218.60	22.7%	3.4	964.63	1,183.23	218.60	22.7%	3.4
19	40,000	1,088.14	1,337.97	249.83	23.0%	3.3	1,088.14	1,337.97	249.83	23.0%	3.3
20	45,000	1,211.66	1,492.72	281.06	23.2%	3.3	1,211.66	1,492.72	281.06	23.2%	3.3
21	50,000	1,335.18	1,647.46	312.28	23.4%	3.3	1,335.18	1,647.46	312.28	23.4%	3.3
22	60,000	1,582.22	1,956.96	374.74	23.7%	3.3	1,582.22	1,956.96	374.74	23.7%	3.3
23	70,000	1,829.25	2,266.45	437.20	23.9%	3.2	1,829.25	2,266.45	437.20	23.9%	3.2
24	80,000	2,076.29	2,575.94	499.65	24.1%	3.2	2,076.29	2,575.94	499.65	24.1%	3.2
25	90,000	2,323.33	2,885.44	562.11	24.2%	3.2	2,323.33	2,885.44	562.11	24.2%	3.2
26	100,000	2,570.36	3,194.93	624.57	24.3%	3.2	2,570.36	3,194.93	624.57	24.3%	3.2
27	110,000	2,817.40	3,504.42	687.02	24.4%	3.2	2,817.40	3,504.42	687.02	24.4%	3.2
28	120,000	3,064.43	3,813.92	749.48	24.5%	3.2	3,064.43	3,813.92	749.48	24.5%	3.2
29	130,000	3,311.47	4,123.41	811.94	24.5%	3.2	3,273.90	4,123.41	849.51	25.9%	3.2

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 1
Retail Open Acess

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
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Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	0.68	0.86	0.18	26.3%	0.9	0.68	0.86	0.18	26.3%	0.9
2	110	0.73	0.93	0.20	27.0%	0.8	0.73	0.93	0.20	27.0%	0.8
3	120	0.78	0.99	0.21	27.6%	0.8	0.78	0.99	0.21	27.6%	0.8
4	130	0.83	1.06	0.23	28.2%	0.8	0.83	1.06	0.23	28.2%	0.8
5	140	0.87	1.13	0.25	28.7%	0.8	0.87	1.13	0.25	28.7%	0.8
6	150	0.92	1.19	0.27	29.1%	0.8	0.92	1.19	0.27	29.1%	0.8
7	200	1.16	1.52	0.36	30.8%	0.8	1.16	1.52	0.36	30.8%	0.8
8	250	1.41	1.85	0.45	31.9%	0.7	1.41	1.85	0.45	31.9%	0.7
9	300	1.65	2.18	0.54	32.6%	0.7	1.65	2.18	0.54	32.6%	0.7
10	350	1.89	2.51	0.63	33.2%	0.7	1.89	2.51	0.63	33.2%	0.7
11	400	2.13	2.84	0.72	33.7%	0.7	2.13	2.84	0.72	33.7%	0.7
12	450	2.37	3.18	0.81	34.0%	0.7	2.37	3.18	0.81	34.0%	0.7
13	500	2.61	3.51	0.90	34.3%	0.7	2.61	3.51	0.90	34.3%	0.7
14	600	3.09	4.17	1.07	34.8%	0.7	3.09	4.17	1.07	34.8%	0.7
15	700	3.57	4.83	1.25	35.1%	0.7	3.57	4.83	1.25	35.1%	0.7
16	800	4.06	5.49	1.43	35.3%	0.7	4.06	5.49	1.43	35.3%	0.7
17	900	4.54	6.15	1.61	35.5%	0.7	4.54	6.15	1.61	35.5%	0.7
18	1,000	5.02	6.81	1.79	35.7%	0.7	5.02	6.81	1.79	35.7%	0.7
19	1,500	7.43	10.12	2.69	36.2%	0.7	7.43	10.12	2.69	36.2%	0.7
20	2,000	9.84	13.42	3.58	36.4%	0.7	9.84	13.42	3.58	36.4%	0.7
21	2,500	12.25	16.73	4.48	36.6%	0.7	12.25	16.73	4.48	36.6%	0.7
22	3,000	14.66	20.04	5.37	36.7%	0.7	14.66	20.04	5.37	36.7%	0.7
23	3,500	17.07	23.34	6.27	36.7%	0.7	17.07	23.34	6.27	36.7%	0.7
24	4,000	19.48	26.65	7.17	36.8%	0.7	19.48	26.65	7.17	36.8%	0.7
25	4,500	21.89	29.95	8.06	36.8%	0.7	21.89	29.95	8.06	36.8%	0.7
26	5,000	24.30	33.26	8.96	36.9%	0.7	24.30	33.26	8.96	36.9%	0.7
27	5,500	26.71	36.57	9.85	36.9%	0.7	26.71	36.57	9.85	36.9%	0.7
28	6,000	29.12	39.87	10.75	36.9%	0.7	29.12	39.87	10.75	36.9%	0.7
29	6,500	31.53	43.18	11.64	36.9%	0.7	31.53	43.18	11.64	36.9%	0.7

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 2
Retail Open Acess

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 45 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	1.01	1.20	0.19	18.7%	1.2	1.01	1.20	0.19	18.7%	1.2
2	110	1.09	1.30	0.21	19.1%	1.2	1.09	1.30	0.21	19.1%	1.2
3	120	1.17	1.40	0.23	19.4%	1.2	1.17	1.40	0.23	19.4%	1.2
4	130	1.25	1.50	0.25	19.6%	1.2	1.25	1.50	0.25	19.6%	1.2
5	140	1.33	1.60	0.26	19.9%	1.1	1.33	1.60	0.26	19.9%	1.1
6	150	1.41	1.70	0.28	20.1%	1.1	1.41	1.70	0.28	20.1%	1.1
7	200	1.82	2.19	0.38	20.8%	1.1	1.82	2.19	0.38	20.8%	1.1
8	250	2.22	2.69	0.47	21.3%	1.1	2.22	2.69	0.47	21.3%	1.1
9	300	2.63	3.19	0.57	21.6%	1.1	2.63	3.19	0.57	21.6%	1.1
10	350	3.03	3.69	0.66	21.8%	1.1	3.03	3.69	0.66	21.8%	1.1
11	400	3.43	4.19	0.76	22.0%	1.0	3.43	4.19	0.76	22.0%	1.0
12	450	3.84	4.69	0.85	22.2%	1.0	3.84	4.69	0.85	22.2%	1.0
13	500	4.24	5.19	0.94	22.3%	1.0	4.24	5.19	0.94	22.3%	1.0
14	600	5.05	6.18	1.13	22.5%	1.0	5.05	6.18	1.13	22.5%	1.0
15	700	5.86	7.18	1.32	22.6%	1.0	5.86	7.18	1.32	22.6%	1.0
16	800	6.67	8.18	1.51	22.7%	1.0	6.67	8.18	1.51	22.7%	1.0
17	900	7.48	9.18	1.70	22.8%	1.0	7.48	9.18	1.70	22.8%	1.0
18	1,000	8.28	10.17	1.89	22.8%	1.0	8.28	10.17	1.89	22.8%	1.0
19	1,500	12.33	15.16	2.83	23.0%	1.0	12.33	15.16	2.83	23.0%	1.0
20	2,000	16.37	20.15	3.78	23.1%	1.0	16.37	20.15	3.78	23.1%	1.0
21	2,500	20.41	25.14	4.72	23.1%	1.0	20.41	25.14	4.72	23.1%	1.0
22	3,000	24.45	30.12	5.67	23.2%	1.0	24.45	30.12	5.67	23.2%	1.0
23	3,500	28.50	35.11	6.61	23.2%	1.0	28.50	35.11	6.61	23.2%	1.0
24	4,000	32.54	40.10	7.56	23.2%	1.0	32.54	40.10	7.56	23.2%	1.0
25	4,500	36.58	45.08	8.50	23.2%	1.0	36.58	45.08	8.50	23.2%	1.0
26	5,000	40.62	50.07	9.45	23.3%	1.0	40.62	50.07	9.45	23.3%	1.0
27	5,500	44.66	55.06	10.39	23.3%	1.0	44.66	55.06	10.39	23.3%	1.0
28	6,000	48.71	60.05	11.34	23.3%	1.0	48.71	60.05	11.34	23.3%	1.0
29	6,500	52.75	65.03	12.28	23.3%	1.0	52.75	65.03	12.28	23.3%	1.0

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 3
Retail Open Acess

Case No.: U-22070
Exhibit No.: A-16 (MCG-4)
Schedule F-4.0
Page 46 of 46
Witness: MCGrondin
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Summer (June - Sept.)					Winter (Oct. - May)				
Line	Monthly	Monthly Bills		Difference		Proposed	Monthly Bills		Difference		Proposed
No.	Use	Present	Proposed	Amount	Percent	Unit Cost	Present	Proposed	Amount	Percent	Unit Cost
	MWh	$000	$000	$000	%	¢/kWh	$000	$000	$000	%	¢/kWh
1	100	2.02	2.41	0.40	19.7%	2.4	2.02	2.41	0.40	19.7%	2.4
2	110	2.20	2.64	0.44	19.8%	2.4	2.20	2.64	0.44	19.8%	2.4
3	120	2.38	2.86	0.48	20.0%	2.4	2.38	2.86	0.48	20.0%	2.4
4	130	2.56	3.08	0.52	20.1%	2.4	2.56	3.08	0.52	20.1%	2.4
5	140	2.75	3.30	0.56	20.2%	2.4	2.75	3.30	0.56	20.2%	2.4
6	150	2.93	3.52	0.59	20.3%	2.3	2.93	3.52	0.59	20.3%	2.3
7	200	3.84	4.63	0.79	20.7%	2.3	3.84	4.63	0.79	20.7%	2.3
8	250	4.74	5.74	0.99	20.9%	2.3	4.74	5.74	0.99	20.9%	2.3
9	300	5.65	6.84	1.19	21.0%	2.3	5.65	6.84	1.19	21.0%	2.3
10	350	6.56	7.95	1.39	21.2%	2.3	6.56	7.95	1.39	21.2%	2.3
11	400	7.47	9.06	1.59	21.2%	2.3	7.47	9.06	1.59	21.2%	2.3
12	450	8.38	10.17	1.78	21.3%	2.3	8.38	10.17	1.78	21.3%	2.3
13	500	9.29	11.27	1.98	21.3%	2.3	9.29	11.27	1.98	21.3%	2.3
14	600	11.11	13.49	2.38	21.4%	2.2	11.11	13.49	2.38	21.4%	2.2
15	700	12.93	15.70	2.78	21.5%	2.2	12.93	15.70	2.78	21.5%	2.2
16	800	14.74	17.92	3.17	21.5%	2.2	14.74	17.92	3.17	21.5%	2.2
17	900	16.56	20.13	3.57	21.6%	2.2	16.56	20.13	3.57	21.6%	2.2
18	1,000	18.38	22.35	3.97	21.6%	2.2	18.38	22.35	3.97	21.6%	2.2
19	1,500	27.47	33.42	5.95	21.7%	2.2	27.47	33.42	5.95	21.7%	2.2
20	2,000	36.56	44.49	7.93	21.7%	2.2	36.56	44.49	7.93	21.7%	2.2
21	2,500	45.65	55.56	9.92	21.7%	2.2	45.65	55.56	9.92	21.7%	2.2
22	3,000	54.74	66.64	11.90	21.7%	2.2	54.74	66.64	11.90	21.7%	2.2
23	3,500	63.83	77.71	13.88	21.7%	2.2	63.83	77.71	13.88	21.7%	2.2
24	4,000	72.92	88.78	15.87	21.8%	2.2	72.92	88.78	15.87	21.8%	2.2
25	4,500	82.01	99.86	17.85	21.8%	2.2	82.01	99.86	17.85	21.8%	2.2
26	5,000	91.10	110.93	19.83	21.8%	2.2	91.10	110.93	19.83	21.8%	2.2
27	5,500	100.19	122.00	21.81	21.8%	2.2	100.19	122.00	21.81	21.8%	2.2
28	6,000	109.28	133.08	23.80	21.8%	2.2	109.28	133.08	23.80	21.8%	2.2
29	6,500	118.37	144.15	25.78	21.8%	2.2	118.37	144.15	25.78	21.8%	2.2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Rate Case (ERC) Deferral Surcharge

Case No.: U-22070
Exhibit No.: A-129 (MCG-5)
Page: 1 of 1
Witness: MCGrondin
Date: June 2026

Line No.	Description	Test-year Sales (MWh)	ERC Deferral [1] ($000)	ERC Deferral Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,513,512	$ 15,792	0.001262
	Secondary Class			
2	Energy-only GS	4,088,442	4,015	0.000982
3	Time-of-Use GSTU	101,547	100	0.000982
4	Demand GSD	2,854,081	2,129	0.000746
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	2,074	0	0.000138
6	Voltage Level 2	28,476	6	0.000194
7	Voltage Level 3	611,350	202	0.000330
	Demand GPD			
8	Voltage Level 1	1,173,597	110	0.000094
9	Voltage Level 2	1,505,108	199	0.000132
10	Voltage Level 3	2,039,025	459	0.000225
	Time-of-Use GPTU			
11	Voltage Level 1	318,251	30	0.000094
12	Voltage Level 2	399,045	53	0.000132
13	Voltage Level 3	3,628,231	816	0.000225
	Energy Intensive EIP			
14	Voltage Level 1	331,407	31	0.000094
15	Voltage Level 2	52,117	7	0.000132
16	Voltage Level 3	7,229	2	0.000225
	Lighting & Unmetered Class			
17	Metered Lighting GML	10,465	15	0.001417
18	Universal Unmetered Lighting UUL	54,935	341	0.006210
19	Unmetered GU	92,721	39	0.000419
	Self-generation Class			
20	Large Self-generation GSG-2			
21	Voltage Level 1	57,084	5	0.000094
22	Voltage Level 2	81,548	11	0.000132
23	Voltage Level 3	14,562	3	0.000225
24	Total Full Service		$ 24,364	

Line No.	Description	Test-year Sales (MWh)	ERC Deferral [1] ($000)	ERC Deferral Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001262
	Secondary Class			
2	Energy-only GS	17,123	17	0.000982
3	Time-of-Use GSTU	-	-	0.000982
4	Demand GSD	167,933	125	0.000746
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000138
6	Voltage Level 2	1,168	0	0.000194
7	Voltage Level 3	69,541	23	0.000330
	Demand GPD			
8	Voltage Level 1	1,223,357	115	0.000094
9	Voltage Level 2	1,098,601	145	0.000132
10	Voltage Level 3	1,010,718	227	0.000225
11	Total ROA Service		$ 653	
12	Total Surcharge Revenue Collected		$ 25,017	
13	Rounding		(9)	
14	Total Surcharge Revenue Target		$ 25,008	

[1] A-89 (EAD-5), line 12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 1 - 12 months ending April 30, 2027

Case No.: U-22070
Exhibit No.: A-130 (MCG-6)
Page: 1 of 2
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue [1] ($000)	(d) IRM Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,513,512	$ 12,776	0.001021
	Secondary Class			
2	Energy-only GS	4,088,442	3,246	0.000794
3	Time-of-Use GSTU	101,547	81	0.000794
4	Demand GSD	2,854,081	1,721	0.000603
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	2,074	0	0.000112
6	Voltage Level 2	28,476	4	0.000157
7	Voltage Level 3	611,350	164	0.000268
	Demand GPD			
8	Voltage Level 1	1,173,597	89	0.000076
9	Voltage Level 2	1,505,108	161	0.000107
10	Voltage Level 3	2,039,025	371	0.000182
	Time-of-Use GPTU			
11	Voltage Level 1	318,251	24	0.000076
12	Voltage Level 2	399,045	43	0.000107
13	Voltage Level 3	3,628,231	660	0.000182
	Energy Intensive EIP			
14	Voltage Level 1	331,407	25	0.000076
15	Voltage Level 2	52,117	6	0.000107
16	Voltage Level 3	7,229	1	0.000182
	Lighting & Unmetered Class			
17	Metered Lighting GML	10,465	12	0.001146
18	Universal Unmetered Lighting UUL	54,935	276	0.005025
19	Unmetered GU	92,721	31	0.000339
	Self-generation Class			
20	Large Self-generation GSG-2			
21	Voltage Level 1	57,084	4	0.000076
22	Voltage Level 2	81,548	9	0.000107
23	Voltage Level 3	14,562	3	0.000182
24	Total Full Service		$ 19,709	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue [1] ($000)	(h) IRM Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001021
	Secondary Class			
2	Energy-only GS	17,123	14	0.000794
3	Time-of-Use GSTU	-	-	0.000794
4	Demand GSD	167,933	101	0.000603
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000112
6	Voltage Level 2	1,168	0	0.000157
7	Voltage Level 3	69,541	19	0.000268
	Demand GPD			
8	Voltage Level 1	1,223,357	93	0.000076
9	Voltage Level 2	1,098,601	118	0.000107
10	Voltage Level 3	1,010,718	184	0.000182
11	Total ROA Service		$ 528	
12	Total Surcharge Revenue Collected		$ 20,237	
13	Rounding		(2)	
14	Total Surcharge Revenue Target		$ 20,235	

(1) A-79 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Investment Recovery Mechanism (IRM) Surcharge
Year 2 - 12 months ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-130 (MCG-6)
Page: 2 of 2
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Test-year Sales (MWh)	(c) IRM Revenue [1] ($000)	(d) IRM Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,513,512	$ 36,414	0.002910
	Secondary Class			
2	Energy-only GS	4,088,442	9,252	0.002263
3	Time-of-Use GSTU	101,547	230	0.002263
4	Demand GSD	2,854,081	4,906	0.001719
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	2,074	1	0.000319
6	Voltage Level 2	28,476	22	0.000763
7	Voltage Level 3	611,350	466	0.000763
	Demand GPD			
8	Voltage Level 1	1,173,597	223	0.000190
9	Voltage Level 2	1,505,108	685	0.000455
10	Voltage Level 3	2,039,025	928	0.000455
	Time-of-Use GPTU			
11	Voltage Level 1	318,251	60	0.000190
12	Voltage Level 2	399,045	182	0.000455
13	Voltage Level 3	3,628,231	1,651	0.000455
	Energy Intensive EIP			
14	Voltage Level 1	331,407	63	0.000190
15	Voltage Level 2	52,117	24	0.000455
16	Voltage Level 3	7,229	3	0.000455
	Lighting & Unmetered Class			
17	Metered Lighting GML	10,465	34	0.003265
18	Universal Unmetered Lighting UUL	54,935	786	0.014314
19	Unmetered GU	92,721	90	0.000967
	Self-generation Class			
20	Large Self-generation GSG-2			
21	Voltage Level 1	57,084	11	0.000190
22	Voltage Level 2	81,548	37	0.000455
23	Voltage Level 3	14,562	7	0.000455
24	Total Full Service		$ 56,074	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue [1] ($000)	(h) IRM Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.002910
	Secondary Class			
2	Energy-only GS	17,123	39	0.002263
3	Time-of-Use GSTU	-	-	0.002263
4	Demand GSD	167,933	289	0.001719
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000319
6	Voltage Level 2	1,168	1	0.000763
7	Voltage Level 3	69,541	53	0.000763
	Demand GPD			
8	Voltage Level 1	1,223,357	232	0.000190
9	Voltage Level 2	1,098,601	500	0.000455
10	Voltage Level 3	1,010,718	460	0.000455
11	Total ROA Service		$ 1,574	
12	Total Surcharge Revenue Collected		$ 57,648	
13	Rounding		(4)	
14	Total Surcharge Revenue Target		$ 57,644	

(1) A-79 (EAD-5)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

General Secondary Electric Heating (GSEH)

Case No.: U-22070
Exhibit No.: A-131 (MCG-7)
Page: 1 of 1
Witness: MCGrondin
Date: June 2026

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units		(d) Present Rate $/unit	(e) Present Revenue $000	(f) Proposed Rate[1][2] $/unit	(g) Proposed Revenue $000	(h) Net Increase / (Decrease) $000
	FULL SERVICE								
	Production								
	Summer (June - Sept.)								
1	Non-capacity All kWh		MWh	@		$ -	0.053253	$ -	$ -
2	Capacity All kWh	-	MWh	@		-	0.028782	-	-
	Winter (Oct. - May)								
	Non-capacity All kWh		MWh	@		-		-	-
3	First 1750 kWh	-				-	0.039938	-	-
4	Excess kWh	-				-	0.029600	-	-
	Capacity All kWh	-	MWh	@		-		-	-
5	First 1750 kWh	-				-	0.021835	-	-
6	Excess kWh	-				-	0.016186	-	-
7	Annual PSCR Factor	-	MWh	@		-	0.013710	-	-
8	Total Production					$ -		$ -	$ -
	Transmission								
	Summer (June - Sept.)								
9	All kWh	-	MWh	@		$ -	0.029462	$ -	$ -
	Winter (Oct. - May)								
10	First 1750 kWh	-				$ -	0.022350	-	-
11	Excess kWh	-	MWh	@		-	0.016567	-	-
12	Total Transmission					$ -		$ -	$ -
	Delivery								
13	System Access		Bills	@		$ -	20.00	$ -	$ -
14	Distribution	-	MWh	@		-	0.084400	-	-
	Provisions								
15	Education GEI		MWh	@		-	(0.001179)	-	-
16	Total Delivery					$ -		$ -	$ -
17	Total Full Service					$ -		$ -	$ -

(1) Proposed summer, PSCR, delivery, provision rates from Rate GS MCG-3
(2) Proposed winter rates from WP-MCG-31

EXHIBIT A-132 (MCG-8)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-133 (MCG-9)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief	))))))	Case No. U-22070

EXHIBITS

OF

QUENTIN A. GUINN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Schedule: B-5.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Facilities & Shared Services
($000)

Case No.: U-22070
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.4
Page: 1 of 3
Witness: QAGuinn
Date: June 2026

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Period* 12 Mos Ended 12/31/2026	(d) Projected Bridge Period* 4 Mos Ending 4/30/2027	(e) Projected Bridge Period* 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
1	Asset Preservation	38,132	50,029	12,876	62,905	21,932
2	Other Equipment	860	680	141	820	563
3	Total Facilities & Shared Services Capital	38,991	50,708	13,017	63,725	22,495

		Projected* 4 Mos Ending 4/30/2026	Projected* 12 Mos Ending 4/30/2027	Projected* 12 Mos Ending 4/30/2028	Projected* 28 Mos Ending 4/30/2028
4	Asset Preservation	8,206	54,699	21,932	84,837
5	Other Equipment	170	650	563	1,383
6	Total Facilities & Shared Services Capital	8,376	55,349	22,495	86,220

*The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level

Schedule: B-5.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Facilities & Shared Services
($000)

Case No.: U-22070
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.4
Page: 2 of 3
Witness: QAGuinn
Date: June 2026

Line No	Description	Historical Year 12 Mos Ended 12/31/2025	Projected Bridge Year* 12 Mos Ending 12/31/2026	Projected Bridge Year* 4 Mos Ending 4/30/2027	Projected Bridge Year* 16 Mos Ending 4/30/2027	Projected Test Year 12 Mos Ending 4/30/2028
	(a)	(b)	(c)	(d)	(e)	(f)
1	**Asset Preservation**	**38,132**	**50,029**	**12,876**	**62,905**	**21,932**
	Labor	1,338	2,978	766	3,744	1,305
	Capitalized E&S	0	0	0	0	0
	Materials	1,727	2,939	756	3,695	1,288
	Contractor	32,671	41,225	10,610	51,835	18,073
	Non-Labor Overhead	11	2,723	701	3,423	1,194
	Non-Labor Other	2,383	165	42	208	72
	Contingency	0	0	0	0	0
2	**Other Equipment**	**860**	**680**	**141**	**820**	**563**
	Labor	11	5	1	6	4
	Capitalized E&S	0	0	0	0	0
	Materials	274	401	83	484	332
	Contractor	525	222	46	268	184
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	49	51	11	61	42
	Contingency	0	0	0	0	0
3	**Total Facilities & Shared Services Capital**	**38,991**	**50,708**	**13,017**	**63,725**	**22,495**
	Labor	1,349	2,983	767	3,750	1,310
	Capitalized E&S	0	0	0	0	0
	Materials	2,001	3,340	839	4,179	1,620
	Contractor	33,197	41,447	10,656	52,103	18,257
	Non-Labor Overhead	12	2,723	701	3,423	1,194
	Non-Labor Other	2,432	216	53	269	115
	Contingency	0	0	0	0	0

*The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level

**Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

Schedule: B-5.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Facilities & Shared Services
($000)

Case No.: U-22070
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.4
Page: 3 of 3
Witness: QAGuinn
Date: June 2026

	(a)	(b)	(c)	(d)	(e)
			Projected*		
		4 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028	28 Mos Ending 4/30/2028
4	**Asset Preservation**	**8,206**	**54,699**	**21,932**	**84,837**
	Labor	488	3,256	1,305	5,050
	Capitalized E&S	0	0	0	0
	Materials	482	3,213	1,288	4,983
	Contractor	6,762	45,073	18,073	69,908
	Non-Labor Overhead	447	2,977	1,194	4,617
	Non-Labor Other	27	181	72	280
	Contingency	0	0	0	0
5	**Other Equipment**	**170**	**650**	**563**	**1,383**
	Labor	1	5	4	10
	Capitalized E&S	0	0	0	0
	Materials	100	384	332	816
	Contractor	56	213	184	452
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	13	49	42	104
	Contingency	0	0	0	0
6	**Total Facilities & Shared Services Capital**	**8,376**	**55,349**	**22,495**	**86,220**
	Labor	490	3,261	1,310	5,060
	Capitalized E&S	0	0	0	0
	Materials	582	3,597	1,620	5,800
	Contractor	6,817	45,286	18,257	70,360
	Non-Labor Overhead	447	2,977	1,194	4,617
	Non-Labor Other	40	229	115	384
	Contingency	0	0	0	0

*The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level
**Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Facilities & Shared Services
($000)

Case No.: U-22070
Exhibit No.: A-134 (QAG-2)
Page: 1 of 2
Witness: QAGuinn
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
1	**Facilities**	**14,753**	**13,366**
	Labor	3,621	3,254
	Material	-	-
	Contractor	-	-
	Non-Labor Overhead	-	-
	Non-Labor Other	11,132	10,112
2	**Real Estate**	1,938	2,800
	Labor	1,293	1,564
	Material	-	-
	Contractor	-	-
	Non-Labor Overhead	-	-
	Non-Labor Other	645	1,237
3	**Total Facilities & Shared Services O&M Expenses**	**16,690**	**16,166**
	Labor	4,913	4,817
	Material	-	-
	Contractor	-	-
	Non-Labor Overhead	-	-
	Non-Labor Other	11,777	11,349

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Facilities & Shared Services
($000)

Case No.: U-22070
Exhibit No.: A-134 (QAG-2)
Page: 2 of 2
Witness: QAGuinn
Date: June 2026

Line No.	Description	(a) Actual 12 Mos Ending 12/31/2025	(b) Inflation Applied to Projected Test Year (b) * Compounded Inflation Rate	(c) Scope/ Cost Increases Net of Productivity Gains	(d) Projected O&M 12 Mos Ending 4/30/2028 (b) + (c) + (d)
1	Facilities	14,753	921	(2,308)	13,366
2	Real Estate	1,938	121	742	2,800
3	Total Facilities & Shared Services O&M Expenses	16,690	1,042	(1,567)	16,166

Notes

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

Michigan Public Service Commission
Consumers Energy Company
Detailed List of Projected Electric Capital Expenditures
Facilities & Shared Services
(000's)

Case No: U-22070
Exhibit No: A-135 (QAG-3)
Page: 1 of 3
Witness: QAGuinn
Date: June 2026

Line No		Historical Year 12 Mos Ended 12/31/2025	Projected Bridge Period* 12 Mos Ended 12/31/2026	Projected Bridge Period* 4 Mos Ending 4/30/2027	Projected Bridge Period* 16 Mos Ending 4/30/2027	Projected Test Year* 12 Mos Ending 4/30/2028
		Electric	Electric	Electric	Electric	Electric
1	**Other Equipment**	**860**	**680**	**141**	**820**	**563**
2	Wellness Equip	31	52	-	52	-
3	Computer Equipment	2	17	1	18	5
4	Print Equipment	1	44	3	47	11
5	Supply Chain Tools & Equipment	758	522	127	649	508
6	Facilities Tools	68	44	10	54	39
7	**Emergent Repairs**	**995**	**2,314**	**305**	**2,619**	**1,631**
8	Asset Preservation - Unplanned Repair	995	2,314	305	2,619	1,631
9	**Asset Replacement**	**6,505**	**11,059**	**1,640**	**12,699**	**8,759**
10	Statewide Paving	24	3,557	484	4,041	2,586
11	Statewide Roofing	1,514	2,949	387	3,336	2,065
12	Statewide Mechanical/Electrical	4,100	3,965	669	4,634	3,571
13	Statewide Elevators	(72)	371	75	446	400
14	Marshall Roadway Paving	14	-	-	-	-
15	Furniture	925	216	25	241	136
16	**New Construction**	**12,274**	**11,986**	**4,071**	**16,057**	**638**
17	Lansing Service Center	12,222	11,986	4,071	16,057	638
18	Hastings Service Center	51	-	-	-	-
19	**Renovations**	**16,169**	**23,405**	**6,860**	**30,265**	**10,904**
20	Kalamazoo Service Center	9,430	2,204	-	2,204	-
21	Control/Dispatch Center - Grand Rapids	2,180	5,917	897	6,814	30
22	Control/Dispatch Center - Parnall	3,334	7,491	5,788	13,279	1,527
23	South Monroe Interior Renovation	432	2,540	-	2,540	-
24	OEP 5 Refresh	793	52	-	52	-
25	OEP Legal Library Renovation	-	-		-	598
26	Birch Run	-	-	-	-	4,924
27	New East Kent	-	5,200	175	5,375	3,825
28	Miscellaneous	**2,190**	**1,264**	**-**	**1,264**	**-**
29	**Total Capital**	**38,991**	**50,708**	**13,017**	**63,725**	**22,495**

*The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Facilities & Shared Services
(000's)
5 Year Historical

Case No: U-22070
Exhibit No: A-135 (QAG-3)
Page: 2 of 3
Witness: QAGuinn
Date: June 2026

	Historical Year 12 Mos Ended 12/31/2021	Historical Year 12 Mos Ended 12/31/2022	Historical Year 12 Mos Ended 12/31/2023	Historical Year 12 Mos Ended 12/31/2024	Historical Year 12 Mos Ended 12/31/2025
	Electric	Electric	Electric	Electric	Electric
Other Equipment	**797**	**862**	**403**	**357**	**860**
Wellness Equip	8	98	61	29	31
Computer Equipment	-	18	1	-	2
Print Equipment	15	-	-	37	1
Real Estate Tools & Equipment	42	18	-	-	
Supply Chain Tools & Equipment	732	727	277	212	758
Facilities Tools	-	-	63	80	68
Emergent Repairs	**3,564**	**1,523**	**1,011**	**1,010**	**995**
Asset Preservation - Unplanned Repair	3,564	1,523	1,011	1,010	995
Asset Replacement	**7,326**	**16,020**	**7,425**	**9,293**	**6,505**
Statewide Paving	2,636	3,781	2,481	928	24
Statewide Roofing	2,489	6,533	1,598	1,849	1,514
Statewide Mechanical/Electrical	975	3,846	2,538	4,027	4,100
Statewide Elevators	991	1,318	576	400	(72)
Marshall Roadway Paving	-	-	63	1,711	14
Furniture	236	541	170	376	925
New Construction	**4,574**	**3,054**	**1,790**	**2,283**	**12,274**
Lansing Service Center	90	311	1,779	2,170	12,222
Hastings Service Center	10	3	5	114	51
Hardy Headquarter Building	4,475	2,740	7	-	-
Renovations	**253**	**3,387**	**1,714**	**8,196**	**16,169**
Kalamazoo Service Center	25	182	482	4,551	9,430
Parnall Renovations (P1-3)	169	2,715	419	3	-
Jackson Dispatch		292	357	191	-
Control/Dispatch Center - Grand Rapids	-	-	-	642	2,180
Control/Dispatch Center - Parnall	-	81	-	1,764	3,334
South Monroe Interior Renovation	-	5	129	908	432
OEP 5 Refresh	-	-	-	-	793
EV Infrastructure	59	113	327	136	
Other not included in (QAG-3)	**17,759**	**3,336**	**1,991**	**158**	**2,190**
Total Electric Capital	**34,273**	**28,181**	**14,334**	**21,298**	**38,991**

Michigan Public Service Commission
Consumers Energy Company
Facilities & Shared Services

Case No: U-22070
Exhibit No: A-135 (QAG-3)
Page: 3 of 3
Witness: QAGuinn
Date: June 2026

Line No.	(a)	(b)	(c)	(d)
1	**Project Name**	**Internal Approval**	**Has a Business Case**	**Explanation**
2	Lansing Service Center	YES	YES	
3	Hastings Service Center	YES	YES	
4	Kalamazoo Service Center	YES	YES	
5	Control/Dispatch Center - Grand Rapids	YES	YES	
6	Control/Dispatch Center - Parnall	YES	YES	
7	South Monroe Interior Renovation	YES	YES	
8	OEP 5 Refresh	YES	YES	
9	OEP Legal Library Renovation	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
10	Birch Run	YES	YES	
11	New East Kent	YES	YES	
12	Statewide Paving	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
13	Statewide Roofing	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
14	Statewide Mechanical/Electrical	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
15	Statewide Elevators	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.

Asset Replacement

List of Projects and Capital Expenditures

Consumers Energy
Count on Us®

Facilities' Asset Portfolio

Site Name	Street Address	City, State, Zip
Adrian Service Center	2613 E. Maumee St.	Adrian, MI 49221
Albion Tool Hub	910 Burstein Dr	Albion, MI 49224
Alma Service Center	1325 N. Wright Ave.	Alma, MI 48801
Bad Axe Service Center	696 N. Port Crescent Rd.	Bad Axe, MI 48413
Battle Creek Service Center	311 E. Michigan Ave.	Battle Creek, MI 49014
Bay City Service Center	4141 Wilder Rd.	Bay City, MI 48706
Benzonia Service Center	2700 Benzie Highway	Benzonia, MI 49616
Big Rapids Service Center	400 Bronson Ave.	Big Rapids, MI 49307
Birch Run	11556 N DIXIE HWY	BIRCH RUN, MI 48415
Boyne City Service Center	100 N. East St.	Boyne City, MI 49712
Bronson Service Center	707 W. Chicago Rd.	Bronson, MI 49028
Cadillac Service Center	330 Chestnut St.	Cadillac, MI 49601
Caro Service Center	1028 Cleaver Rd.	Caro, MI 48723
Caro Wind Office	101 N State St	Caro, MI 48723
Clare Service Center	1 Consumers Energy Pky	Clare, MI 48617
Coldwater Service Center	505 Jonesville Rd	Coldwater, MI 49036
Consumers Innovation Center	165 W Michigan Ave	Jackson, MI 49201
Crescent Wind Farm	7001 Beck Rd	Jonesville, MI 49250
Crosswinds Wind Far	3741 W Hoppe Rd	Unionville, MI 48767
East Kent Service Center	4501 40th Street S.E.	Kentwood, MI 49512
Flint Service Center	3201 E. Court St.	Flint, MI 48506
Freedom Compressor Station	12201 Pleasant Lake Rd. Rt. 1	Manchester, MI 48158
Fremont Service Center	820 W. Main St.	Fremont, MI 49412
Gas Construction Holly	4100 E. BALDWIN RD.	HOLLY, MI 48442
Gas Construction Lansing	1530 E. JOLLY RD.	LANSING, MI 48910
Gas Construction Livonia	3250 MIDDLEBELT RD.	INKSTER, MI 48141
Gas Construction Macomb	27432 GROESBECK HWY.	ROSEVILLE, MI 48066
Gas Construction Midland	1850 BAY CITY RD.	MIDLAND, MI 48642
Gas Construction Pontiac	55 WESSEN STREET	PONTIAC, MI 48341
Gas Construction Royal Oak / Madison Heights	111 E. 12 MILE RD.	MADISON HEIGHTS, MI 48071
Gas Construction Saginaw	2119 RIVER ST.	SAGINAW, MI 48601
Gas Construction Southwest - Bellevue	6547 West Butterfield	Bellevue, MI 49021

Site Name	Street Address	City, State, Zip
Grand Rapids Service Center	4000 Clay Avenue S.W.	Grand Rapids, MI 49548
Gratiot Wind Farm	7781 SOUTH ELY HIGHWAY	MIDDLETON, MI 48856
Greenville Service Center	1100 E. Washington St.	Greenville, MI 48838
Groveland Service Center	14500 Dixie Hwy	Holly, MI 48442
Hamilton Service Center	3030 M-40 Hwy	Hamilton, MI 49419
Hart Road Facility	3247 Hart Rd	Jackson, MI 49201
Hastings Service Center	1125 Green St.	Hastings, MI 49058
Howell Grand Oaks Service Center	1000 Grand Oaks Dr	Howell, MI 48843
Investment Recovery Center	115 W. Trail St.	Jackson, MI 49201
Jackson Service Center	1955 W. Parnall Rd.	Jackson, MI 49201
Kalamazoo Service Center	2500 E. Cork St.	Kalamazoo, MI 49001
Laingsburg Training Facility	9301 Round Lake Rd	Laingsburg, MI 48848
Lake Winds Generation	4925 W Progressive Dr	Ludington, MI 49431
Lansing Service Center	530 W. Willow	Lansing, MI 48906
Livonia Service Center	11801 Farmington Rd.	Livonia, MI 48150
Ludington Service Center	5035 W Progress Drive	Ludington, MI 49431
Macomb Service Center	35350 Kelly Rd.	Clinton Township, MI 48035
Marion Compressor Station Transmission & Storage	7950 N. Partridge Rd.	Marion, MI 49665
Marshall Service Center	1220 S. Kalamazoo	Marshall, MI 49068
Meter Technology Center	1975 W. Parnall Rd.	Jackson, MI 49201
Midland Service Center	1100 Washington St.	Midland, MI 48640
Muskegon Norton Shores Service Center	700 E Sternberg Rd	Norton Shores, MI 49441
Muskegon River Compressor Station	8613 Pine Rd.	Marion, MI 49665
North Kent Service Center	679 State St	Sparta, MI 49345
Northville Compressor Station Transmission & Storage	9440 Napier Rd.	Northville, MI 48167
One Energy Plaza	One Energy Plaza	Jackson, MI 49201
Overisel Compressor Station	4131 138th Ave. Rt. 1	Hamilton, MI 49419
Owosso Service Center	1801 W. Main St.	Owosso, MI 48867
Parnall Complex	1945 W. Parnall Rd.	Jackson, MI 49201
Parnall East	1935 W. Parnall Rd.	Jackson, MI 49201
Ray Compressor Station	69333 Omo Rd.	Armada, MI 48005
Royal Oak Service Center	4600 Coolidge Highway	Royal Oak, MI 48073

Facilities Asset Portfolio (cont.)

Site Name	Street Address	City, State, Zip
Russell Leadership Center	120 Front Ave SW	Grand Rapids MI 49504
Saginaw Service Center	2400 Weiss St.	Saginaw, MI 48602
Saginaw Transmission & Storage	5131 Hackett Rd.	Saginaw, MI 48603
South Haven Conference Center	410 N. Adams Rd.	South Haven, MI 49090
South Monroe Service Center	7216 Crab Rd.	Temperance, MI 48182
St. Clair Compressor Station	10021 Marine City Hwy	IRA, MI 48203
Standish Service Center	3253 M-76	Standish, MI 48658
Tawas Service Center	2380 E Lincoln St	Tawas, MI 48730
Trail Street Lab	135 W. Trail St.	Jackson, MI 49201
Traverse City Service Center	821 Hastings St.	Traverse City, MI 49686
West Branch Service Center	4100 W M-76	West Branch, MI 48661
White Pigeon Compressor Station	68536 "A" Rd. Rt. 1	White Pigeon, MI 49099

Paving Projects

Summary List

Consumers Energy
Count on Us®

Bridge Period Paving Projects

Battle Creek Paving Project
Bay City Service Center Pavement Replacement Phase I - Sections D24 & C25
Boyne City Service Center Paving Project (Design Only in 2026)
Cadillac Service Center Paving Project - Sections 3, 4, & 5
Flint Paving Project - Section 21
Saginaw Service Center Paving Project - Section 13

Roofing Projects

Summary List

Consumers Energy
Count on Us®

Bridge Period Roofing Projects

Bay City Roofing Project
Flint Service Center Roofing Project
Grand Rapids Service Center Roofing Project

Mechanical / Electrical Projects

Summary List

Consumers Energy
Count on Us®

Bridge Period Mechanical / Electrical Projects

Alma Service Center Uninterruptible Power Supply & Power Monitoring Replacement
Alma Service Center Controls System Upgrade to BACnet Controls
Battle Creek Service Center Steam Boilers & Unit Heaters - Replace with Electric / Gas Unit Heaters
Bay City Service Center - Fans 2 & 3 and Venting Replacement
Bay City Generator Replacement & Electrical Services Upgrade
Bay City Service Center Storeroom and IPA Makeup Air Unit Replacements
Coldwater - Lighting Controls Replacement
Flint Service Center - Rooftop Unit 5 Design and Construct
Flint Service Center - Rooftop Unit 6 Design and Construct
Flint Service Center Garage Makeup Air Unit Replacement
Flint Service Center Weld Shop Renovations
Flint Service Center Air Handling Unit #6 Replacement
Flint Service Center Uniterruptible Power Supply Room A/C Unit Replacement
Fremont Garage Hose Reels & Ventilation
Grand Rapids Service Center - Aggregate Bin Boiler
Grand Rapids Service Center - Air Handling Unit Replacement
Greenville Service center Garage Exhaust Fan Replacement and Gas Detection Addition
Jackson Service Center - Lighting Replacement
Jackson Service Center Transfer Switch (Emergency) Install
Jackson Service Center Air Compressor Replacement
One Energy Plaza Controls System Upgrade to BACnet controls
One Energy Plaza Cooling Towers Replacement
Owosso Service Center Controls System Upgrade to BACnet controls
Owosso Service Center Boiler Replacement
Owosso Service Center Heating Pumps and Variable Frequency Drive Replacement
Parnall - Boilerhouse Steam Makeup Reverse Osmosis System Addition
Parnall - P22 Lighting Replacement
Parnall Air Handling Unit - A/C-21 Replacement
Parnall Air Handling Unit - A/C-9 Replacement
Parnall Cooling Tower (East) Replacement
Statewide Project - Lighting Replacement
Traverse City - Garage Makeup Air Unit and Ventilation System Replacement

Elevator Projects

Summary List

Consumers Energy
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Bridge Period Elevator Projects

Corporate Innovation Center – Freight Elevator Project
Saginaw Service Center - Hydraulic Elevator Modernization
Statewide – Elevator Maintenance

New Construction

List of Projects and Capital Expenditures

Consumers Energy
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Lansing Service Center

Project Summary

Consumers Energy
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Lansing Service Center – Health Assessment

Facility Assessment - Lansing Service Center					
Location	Lansing	Maximum Possible Points (80)	Serviciable > 48 Points	Poor < 48 Points	Good > 64 Points
Zone	MMOM				
Safety					
Compatible Use	0	5	3	2	4
Site Conditions	3	5	3	2	4
Traffic/Site Flow	1	5	3	2	4
Environmental Hazard	1	5	3	2	4
Quality					
Branding	2	5	3	2	4
Workplace Efficiency	3	5	3	2	4
Years since last major systems upgrade	0	5	3	2	4
Cost					
Facility Operating Costs	4	5	3	2	4
Non Facility Cost Impact	4	5	3	2	4
Space Optimization	3	5	3	2	4
Delivery					
Drive Time	3	5	3	2	4
Customer Response	4	5	3	2	4
Sustainability	1	5	3	2	4
Morale					
Employee Pride	2	5	3	2	4
Retention	3	5	3	2	4
Wellness	5	5	3	2	4
Total	***39***	***80***	***48***	***32***	***64***

Lansing Service Center – Health Assessment

Safety (20 Points)	Comments	Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Compatible Use	Use of property is compatible with adjoining properties and surrounding area.	Industrial zoning and use	Residential use, retail use, criminal activity	Residential zoning, high crime area	Residential zoning	Mixed Commercial / Residential zoning	Commercial zoning for Service Centers, mixed Commercial / Industrial zoning for non-Service Centers	Industrial zoning for Service Centers, Commercial zoning for non-Service Centers	Industrial zoning for Service Centers, Central Business District zoning for non-Service Centers
Site Conditions	Physical condition of site	Full utilities, good paving, fencing, drainage	No utilities, poor paving, fencing, drainage	Site not adequate to support operational requirements, located in flood plain,	Site not adequate to support operational requirements	significant upgrades, such as storm water detention, fire water, potable water, sanitary sewer, paving, etc.	Site in serviceable condition with full utilities or good condition with partial utilities	Site in good condition, full utilities	Site in good condition with undeveloped space to accommodate future growth
Traffic/Site Flow	Road network, site access drive, vehicle turning space	Close to highway, access from two roads, space for truck trailer to pull off road, one way gates	Secondary road, no truck pull off space at gate, two way gates, insufficient turning space	Unimproved road frontage / site traffic flows crossing	Non Class A road frontage / Site heavy traffic and light traffic flows crossing	with impediments, railroad tracks, intersections, etc. / Site traffic flows crossing	Class A road frontage / Site traffic flows mixed	Class A road frontage with secondary frontage / Site traffic flows separated	with secondary frontage and nearby highway access / Site traffic flows separated
Environmental Hazard	Environmental hazards	LEED certification, no environmental hazards	Former MGP site, soil contamination, abandoned underground fuel tanks, abandoned transformer storage, asbestos fire proofing, asbestos duct wrap, asbestos pipe wrap, lead paint,	Immediate hazards to employees present during normal use of site	Hazardous materials present, with reoccurring or continuous exposure hazard, former MGP site, current 201 site	Hazardous materials present in manageable form, former MGP site, current 201 site	Hazardous materials present in manageable form	No environmental impacts, hazardous materials abated or encapsulated	LEED Certified facility with no environmental impacts

Quality (15 Points)	***Employee/Customer Engagement***	Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Branding	Projects positive image to community and potential employees	Well cared for facility, curb appeal, neat landscaping, coordinated site signage	Dilapidated facility, dated appearance, overgrown landscaping, mismatched site signage	damaged or deteriorated structures, landscape materials overgrown or absent, failed pavement, etc.	Structures deteriorated, landscape materials overgrown or absent, failing paving, no signage	Structures poorly maintained, landscape materials overgrown or absent, poor signage	for, landscape materials in serviceable condition, uncoordinated signage	Structures well cared for, landscape materials in good condition, coordinated signage	New facility, landscape materials in good condition, coordinated signage
Workplace Efficiency	Space is fully utilized	Space provided for all operational functions, space size meets needs, proper inventory stored	Space not provided for all operational functions, space oversized, space not fully utilized, unused materials (junk) stored	Space inadequate for intended occupancy	Hard wall offices, empty or vacant spaces	Hard wall offices, fully utilized	Mix of hard wall offices and systems furniture, fully utilized	Modular systems furniture, fully utilized	Flexible, open and collaborative workspaces, modular systems furniture, fully utilized
Years since last major systems upgrade	Condition of facility is code compliant, building systems are within normal operational life cycle and supports working environment	New construction or recently completed full renovation	Building old and unrenovated or only minimal or partial renovation work completed	initial construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade

Lansing Service Center – Health Assessment

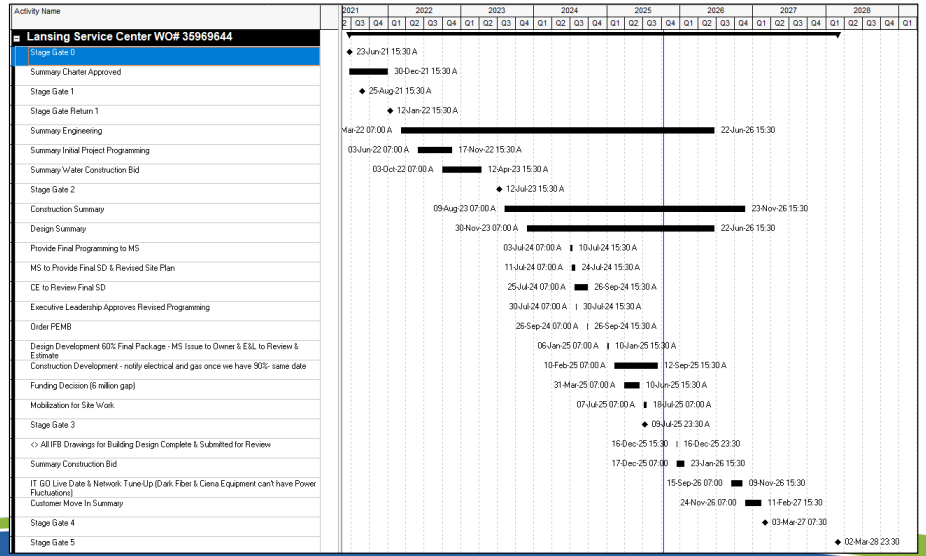
Cost (15 Points)		Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Facility Operating Costs	O&M costs to operate and maintain facility	Cost per square foot for facility less than statewide average cost per square foot ($5.31)	Cost per square foot for facility more than statewide average cost per square foot ($5.31)	costs greater than $10.00 per square foot	costs between $8.00 to $10.00 per square foot	costs between $7.25 to $7.99 per square foot	costs between $7.00 to $7.24 per square foot	costs between $5.75 to $6.99 per square foot	Combined operating costs less than $5.75 per square foot
Non Facility Cost Impact	O&M cost impacts to operations	Building correct size, centrally located within customer base area, able to accommodate necessary materials, able to maneuver onsite	Building too large, eccentrically located within customer base area, unable to accommodate necessary materials, difficult to maneuver onsite	Building eccentrically located within service territory, inadequate space	Building eccentrically located within service territory, underutilized space	Building eccentrically located within service territory	Building centrally located within service territory	Building accommodates operational needs, centrally located within service territory	Building accommodates operational need, space utilized efficiently, centrally located within service territory
Space Optimization	Reduce excess square footage	Space fully utilized, space utilized efficiently	Space under utilized, space utilized inefficiently, indoor parking area	Building vacant	Building partially occupied or partially vacant	Building occupied inefficiently, includes IPA	Building fully occupied, includes IPA	Building fully occupied, no IPA	occupied, no IPA, includes cold storage

Delivery (15 Points)	Customer Service	Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Drive Time	Service territory area of proper size	Centrally located within service area(s), drive time balanced across territory and within targeted limits	Eccentrically located within service area(s), drive time unbalanced across territory and/or exceeds targeted limits	service territory and size of service territory allows drive time >1:20 Gas and >1:30 Electric	service territory and size of service territory allows drive time < 1:20 Gas and <1:30 Electric	service territory and size of service territory allows drive time < 1:10 Gas and <1:15 Electric	service territory and size of service territory allows drive time < 1:00 Gas and <1:00 Electric	service territory and size of service territory allows drive time < 0:50 Gas and <0:45 Electric	service territory and size of service territory allows drive time < 0:40 Gas and <0:30 Electric
Customer Response	Meets needs of customers	Customer response time metrics fall below targets	Customer response times exceed targets	response times meet target <90% of time, Electric CAIDI >215 minutes	response times meet target >90% of time, Electric CAIDI <215 minutes	response times meet target >95% of time, Electric CAIDI <195 minutes	response times meet target >97% of time, Electric CAIDI <180 minutes	response times meet target >98% of time, Electric CAIDI <165 minutes	response times meet target >99% of time, Electric CAIDI <150 minutes
Sustainability	Facility incroprates reduced energy utilization and minimizes environmental impact	Facility constructed in accordance with recent Energy Codes, includes onsite stormwater treatment, Green building certification	Facility constructed with no insulation, utilizes enegy intensive equipment, no onsite storm water treatment	Minimal roofing insulation	Upgraded roofing insulation	Upgraded roofing insulation and windows	Upgraded roofing insulation, windows and building envelope	insulation, windows, and building envelope with onsite storm water treatment	LEED Certified (or higher LEED rated) facility

Lansing Service Center – Health Assessment

Morale (15 Points)				Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Employee Wellness		Pro	Con						
Employee Pride	Employees are engaged	Employee engagement scores > company average	Employee engagement scores < company average	Deteriorated facility	Deteriorated or dated facility with limited amenities	Dated facility with minimal amenities	Dated facility with full amenities and onsite parking	Modern facility with full amenities	Modern facility with full amenities, onsite parking
Retention	Facilities located in a desirable area, space is attractive to Millennials and supports millennial work styles	Downtown location, local amenities available, space supports varied work styles	Remote location, few local amenities, fixed work space	Remote location, no local amenities	some amenities available within 20 minutes driving distance	Remote location, amenities available within 20 minutes driving distance	Remote location, amenities available within 15 minutes driving distance	Diverse location, amenities available within 10 minutes driving distance	Diverse location, amenities available within walking distance
Wellness	Wellness facilities	Wellness room, space for trainer, drinking fountain, shower facilities nearby, space for wellness classes, well maintained exercise equipment, mirrors, lockers	Wellness room combined with non-compatible uses (i.e.: conference room), aged exercise equipment, poorly maintained exercise equipment, remote shower facilities	No shower, drinking fountain, Wellness or Nursing Mother Room, no additional space available	Shower and drinking fountain, no Wellness or Nursing Mother Room, no additional space available	Wellness Room or Nursing Mother Room, shower and drinking fountain, no additional space available	Nursing Mother Room, shower and drinking fountain, with space available to add Wellness or NMR	Wellness Room and Nursing Mother room, shower and drinking fountain, with space available for Trainer	Wellness room, Trainer room, Nursing Mother Room, shower and drinking fountain nearby

Lansing Service Center – Project Schedule



Lansing Service Center – Project Expenditures v. Rate Case U-20963 Allowance

Lansing Service Center Project Spend ($)	2019 Total	2020 Total	2021 Total	2022 Total	2023 Total	2024 Total	2025 Total	Total Project Spend Thru 12/31/25	Lansing Service Center Case No. U20963 Allowance	Variance - Total Lansing Project Spend Thru 12/31/25 to U20963 Allowance	(%) of U20963 Allowance Spent Thru 12/31/25
Electric Allocation	16,939	1,006,192	89,633	310,675	1,778,681	2,169,659	12,222,300	17,594,079	15,724,000	1,870,079	112%
Gas Allocation	14,290	849,566	75,955	261,575	1,500,597	1,817,219	10,261,696	14,780,898	13,276,000	1,504,898	111%
Total	31,229	1,855,758	165,588	572,250	3,279,278	3,986,878	22,483,996	32,374,977	29,000,000	3,374,977	112%

Lansing Service Center – Building Rendering



Lansing Service Center – Alternatives Matrix

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Alternative Scenario Evaluation Matrix - Lansing Service Center Major Systems Upgrade

	Weight	Build on New Site Score	Renov. Existing Score	Do Nothing Score	Score	COMMENTS
Section 1 - Affordable (50%)						
Operating cost per square foot below statewide average	40%	4.0	3.0	2.0		Current facility operating cost for Lansing is $6.97 per square foot, versus statewide average operating cost of $5.31 per square foot
Construction cost	10%	1.0	4.0	5.0		
Section 1 - Scenario Average Weighted Score Total (Best = 5):		1.7	1.6	1.3	0.0	
Section 2 - Safe (25%)						
Hazardous Material Abatement (asbestos, lead paint)	5.0%	4.0	3.0	1.0		
Site located outside high crime area	5.0%	4.0	1.0	1.0		
Pedestrian traffic route separated from truck traffic route	2.5%	4.0	1.0	1.0		
Site located outside defined FEMA 100 year flood elevation	10.0%	4.0	1.0	1.0		Current location is 3' below FEMA 100 year flood elev.
Site soils not impacted by previous use (Manufactured Gas Plant)	2.5%	4.0	1.0	1.0		Current location is former Manufactured Gas Plant site
Section 2 - Scenario Average Score Total (Best = 5):		1.0	0.4	0.3	0.0	
Section 3 - Reliable (17.5%)						
Overall score above 72 as measured by Facilites Scorecard	2.5%	4.0	3.0	1.0		Current overall facility score for Lansing is 39
Building size matches operational needs	5.0%	4.0	2.0	2.0		Building fully occupied currently (pre COVID-19)
Improve CAIDI Score > 3%	4.0%	4.0	1.0	1.0		
On Premise start times improved by 5 to 10 minutes	5.0%	4.0	2.0	1.0		Improved material flow and vehicle loading
Drive through vehicle repair bays	2.5%	4.0	2.0	2.0		Improved vehicle repair time, reduced vehicle damage
Section 3 - Scenario Weighted Score Total (Best = 5):		0.6	0.3	0.2	0.0	
Section 4 - Clean (7.5%)						
LEED V4.1 Certification	2.5%	4.0	3.0	1.0		
Stormwater detention and treatment	2.5%	4.0	1.0	1.0		Stormwater currently direct discharge to Grand River
Onsite solar power generation	1.0%	4.0	1.0	1.0		
Section 3 - Scenario Weighted Score Total (Best = 5):		0.2	0.1	0.1	0.0	
TOTAL WEIGHTED VALUE SCORE: (BEST = 5)	100%	3.5	2.4	1.8	0.0	

Lansing Service Center – Alternatives Matrix

Safe
Hazardous Material Abatement (asbestos, lead paint)
Site located outside high crime area
Pedestrian traffic route separated from truck traffic route
Site located outside defined FEMA 100 year flood elevation
Site soils not impacted by previous use
Affordable
Operating cost per square foot below statewide average
Construction cost
Reliable
Overall score above 72 as measured by Facilites Scorecard
Building size matches operational needs
Improve CAIDI Score > 3%
On Premise start times improved by 5 to 10 minutes
Drive through vehicle repair bays
Clean
LEED V4.1 Certification
Stormwater detention and treatment
Onsite solar power generation
Non-Monetary Considerations
Other Risks & Barriers
Regulatory
Technical/Engineering
Aesthetics
People
Process
Technology
Customer Requirements
Real Estate
Municipality Requirements

New Lansing Service Center – Potential Locations

Property Details	Site A	Site B	Site C
Site Address	6964 N. Canal Rd. Dimondale, MI 48821	401 N. Verlinden Ave. Lansing, MI 48915	S. Waverly Rd & W. Miller Rd. Lansing, MI 48911
County	Eaton	Ingham	Ingham
Municipality	Windsor Township	City of Lansing	City of Lansing
Acreage	77.67	57	50

New Lansing Service Center – Potential Locations

Site Characteristics	Site A	Site B	Site C
Site Address	6964 N. Canal Rd. Dimondale, MI 48821	401 N. Verlinden Ave. Lansing, MI 48915	S. Waverly Rd. & W. Miller Rd. Lansing, MI 48911
Internal CE Security Assessment	Low Risk	High Risk	Medium Risk
Distance to Highways	Less than 1 mile to I-96	¼ Mile from M43; 2 miles to I-496	1.5 miles to I-96
Zoning	M1 Industrial	Industrial	Residential
3 Phase	Yes	Yes	No
Natural Gas	Yes	Yes	Yes
Water	No; water main extension pending	Yes	Yes
Sewer	Yes	Yes	Yes
Fiber	No	No	No
Wetlands Identified	Yes; 60 usable acres	No; 57 usable acres	Yes; 40 usable acres
Known Environmental Contamination	No	Yes	No

New Lansing Service Center – Potential Locations – Gas / Electric Customer Response Time Comparisons

Electric work order x minutes
Number of Work Orders and Time

Verlinden Site Option	Electric		
10 minutes	17,984	179,840	
20 minutes	63,792	1,275,840	
30 minutes	15,949	478,470	
40 minutes	972	38,880	
50 minutes			
Total	98,697	1,973,030	Best Electric but worst Gas
Waverly Site Option	**Electric**		
10 minutes	7,505	75,050	
20 minutes	52,207	1,044,140	
30 minutes	31,058	931,740	
40 minutes	7,841	313,640	
50 minutes	86	4,300	
Total	98,697	2,368,870	Worst Electric but best Gas
Canal Site Option	**Electric**		
10 minutes	8,464	84,640	
20 minutes	56,349	1,126,980	
30 minutes	28,126	843,780	
40 minutes	5,742	229,680	
50 minutes	16	800	
Total	98,697	2,285,880	Mid for both Electric and Gas

Gas work order x minutes
Number of Work Orders and Time

Verlinden Site Option	Gas		
10 minutes	41,742	417,420	
20 minutes	62,020	1,240,400	
30 minutes	22,865	685,950	
40 minutes	1,939	77,560	
50 minutes			
Total	128,566	2,421,330	Worst Gas but best Electric
Waverly Site Option	**Gas**		
10 minutes	26,982	269,820	
20 minutes	77,463	1,549,260	
30 minutes	19,380	581,400	
40 minutes	4,741	189,640	
50 minutes			
Total	128,566	2,590,120	Best Gas but worst Electric
Canal Site Option	**Gas**		
10 minutes	21,801	218,010	
20 minutes	85,674	1,713,480	
30 minutes	17,453	523,590	
40 minutes	3,638	145,520	
50 minutes			
Total	128,566	2,600,600	Mid for both Gas and Electric

New Lansing Service Center – Potential Locations within City of Lansing

401 N. Verlinden Ave. Lansing, MI 48915

Positives:
- Low purchase price
- Potential tax incentives available
- Utilities available

Limitations:
- Environmental concerns
- Unknown abandon utilities and tunnels under surface
- LBWL substation on site along with HVD line but unable to serve ourselves with electric
- Fiber would need to be ran to site
- Medium-risk security assessment needed

S. Waverly Rd. & W. Miller Rd. Lansing, MI 48911

Positives:
- Potential assistance with site preparation
- Potential assistance with demo of asbestos

Limitations:
- Wetlands and possibly not enough usable property
- Potentially unable to have a drive on S. Waverly due to hill and high speeds coming northbound on Waverly - both drives would have to be off of W. Miller Rd
- Length of time to potentially acquire site
- Demo of houses with asbestos
- Probably unable to serve ourselves with electric
- Fiber is currently some distance away – would need to be ran to site
- Currently zoned residential and would need to be rezoned to light industrial
- Medium-risk security assessment needed
- Unknown purchase price

New Lansing Service Center – Potential Locations within City of Lansing

South of Grand River, Ave.

Positives:

- Utilities available (Water & Sewer)

Limitations:

- Fuel station across the street
- Possible wetlands
- Further north
- Lots of traffic on road

*No other data was collected regarding this location





New Lansing Service Center Potential Location

401 N. Verlinden Ave. Lansing - Site Characteristics

57 acres

Response Time:	• 87% of reported outages are reached in 30 minutes timeframe • 100% of reported outages are reached within 45 minutes
Ease of Travel:	CE Operations: • Difficulty with turning and maneuvering trucks and trailers through city streets and blocks • Travel impediment due to foot and bike traffic, CATA bus stops, railroad crossing and street parking in residential areas • Difficult to access highways through residential areas: 2 miles to I-496
Security:	• **CE Security Risk Assessment Rating – HIGH** • Crimes occurring within 1-mile radius of parcel within 12/26/19-01/23/20: Assault – 15; Weapon Offenses – 6; Larceny – 6; Vandalism – 4; Burglary – 4; Motor Vehicle Theft – 3; Robbery – 1 • 74 sex offenders in registry within 1-mile radius
Wetlands identified:	• No identified wetlands on the parcel
Environmental concerns:	• Significant concern regarding existing contamination and abandoned underground utility facilities on the property. Further due diligence would be required if site is selected to evaluate impact to service center construction and operations.

New Lansing Service Center Potential Location

S. Waverly & W. Miller Rd, Lansing - Site Characteristics

33 usable acres

Response Time:	• 88% of reported outages are reached in the 30 minutes • 100% of reported outages are reached within 50 minutes
Ease of Travel:	CE Operations: • Difficulty with turning and maneuvering trucks and trailers through city streets and blocks • Travel impediment due to foot and bike traffic, CATA bus stops and street parking in residential areas • Difficult to access highways through residential areas: 1.5 miles to I-96
Security:	• **CE Security Risk Assessment Rating – MEDIUM** • Crimes occurring within 1-mile radius of parcel within 12/26/19-01/23/20: Assault – 6; Vandalism – 1; Larceny – 1; Motor Vehicle Theft – 1 • 16 sex offenders in registry within 1-mile radius
Wetlands identified:	• The State's National Wetland Inventory map indicates 17 acres of regulated wetlands of the 50-acre parcel • CE would not be able to use 17 acres without costly wetland mitigation. Would limit or possibly eliminate future expansion on site.
Environmental concerns:	• LEAP reports asbestos abatement needed prior to demolition of existing houses on parcel • CE Environmental reports existing contaminated site on the adjacent property to the east



New Lansing Service Center Potential Location

6964 N. Canal Rd, Dimondale - Site Characteristics

60 usable acres

Response Time:	• 91% of reported outages are reached in the 30 minute timeframe • 100% of reported outages are reached within 45 minutes
Ease of Travel:	CE Operations: • Located in the industrial area of Windsor Commerce Parkway. Roads and intersections provide for wider turns for maneuvering trucks and trailers • Access to highways through commercial areas: 0.75 miles to I-96; 1.35 miles to I-69 • Limited foot and bike traffic and no parking on roads
Security:	• **CE Security Risk Assessment Rating – LOW** • Crimes occurring within 1-mile radius of parcel within 12/26/19-01/23/20: Assault – 0 • 4 sex offenders in registry within 1-mile radius • High police presence due to Michigan State Police within 0.6 miles from parcel
Wetlands identified:	• The State's National Wetland Inventory map indicates 7.29 acres of regulated wetlands on the 77.67-acre parcel • Property size allows for CE use to be designed to avoid wetland areas and allow for future expansion.
Environmental concerns:	• No known environmental concerns

New Lansing Service Center – Electric Benefits

New Lansing Service Center - Electric Customer Benefits

Electric work order x minutes
Number of Work Orders x Travel Time

Canal - New Site	Electric	WO x Min.
10 minutes	8,464	84,640
20 minutes	56,349	1,126,980
30 minutes	28,126	843,780
40 minutes	5,742	229,680
50 minutes	16	800
Total	98,697	2,285,880

Willow - Current Site	Electric	WO x Min.
10 minutes	2,142	21,420
20 minutes	58,784	1,175,680
30 minutes	31,496	944,880
40 minutes	6,239	249,560
50 minutes	36	1,800
Total	98,697	2,393,340

2018 Electric Outages	50,135	Customers
2019 Electric Outages	56,670	Customers
Total Electric Outages	106,805	Customers
Avg Annual Outages	53,403	Customers

Difference:	107,460	Minutes reduction in travel time to customer sites compared to Willow Road
	4.5%	Reduction in travel time to customer sites compared to Willow Road
Cost Savings:	$185,906	Productivity recaptured annually based on $3.46 per minute per employee

Electric CAIDI Improvement:	53,730	Annual reduction in travel minutes
	4,478	Monthly reduction in travel minutes

New Lansing Service Center – Gas Benefits

New Lansing Service Center - Gas Customer Benefits

Gas work order x minutes
Number of Work Orders x Travel Time

Canal - New Site	Gas	WO x Min.
10 minutes	21,801	218,010
20 minutes	85,674	1,713,480
30 minutes	17,453	523,590
40 minutes	3,638	145,520
50 minutes		
Total	128,566	2,600,600

Willow - Current Site	Gas	Adjust.
10 minutes	25,726	257,260
20 minutes	62,260	1,245,200
30 minutes	30,560	916,800
40 minutes	9,489	379,560
50 minutes	531	26,550
Total	128,566	2,825,370

Difference:	**224,770**	**Minutes reduction in travel time to customer sites compared to Willow Road**
	8.0%	**Reduction in travel time to customer sites compared to Willow Road**
Cost Savings:	**$309,059**	**Productivity recaptured annually based on $2.75 per minute per employee**

Gas Response Time Improvement: 224,770

Hastings Service Center

Project Summary

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Hastings Service Center – Health Assessment

Facility Assessment - Hastings Service Center					
Location	Hastings	Maximum Possible Points (80)	Serviceable > 48 Points	Poor < 48 Points	Good > 64 Points
Zone	SWOM				
Safety					
Compatible Use	4	5	3	2	4
Site Conditions	4	5	3	2	4
Traffic/Site Flow	2	5	3	2	4
Environmental Hazard	3	5	3	2	4
Quality					
Branding	3	5	3	2	4
Workplace Efficiency	3	5	3	2	4
Years since last major systems upgrade	1	5	3	2	4
Cost					
Facility Operating Costs	0	5	3	2	4
Non Facility Cost Impact	4	5	3	2	4
Space Optimization	2	5	3	2	4
Delivery					
Drive Time	4	5	3	2	4
Customer Response	3	5	3	2	4
Sustainability	3	5	3	2	4
Morale					
Employee Pride	1	5	3	2	4
Retention	3	5	3	2	4
Wellness	1	5	3	2	4
Total	***41***	***80***	***48***	***32***	***64***

Hastings Service Center – Health Assessment Scoring Criteria

Safety (20 Points)	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Compatible Use	Residential zoning, high crime area	Residential zoning	Mixed Commercial / Residential zoning	Commercial zoning for Service Centers; mixed Commercial / Industrial zoning for non-Service Centers	Mixed Commercial / Industrial zoning for Service Centers, Commercial zoning for non-Service Centers	Industrial zoning for Service Centers, Central Business District zoning for non-Service Centers
Site Conditions	Site not adequate to support operational requirements, located in flood plain,	Site not adequate to support operational requirements	significant upgrades, such as storm water detention, fire water, portable water, sanitary sewer, paving, etc.,	Site in serviceable condition with full utilities or good condition with partial utilities	Site in good condition, full utilities	Site in good condition with undeveloped space to accommodate future growth
Traffic/Site Flow	Unimproved road frontage / site traffic flow s crossing	Non Class A road frontage / Site heavy traffic and slight traffic flow s crossing	with impediments, railroad tracks, intersections, etc. / Site traffic flow s crossing	Class A road frontage / Site traffic flow s mixed	Class A road frontage with secondary frontage / Site traffic flow s separated	Class A road frontage with secondary frontage and nearby highway access / Site traffic flow s separated
Environmental Hazard	Immediate hazards to employees present during normal use of site	Hazardous materials present, with reoccurring or continuous exposure hazard, former MGP site, current ZO1 site	Hazardous materials present in manageable form, former MGP site, current ZO1 site	Hazardous materials present in manageable form	No environmental impacts, hazardous materials abated or encapsulated	LEED Certified facility with no environmental impacts
Quality (15 Points)	**Score 0**	**Score 1**	**Score 2**	**Score 3**	**Score 4**	**Score 5**
Branding	damaged or deteriorated structures, landscape materials overgrown or absent, failed pavement, etc.	Structures deteriorated, landscape materials overgrown or absent, failing paving, no signage	Structures poorly maintained, landscape materials overgrown or absent, poor signage	Structures well cared for, landscape materials in serviceable condition, uncoordinated signage	Structures well cared for, landscape materials in good condition, coordinated signage	New facility, landscape materials in good condition, coordinated signage
Workplace Efficiency	Space inadequate for intended occupancy	Hard wall offices, empty or vacant spaces	Hard wall offices, fully utilized	1%+ of hard wall offices and systems furniture, fully utilized	Modular systems furniture, fully utilized	Flexible, open and collaborative workspaces, modular systems furniture, fully utilized
Years since last major systems upg	construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade	0-10 years since initial construction or last major systems upgrade
Cost (15 Points)	**Score 0**	**Score 1**	**Score 2**	**Score 3**	**Score 4**	**Score 5**
Facility Operating Costs	costs greater than $10.00 per square foot	costs between $8.00 to $10.00 per square foot	costs between $7.25 to $7.99 per square foot	costs between $7.00 to $7.24 per square foot	costs between $5.75 to $6.99 per square foot	Combined operating costs less than $5.75 per square foot
Non Facility Cost Impact	Building eccentrically located within service territory, inadequate space	Building eccentrically located within service territory, underutilized space	Building eccentrically located within service territory	Building centrally located within service territory	Building accommodates operational needs, centrally located within service territory	Building accommodates operational need, space utilized efficiently, centrally located within service territory
Space Optimization	Building vacant	Building partially occupied or partially vacant	Building occupied inefficiently, includes IPA	Building fully occupied, includes IPA	Building fully occupied, no IPA	Building fully occupied, no IPA, includes cold storage

Delivery (15 Points)						
Drive Time	service territory and size of service territory allows drive time >1.20 Gas and >1.30 Electric	service territory and size of service territory allows drive time < 1.20 Gas and <1.30 Electric	Location within service territory and size of service territory allows drive time < 1.10 Gas and <1.15 Electric	service territory and size of service territory allows drive time < 1.00 Gas and <1.00 Electric	service territory and size of service territory allows drive time < 0.50 Gas and <0.45 Electric	service territory and size of service territory allows drive time < 0.40 Gas and <0.30 Electric
Customer Response	response times meet target <90% of time, Electric CAIDI >215 minutes	response times meet target >90% of time, Electric CAIDI <215 minutes	response times meet target >95% of time, Electric CAIDI <195 minutes	response times meet target >97% of time, Electric CAIDI <180 minutes	response times meet target >98% of time, Electric CAIDI <165 minutes	response times meet target >99% of time, Electric CAIDI <150 minutes
Sustainability	Minimal roofing insulation	Upgraded roofing insulation	Upgraded roofing insulation and windows	Upgraded roofing insulation, windows and building envelope	Upgraded roofing insulation, windows, and building envelope with onsite storm water treatment	LEED Certified (or higher LEED rated) facility
Morale (15 Points)	**Score 0**	**Score 1**	**Score 2**	**Score 3**	**Score 4**	**Score 5**
Employee Pride	Deteriorated facility	Deteriorated or dated facility with limited amenities	Dated facility with minimal amenities	Dated facility with full amenities and onsite parking	Modern facility with full amenities	Modern facility with full amenities, onsite parking
Retention	Remote location, no local amenities	some amenities available within 20 minutes driving distance	Remote location, amenities available within 20 minutes driving distance	Remote location, amenities available within 15 minutes driving distance	Diverse location, amenities available within 10 minutes driving distance	Diverse location, amenities available within walking distance
Wellness	No shower, drinking fountain, Wellness or Nursing Mother Room, no additional space available	Shower and drinking fountain, no Wellness or Nursing Mother Room, no additional space available	Wellness Room or Nursing Mother Room, shower and drinking fountain, no additional space available	Wellness Room or Nursing Mother Room, shower and drinking fountain, with space available to add Wellness or NMR	Wellness Room and Nursing Mother room, shower and drinking fountain, with space available for Trainer	Wellness room, Trainer room, Nursing Mother Room, shower and drinking fountain nearby

Hastings Service Center – Alternatives Matrix

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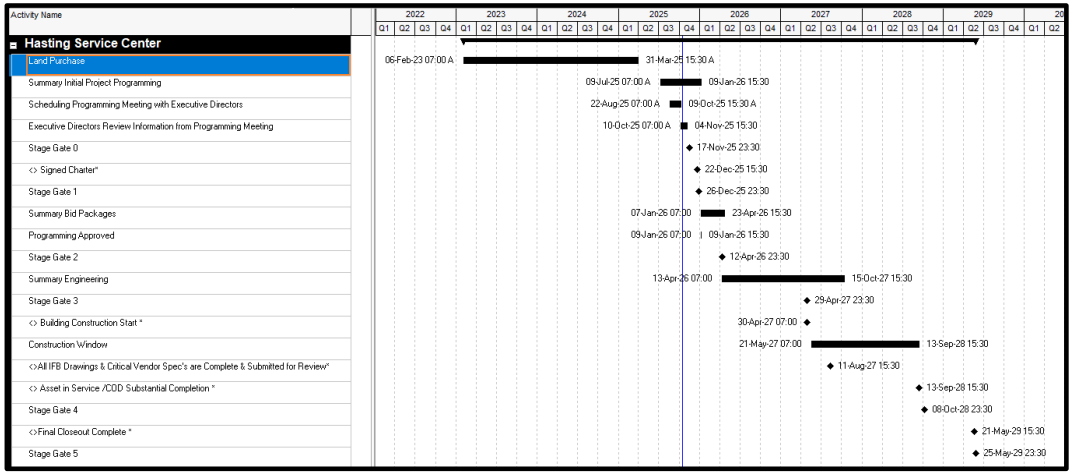
Alternative Scenario Evaluation Matrix - Hastings Service Center Major Systems Upgrade

	Weight	Build on New Site Score	Build on Ex. Site Score	Renov. Existing Score	Do Nothing Score	COMMENTS
Section 1 - Affordable (50%)						
Operating cost per square foot below statewide average	40%	4.0	4.0	2.0	1.0	Current facility operating cost for Hastings is $13.85 per square foot, versus statewide average operating cost of $5.31 per square foot.
Construction cost	10%	2.0	2.0	3.0	4.0	
Section 1 - Scenario Average Weighted Score Total (Best = 5):		1.8	1.8	1.1	0.8	
Section 2 - Safe (12.5%)						
Hazardous Material Abatement (asbestos, lead paint)	2.5%	4.00	4.0	3.0	2.0	
Reduced site congestion and improved vehicular traffic flow	10%	4.00	3.00	1.00	1.00	
Section 2 - Scenario Average Score Total (Best = 5):		0.5	0.4	0.2	0.2	
Section 3 - Reliable (25%)						
Overall score above 72 as measured by Facilites Scorecard	5%	4.0	4.0	3.0	1.0	Current overall facility score for Hastings is 41
On Premise start times improved by 5 to 10 minutes	10%	4.0	4.0	2.0	1.0	Improved material flow and vehicle loading
Drive through vehicle repair bays	5%	4.0	4.0	3.0	3.0	Improved vehicle repair time, reduced vehicle damage
Temporary relocation of operations	5%	4.0	1.0	2.0	4.0	
Section 3 - Scenario Weighted Score Total (Best = 5):		1.0	0.9	0.6	0.5	
Section 4 - Clean (12.5%)						
LEED V4.1 Certification	2.5%	4.0	4.0	2.0	1.0	
Stormwater detention and treatment	2.5%	4.0	4.0	3.0	1.0	Stormwater currently discharged to ditch
Onsite solar power generation	2.5%	4.0	4.0	1.0	1.0	
Municipal Utilities Available	5%	1.0	4.0	4.0	4.0	Available parcels are located outside Hastings urban area, private well and septic will be required
Section 3 - Scenario Weighted Score Total (Best = 5):		0.4	0.5	0.4	0.3	
TOTAL WEIGHTED VALUE SCORE: (BEST = 5)	100%	3.7	3.6	2.2	1.7	

Hastings Service Center – Alternatives Matrix Criteria

Safe
Hazardous Material Abatement (asbestos, lead paint)
Reduced site congestion and improved vehicular traffic flow
Affordable
Operating cost per square foot below statewide average
Construction cost
Reliable
Overall score above 72 as measured by Facilites Scorecard
On Premise start times improved by 5 to 10 minutes
Temporary relocation of operations
Drive through vehicle repair bays
Clean
LEED V4.1 Certification
Stormwater detention and treatment
Onsite solar power generation
Municipal Utilities Available
Non-Monetary Considerations
Other Risks & Barriers
Regulatory
Technical/Engineering
Aesthetics
People
Process
Technology
Customer Requirements
Real Estate
Municipality Requirements

Hastings Service Center – Project Schedule



Hastings Service Center – Project Expenditures v. Rate Case U-20963 Allowance

Hastings Service Center Project Spend ($)	2019 Total	2020 Total	2021 Total	2022 Total	2023 Total	2024 Total	2025 Total	Total Project Spend Thru 12/31/25	Hastings Service Center Case No. U20963 Allowance	Hastings Project Spend Thru 12/31/25 to U20963 Allowance
Electric Allocation	9,571	2,480	9,976	2,879	4,789	113,671	51,233	194,599	6,235,000	(6,040,401)
Gas Allocation	8,075	2,094	8,454	2,425	4,040	95,207	43,015	163,310	5,265,000	(5,101,690)
Total	17,646	4,574	18,430	5,304	8,829	208,878	94,248	357,909	11,500,000	(11,142,091)

Gas Call Drive Time Summary

- **For the current Hastings Service Center and the proposed site at Vacant Land M-179**
  - Within 20 minutes we are able to reach 50% of gas customers and in 40 minutes we are able to reach 100% of gas customers.
- **For the proposed site at Vacant Land Enterprise Drive**
  - Within 25 minutes we are able to reach 50% of gas customers and in 45 minutes we are able to reach 100% of gas customers.

Electric Outage Drive Time Summary

- **For the current Hastings Service Center and the proposed site at Vacant Land M-179**
  - Within 15 minutes we are able to reach 50% of electric customers and in 30 minutes we are able to reach 100% of electric customers.
- **For the proposed site at Vacant Land Enterprise Drive**
  - Within 20 minutes we are able to reach 50% of electric customers and in 30 minutes we are able to reach 100% of electric customers.

Summary Site Comparison

Vacant Land: Enterprise Dr

- Public water and septic
- Would add 5 minutes to both electric and gas drive times

Vacant Land: M-179

- Private water and septic
- Drive times would remain similar to what is being experienced at the current location

Hastings Service Center Site Options Comparison

Vacant Land: Enterprise Dr, Hastings, MI 49058

Characteristics:

- Property – 18 acres
- Municipal Water – Available at the street
- Municipal Sewer – Available at the street
- Fiber – Available
- Wetlands – No mitigation required
- 3-Phase – Available at the street
- Natural Gas – Available at the street

Vacant Land: M-179, Hastings, MI 49058

Characteristics:

- Property – 30 Acres
- Private Water System – New system needed
- Private Septic System – New system needed
- Fiber – Available
- Wetlands – No mitigation required
- 3-Phase – Available at the street
- Natural Gas – Available at the street

Vacant Land: M-179, Hastings, MI 49058

Location Description: Just west of the corner of M-43 and M-37, on M-179 at M-43. Just East of Kellogg Community College parcel.

Access: Main entrance off M-37

Owner: 2 property owners have been approached one being Kellogg Community College



Vacant Land: Enterprise Dr, Hastings, MI 49058

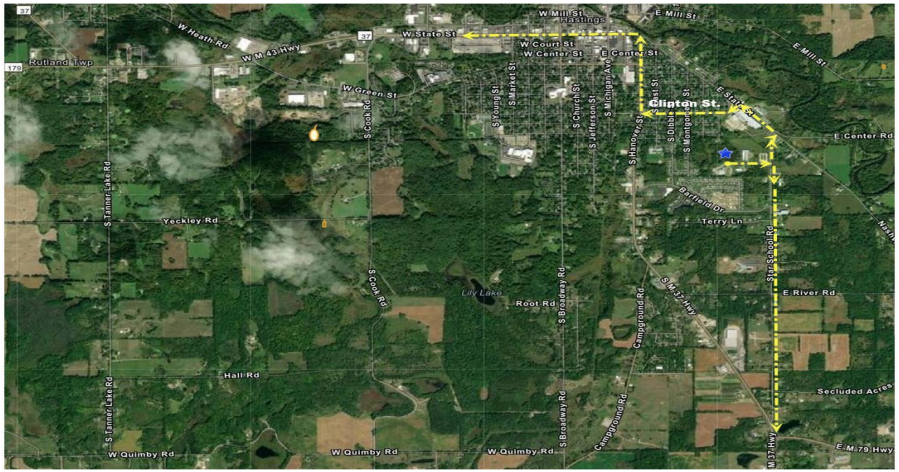
Location Description: Southeast in the City just off E State St and Star School Rd in the Industrial Park

Access: There could be multiple drives on E. Enterprise Dr. Northeast parcel has access to Star School Rd.

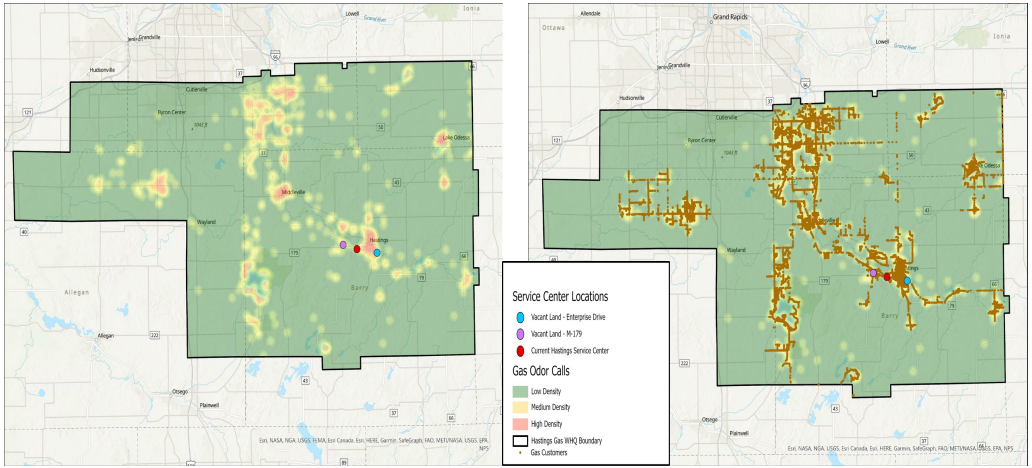
Owner: City of Hastings, parcels are currently for sale.



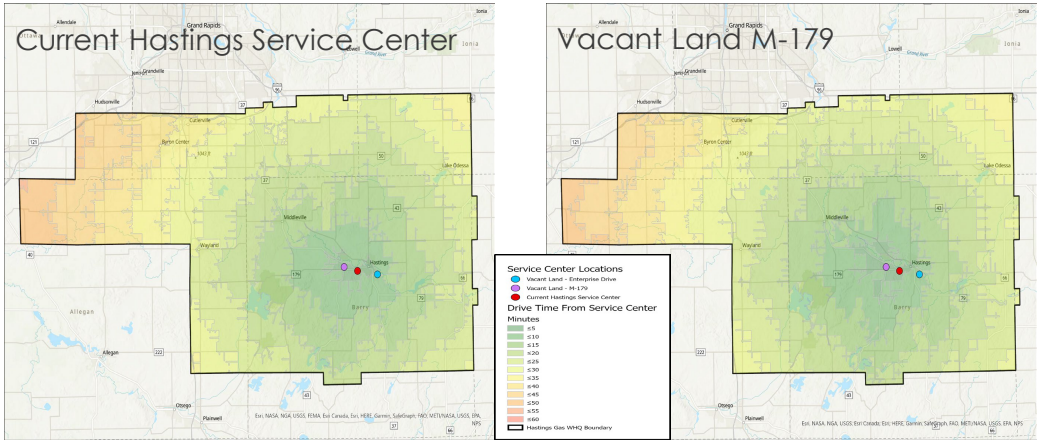
Class A Road Access Vacant Land Enterprise Dr.



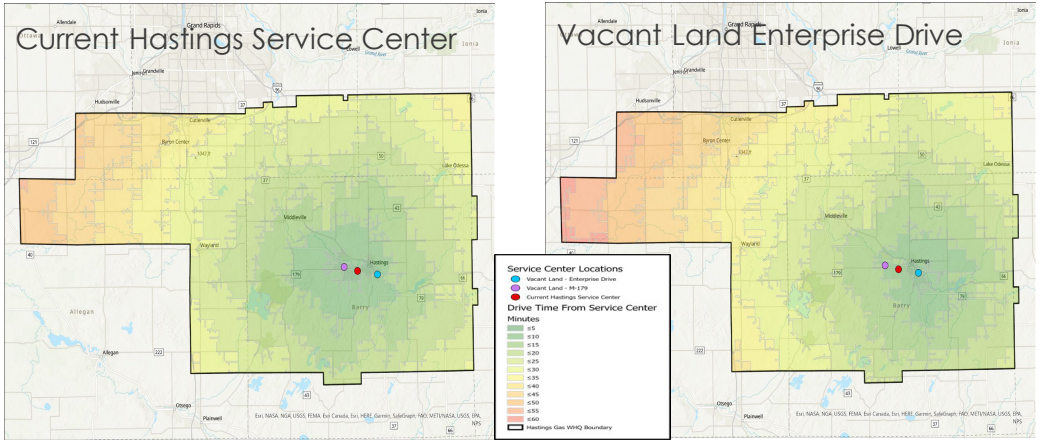
2019-2020 Density of Gas Odor Calls and Customer Data



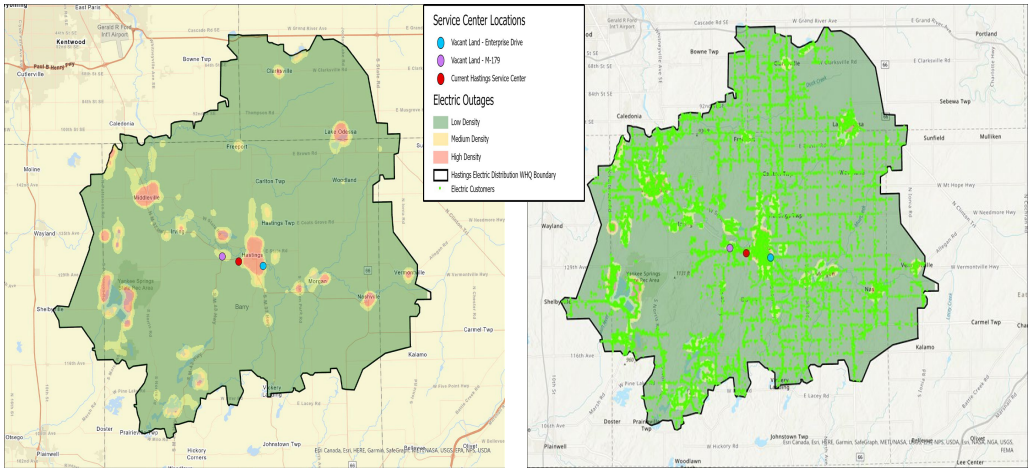
Gas Call Drive Times



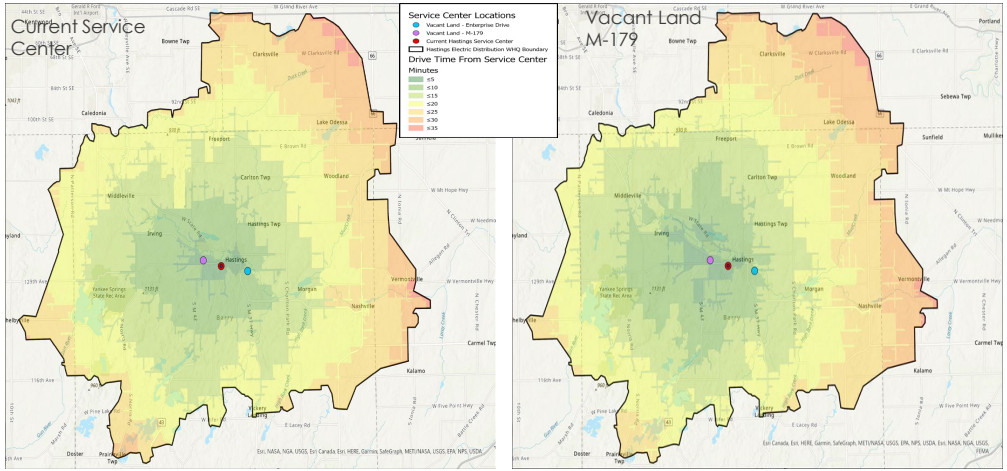
Gas Call Drive Times



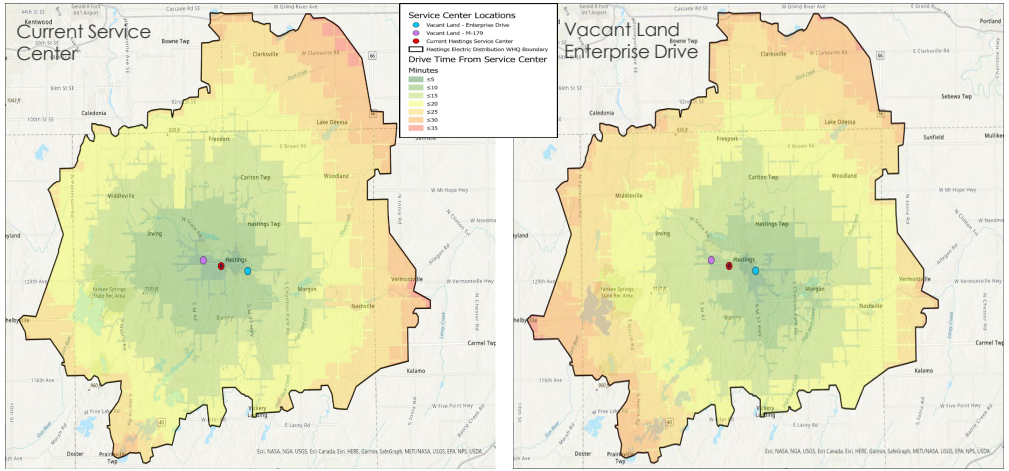
2019-2020 Density of Electric Outages and Customer Data



Electric Call Drive Times



Electric Call Drive Times



Renovations

List of Projects and Capital Expenditures

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Kalamazoo Service Center

Project Summary

Consumers Energy
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Kalamazoo Service Center – Health Assessment

Facility Assessment - Kalamazoo Service Center						
Location	Kalamazoo	Maximum Possible Points (80)	Serviceable > 48 Points	Poor < 48 Points	Good > 64 Points	
Zone	SWOM					
Safety						
Compatible Use	4	5	3	2	4	
Site Conditions	5	5	3	2	4	
Traffic/Site Flow	3	5	3	2	4	
Environmental Hazard	0	5	3	2	4	
Quality						
Branding	3	5	3	2	4	
Workplace Efficiency	3	5	3	2	4	
Years since last major systems upgrade	0	5	3	2	4	
Cost						
Facility Operating Costs	5	5	3	2	4	
Non Facility Cost Impact	4	5	3	2	4	
Space Optimization	1	5	3	2	4	
Delivery						
Drive Time	3	5	3	2	4	
Customer Response	4	5	3	2	4	
Sustainability	1	5	3	2	4	
Morale						
Employee Pride	1	5	3	2	4	
Retention	4	5	3	2	4	
Wellness	5	5	3	2	4	
Total	***46***	***80***	***48***	***32***	***64***	

Kalamazoo Service Center – Health Assessment

Safety (20 Points)	Comments	Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Compatible Use	Use of property is compatible with adjoining properties and surrounding area.	Industrial zoning and use	Residential use, retail use, criminal activity	Residential zoning, high crime area	Residential zoning	Mixed Commercial / Residential zoning	Commercial zoning for Service Centers, mixed Commercial / Industrial zoning for non-Service Centers	Industrial zoning for Service Centers, Commercial zoning for non-Service Centers	Industrial zoning for Service Centers, Central Business District zoning for non-Service Centers
Site Conditions	Physical condition of site	Full utilities, good paving, fencing, drainage	No utilities, poor paving, fencing, drainage	Site not adequate to support operational requirements, located in flood plain,	Site not adequate to support operational requirements	significant upgrades, such as storm water detention, fire water, potable water, sanitary sewer, paving, etc.	Site in serviceable condition with full utilities or good condition with partial utilities	Site in good condition, full utilities	Site in good condition with undeveloped space to accommodate future growth
Traffic/Site Flow	Road network, site access drive, vehicle turning space	Close to highway, access from two roads, space for truck trailer to pull off road, one way gates	Secondary road, no truck pull off space at gate, two way gates, insufficient turning space	Unimproved road frontage / site traffic flows crossing	Non Class A road frontage / Site heavy traffic and light traffic flows crossing	with impediments, railroad tracks, intersections, etc. / Site traffic flows crossing	Class A road frontage / Site traffic flows mixed	Class A road frontage with secondary frontage / Site traffic flows separated	with secondary frontage and nearby highway access / Site traffic flows separated
Environmental Hazard	Environmental hazards	LEED certification, no environmental hazards	Former MGP site, soil contamination, abandoned underground fuel tanks, abandoned transformer storage, asbestos fire proofing, asbestos duct wrap, asbestos pipe wrap, lead paint,	Immediate hazards to employees present during normal use of site	Hazardous materials present, with reoccurring or continuous exposure hazard, former MGP site, current 201 site	Hazardous materials present in manageable form, former MGP site, current 201 site	Hazardous materials present in manageable form	No environmental impacts, hazardous materials abated or encapsulated	LEED Certified facility with no environmental impacts

Quality (15 Points)	***Employee/Customer Engagement***	Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Branding	Projects positive image to community and potential employees	Well cared for facility, curb appeal, neat landscaping, coordinated site signage	Dilapidated facility, dated appearance, overgrown landscaping, mismatched site signage	damaged or deteriorated structures, landscape materials overgrown or absent, failed pavement, etc.	Structures deteriorated, landscape materials overgrown or absent, failing paving, no signage	Structures poorly maintained, landscape materials overgrown or absent, poor signage	for, landscape materials in serviceable condition, uncoordinated signage	Structures well cared for, landscape materials in good condition, coordinated signage	New facility, landscape materials in good condition, coordinated signage
Workplace Efficiency	Space is fully utilized	Space provided for all operational functions, space size meets needs, proper inventory stored	Space not provided for all operational functions, space oversized, space not fully utilized, unused materials (junk) stored	Space inadequate for intended occupancy	Hard wall offices, empty or vacant spaces	Hard wall offices, fully utilized	Mix of hard wall offices and systems furniture, fully utilized	Modular systems furniture, fully utilized	Flexible, open and collaborative workspaces, modular systems furniture, fully utilized
Years since last major systems upgrade	Condition of facility is code compliant, building systems are within normal operational life cycle and supports working environment	New construction or recently completed full renovation	Building old and unrenovated or only minimal or partial renovation work completed	initial construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade	initial construction or last major systems upgrade

Kalamazoo Service Center – Health Assessment

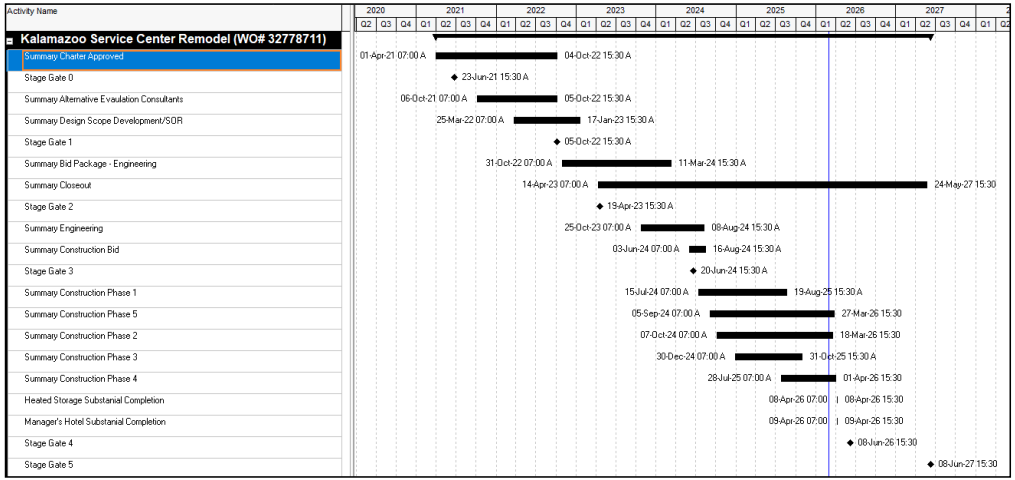
Cost (15 Points)		Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Facility Operating Costs	O&M costs to operate and maintain facility	Cost per square foot for facility less than statewide average cost per square foot ($5.31)	Cost per square foot for facility more than statewide average cost per square foot ($5.31)	costs greater than $10.00 per square foot	costs between $8.00 to $10.00 per square foot	costs between $7.25 to $7.99 per square foot	costs between $7.00 to $7.24 per square foot	costs between $5.75 to $6.99 per square foot	Combined operating costs less than $5.75 per square foot
Non Facility Cost Impact	O&M cost impacts to operations	Building correct size, centrally located within customer base area, able to accommodate necessary materials, able to maneuver onsite	Building too large, eccentrically located within customer base area, unable to accommodate necessary materials, difficult to maneuver onsite	Building eccentrically located within service territory, inadequate space	Building eccentrically located within service territory, underutilized space	Building eccentrically located within service territory	Building centrally located within service territory	Building accommodates operational needs, centrally located within service territory	Building accommodates operational need, space utilized efficiently, centrally located within service territory
Space Optimization	Reduce excess square footage	Space fully utilized, space utilized efficiently	Space under utilized, space utilized inefficiently, indoor parking area	Building vacant	Building partially occupied or partially vacant	Building occupied inefficiently, includes IPA	Building fully occupied, includes IPA	Building fully occupied, no IPA	occupied, no IPA, includes cold storage

Delivery (15 Points)	Customer Service	Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Drive Time	Service territory area of proper size	Centrally located within service area(s), drive time balanced across territory and within targeted limits	Eccentrically located within service area(s), drive time unbalanced across territory and/or exceeds targeted limits	service territory and size of service territory allows drive time >1:20 Gas and >1:30 Electric	service territory and size of service territory allows drive time < 1:20 Gas and <1:30 Electric	service territory and size of service territory allows drive time < 1:10 Gas and <1:15 Electric	service territory and size of service territory allows drive time < 1:00 Gas and <1:00 Electric	service territory and size of service territory allows drive time < 0:50 Gas and <0:45 Electric	service territory and size of service territory allows drive time < 0:40 Gas and <0:30 Electric
Customer Response	Meets needs of customers	Customer response time metrics fall below targets	Customer response times exceed targets	response times meet target <90% of time, Electric CAIDI >215 minutes	response times meet target >90% of time, Electric CAIDI <215 minutes	response times meet target >95% of time, Electric CAIDI <195 minutes	response times meet target >97% of time, Electric CAIDI <180 minutes	response times meet target >98% of time, Electric CAIDI <165 minutes	response times meet target >99% of time, Electric CAIDI <150 minutes
Sustainability	Facility incroprates reduced energy utilization and minimizes environmental impact	Facility constructed in accordance with recent Energy Codes, includes onsite stormwater treatment, Green building certification	Facility constructed with no insulation, utilizes enegy intensive equipment, no onsite storm water treatment	Minimal roofing insulation	Upgraded roofing insulation	Upgraded roofing insulation and windows	Upgraded roofing insulation, windows and building envelope	insulation, windows, and building envelope with onsite storm water treatment	LEED Certified (or higher LEED rated) facility

Kalamazoo Service Center – Health Assessment

Morale (15 Points)				Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Employee Wellness		Pro	Con						
Employee Pride	Employees are engaged	Employee engagement scores > company average	Employee engagement scores < company average	Deteriorated facility	Deteriorated or dated facility with limited amenities	Dated facility with minimal amenities	Dated facility with full amenities and onsite parking	Modern facility with full amenities	Modern facility with full amenities, onsite parking
Retention	Facilities located in a desirable area, space is attractive to Millennials and supports millennial work styles	Downtown location, local amenities available, space supports varied work styles	Remote location, few local amenities, fixed work space	Remote location, no local amenities	some amenities available within 20 minutes driving distance	Remote location, amenities available within 20 minutes driving distance	Remote location, amenities available within 15 minutes driving distance	Diverse location, amenities available within 10 minutes driving distance	Diverse location, amenities available within walking distance
Wellness	Wellness facilities	Wellness room, space for trainer, drinking fountain, shower facilities nearby, space for wellness classes, well maintained exercise equipment, mirrors, lockers	Wellness room combined with non-compatible uses (i.e.: conference room), aged exercise equipment, poorly maintained exercise equipment, remote shower facilities	No shower, drinking fountain, Wellness or Nursing Mother Room, no additional space available	Shower and drinking fountain, no Wellness or Nursing Mother Room, no additional space available	Wellness Room or Nursing Mother Room, shower and drinking fountain, no additional space available	Nursing Mother Room, shower and drinking fountain, with space available to add Wellness or NMR	Wellness Room and Nursing Mother room, shower and drinking fountain, with space available for Trainer	Wellness room, Trainer room, Nursing Mother Room, shower and drinking fountain nearby

Kalamazoo Service Center – Project Schedule

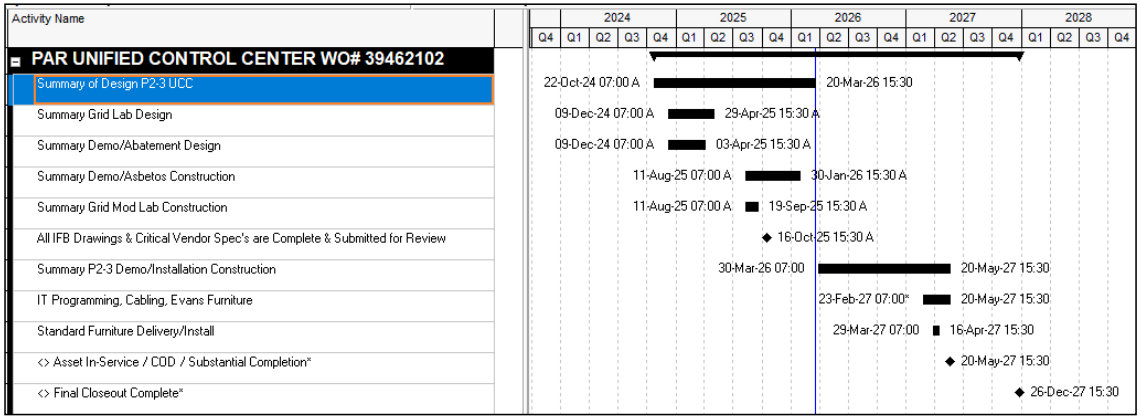


Kalamazoo Service Center – Project Expenditures v. Rate Case U-20963 Allowance

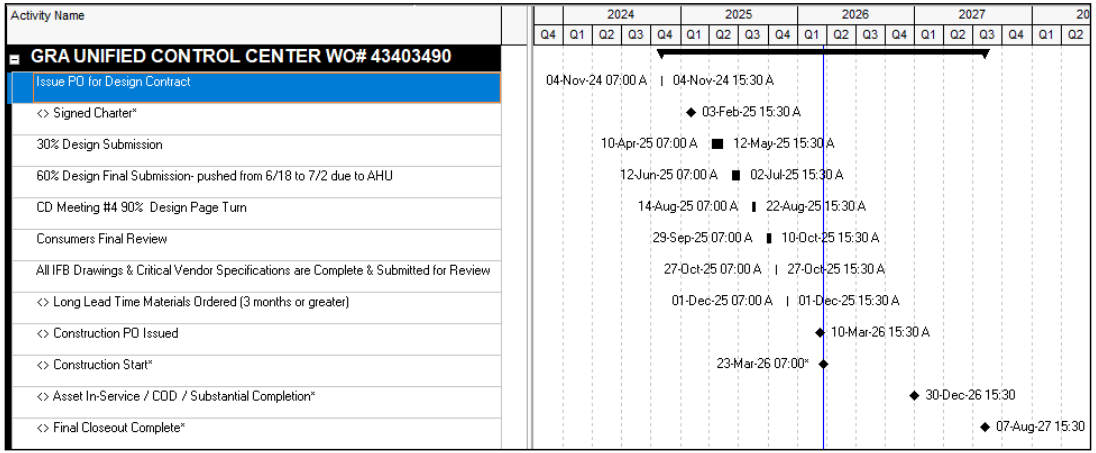
Kalamazoo Service Center Project Spend ($)	2018 Total	2019 Total	2020 Total	2021 Total	2022 Total	2023 Total	2024 Total	2025 Total	Total Project Spend Thru 12/31/25	Kalamazoo Service Center Case No. U20963 Allowance	Variance - Total Kalamazoo Project Spend Thru 12/31/25 to U20963 Allowance	(%) of U20963 Allowance Spent Thru 12/31/25
Electric Allocation	30,965	148,508	877	25,008	181,585	482,479	4,550,695	9,430,192	14,819,344	16,646,000	(1,826,656)	89%
Gas Allocation	25,998	125,289	741	21,191	152,887	407,048	3,811,479	7,917,475	12,436,110	14,056,000	(1,619,890)	88%
Total	56,963	273,797	1,618	46,199	334,472	889,527	8,362,174	17,347,667	27,255,454	30,702,000	(3,446,546)	89%


Control / Dispatch Center
Project Summary
Consumers Energy
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9

Control / Dispatch Center Parnall – Project Schedule



Control / Dispatch Center Grand Rapids – Project Schedule



Control / Dispatch Center – Project Expenditures v. Rate Case U-21389 Allowance

Control / Dispatch Center Project	2021 Total	2022 Total	2023 Total	2024 Total	2025 Total	Total Project Spend Thru 12/31/25	Control / Dispatch Center Case No. U21389 Allowance	Variance - Total Control / Dispatch Center Thru 12/31/25 to U21389 Allowance	(%) of U21389 Allowance Spent Thru 12/31/25
Grand Rapids	0	0	0	641,687	2,180,158	2,821,845			
Parnall	0	80,871	0	1,764,348	3,333,882	5,179,101			
Total	0	80,871	0	2,406,035	5,514,040	8,000,946	6,854,000	1,146,946	117%

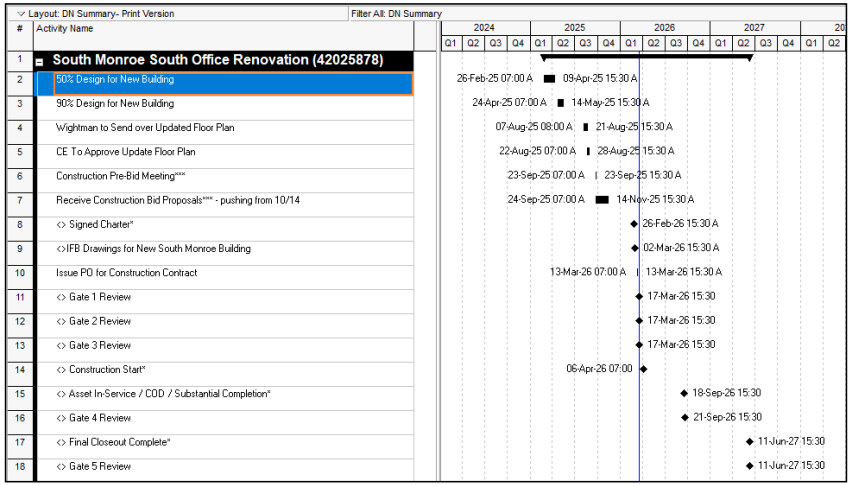
Notes:
- *Project is 100% Electric Allocation*
- *Allowances granted are for the Control / Dispatch Center Project in Total*

South Monroe Renovation

Project Summary

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South Monroe – Project Schedule

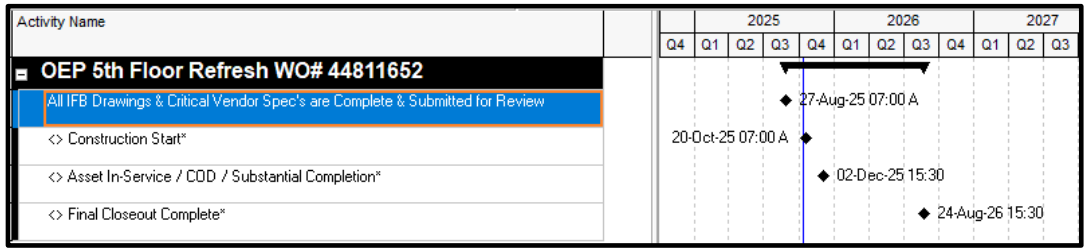


OEP 5 Refresh

Project Summary

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OEP 5 Refresh – Project Schedule



OEP 5 Refresh – Project Expenditures

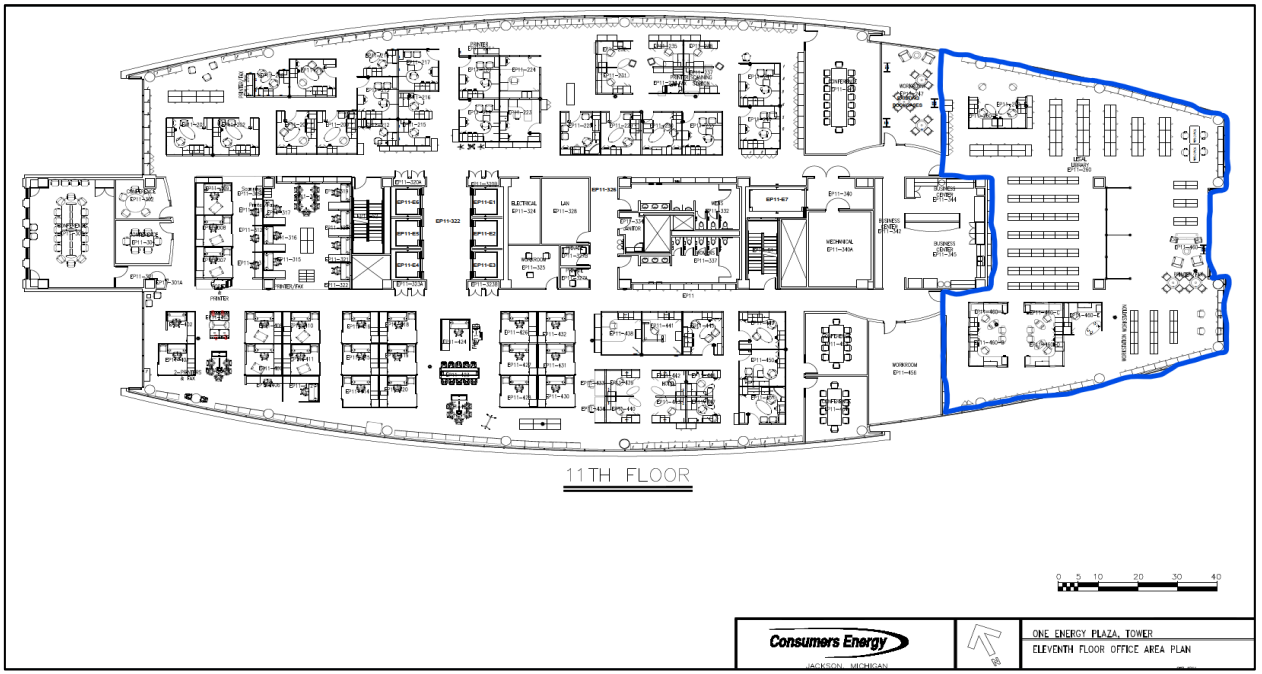
OEP5 Refresh Project Spend ($)	2025 Total	2026 Forecast	Total Project Spend
Electric Allocation	792,615	52,440	845,055
Gas Allocation	665,470	44,028	709,498
Total	1,458,085	96,468	1,554,553

Legal Library Renovation

Project Summary

Consumers Energy
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Legal Library – OEP 11th Floor



Birch Run Acquisition

Project Summary

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Birch Run New Construction Alternative

New Construction Alternative

(37,500 FT2) x (*$260 / FT2) = $9,750,000

(Building Area) x (*Construction Cost) = Estimated Total Project Cost

Site Acquisition Alternative

($4,924,000) + ($947,000) = ($5,871,000)

(Site Acquisition Cost) + (Cost Needed Improvements) = (Estimated Total Project Cost)

** $260 per square foot all-in construction estimate derives from RS Means Construction Cost Data*

Birch Run Property Visual

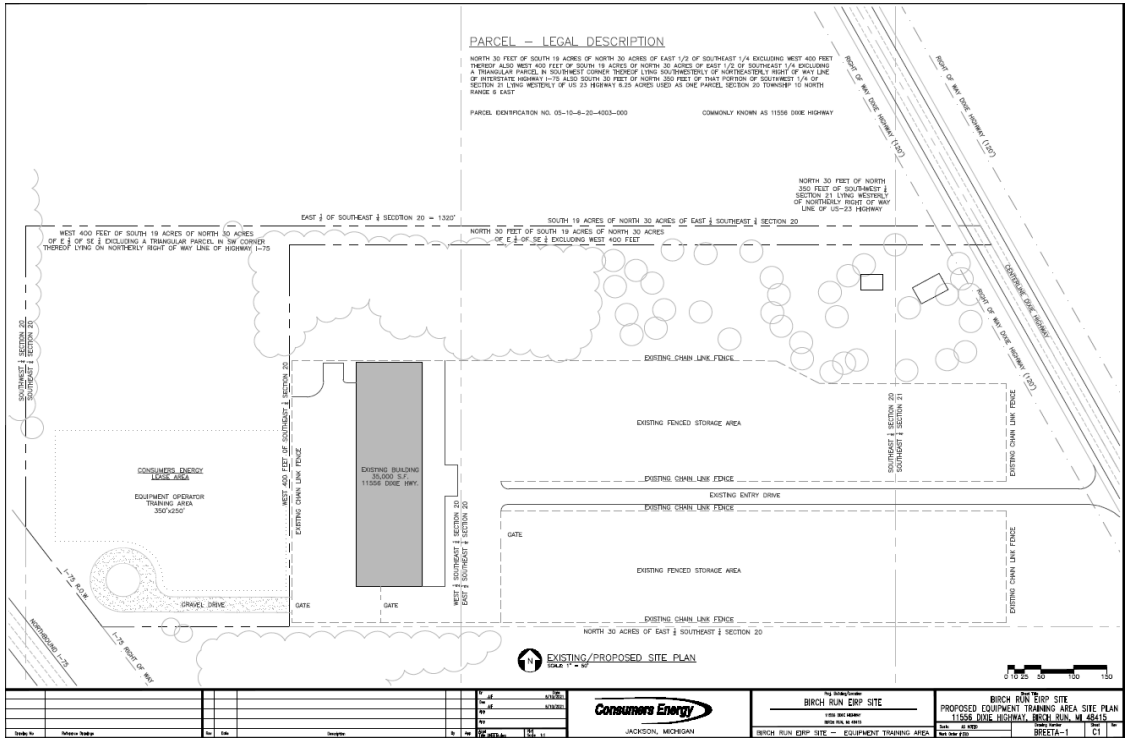


Note: Property record encapsulated by blue line includes the site being acquired

Birch Run Facility Visual



Birch Run Site Plan



New East Kent Project

Project Summary

Consumers Energy
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Current East Kent Facility Visual



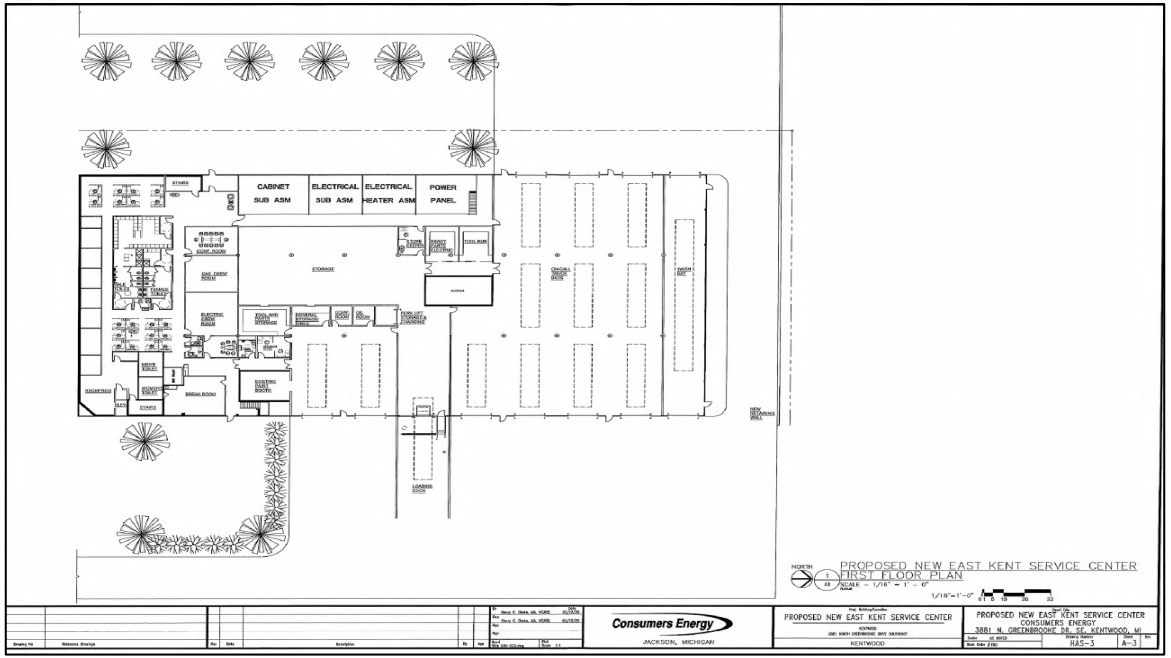
Note: Property encapsulated by green line constitutes the existing site. Building encapsulated by the blue line is the existing facility.



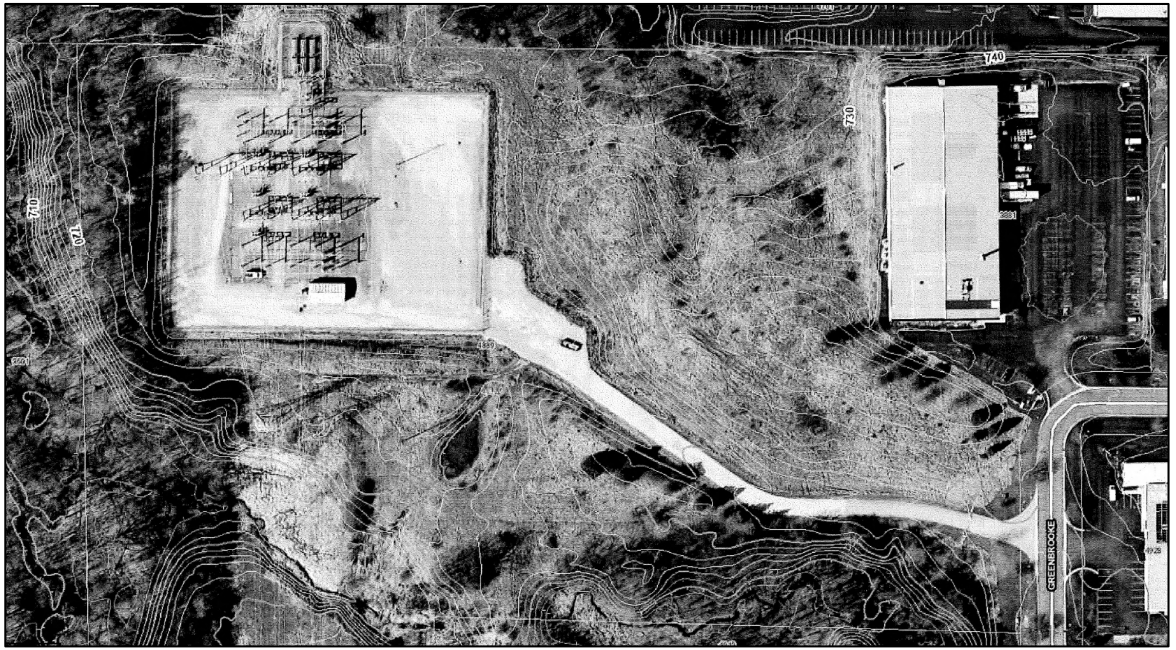
Proposed New East Kent Facility

- Current Sale Offer: $5.2 million
- 4501 40th Street S.E., Kentwood, MI 49512
- Adjacent to existing Company property (Plaster Creek Electric Substation – 53 acres).
- 3.8 acres with adjoining acreage from Company property and secondary entrance from Plaster Creek Electric Substation access
- Building footprint (40,660 FT2)
- Second story office (5,520 FT2)
- Mezzanine (7,176 FT2)

Proposed New East Kent Facility – First Floor Plan



Proposed New East Kent Facility – Site



S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

JOSHUA W. HAHN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Power Supply Cost Recover Forecast for May 1, 2027 - April 30, 2028

Case No.: U-22070
Exhibit No.: A-140 (JWH-1)
Page: 1 of 3
Witness: JWHahn
Date: June 2026

SUMMARY BY SOURCE

YEAR		2027 MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2028 JAN	FEB	MAR	APR	TOTAL
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	ENERGY (MWH)													
1	COAL STEAM	0	0	0	0	0	0	0	0	0	0	0	0	0
2	GAS & OIL	1,201,166	1,316,670	1,424,370	1,365,198	1,095,143	1,149,873	1,260,908	1,491,829	1,336,259	1,030,062	1,234,624	1,153,815	15,059,917
3	NUCLEAR PPA	0	0	0	0	0	0	0	0	0	0	0	0	0
4	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
5	CE OWNED RENEWABLES	362,671	346,256	307,684	294,419	269,662	308,564	310,496	237,720	254,140	344,406	433,828	429,247	3,899,093
6	LCREP RENEWABLES	28,621	23,316	17,461	19,041	22,535	34,075	43,455	39,391	34,867	40,877	42,040	35,348	381,027
7	PEAKERS	192,086	249,539	260,769	260,769	194,501	149,007	175,548	28,693	22,352	171,349	199,992	87,477	1,992,082
8	PUMPED STORAGE	10,425	2,047	20,971	10,533	10,747	3,788	12,856	7,809	12,243	19,439	16,462	25,311	152,630
9	TOTAL GENERATED	1,794,969	1,937,828	2,031,255	1,949,960	1,592,588	1,645,307	1,803,263	1,805,442	1,659,861	1,606,133	1,926,946	1,731,198	21,484,749
10	LESS : PUMPING	-20,403	-4,422	-27,890	-14,907	-9,589	-6,246	-17,023	-12,650	-16,996	-23,136	-22,681	-34,949	-210,892
11	TOTAL GENERATED	1,774,566	1,933,406	2,003,365	1,935,052	1,582,999	1,639,061	1,786,240	1,792,792	1,642,865	1,582,997	1,904,265	1,696,249	21,273,857
12	PURCHASED (PPAs)	924,853	1,308,751	1,437,714	1,374,264	1,109,095	836,584	845,283	517,406	460,065	912,570	1,025,399	769,148	11,521,132
13	NET INTERCHANGE	239,802	22,295	68,813	121,345	329,478	446,845	326,931	915,607	1,100,150	574,215	139,351	386,524	4,671,356
14	**TOTAL SYSTEM REQUIREMENTS**	2,939,221	3,264,452	3,509,892	3,430,661	3,021,572	2,922,490	2,958,454	3,225,805	3,203,080	3,069,782	3,069,015	2,851,921	37,466,345
	VARIABLE EXPENSES ($*1000)													
15	COAL STEAM	0	0	0	0	0	0	0	0	0	0	0	0	0
16	GAS & OIL	29,670	32,572	38,120	37,080	30,165	31,808	37,068	50,676	45,378	30,696	30,685	25,073	418,993
17	NUCLEAR PPA VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
18	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
19	CE OWNED RENEWABLES	12,322	11,805	10,939	10,783	9,758	12,964	14,643	12,759	13,068	15,731	17,882	15,319	157,974
20	PEAKERS	6,085	8,332	9,204	9,344	7,211	5,503	6,779	2,222	1,016	6,585	6,738	2,567	71,587
21	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
22	TOTAL GENERATED	48,078	52,710	58,264	57,207	47,134	50,275	58,491	65,658	59,462	53,012	55,305	42,959	648,553
23	LESS : PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0
24	TOTAL GENERATED	48,078	52,710	58,264	57,207	47,134	50,275	58,491	65,658	59,462	53,012	55,305	42,959	648,553
25	PURCHASED (PPAs) VARIABLE COST[1]	40,211	59,105	69,902	67,385	49,883	36,449	34,267	21,949	26,505	45,244	48,617	39,549	539,067
26	NET INTERCHANGE, EXCLUDING ZRC	5,577	-415	863	2,766	9,722	15,010	11,426	35,894	44,331	22,672	2,935	7,908	158,689
27	**TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE**	**93,866**	**111,400**	**129,029**	**127,358**	**106,739**	**101,734**	**104,183**	**123,500**	**130,299**	**120,928**	**106,856**	**90,416**	**1,346,309**
28	ZONAL RESOURCE CREDIT PURCHASE	1,188	641	662	662	641	662	641	662	662	598	662	641	8,326
29	OWNED RENEWABLE CAPACITY	7,178	6,877	6,372	6,282	5,684	7,552	8,530	7,433	7,612	9,164	10,417	8,924	92,024
30	NUCLEAR PPA CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
31	PURCHASED (PPA) CAPACITY	20,717	19,593	20,404	20,283	18,253	17,943	17,155	15,330	16,197	16,676	18,894	18,680	220,126
32	PURCHASED (PPA) FIXED ENERGY	7,144	6,699	6,825	6,771	6,452	6,391	6,102	5,946	5,933	6,110	6,622	6,678	77,672
33	INDEPENDENT ADMINISTRATOR EXPENSE	0	0	0	0	0	50	50	50	50	50	0	0	250
34	**TOTAL CAPACITY AND PPA FIXED COSTS**	**36,227**	**33,810**	**34,264**	**33,998**	**31,030**	**32,598**	**32,478**	**29,421**	**30,455**	**32,598**	**36,595**	**34,924**	**398,398**
35	TOTAL TRANSMISSION AND ENERGY MARKETS ADMINISTRATION	60,622	69,238	71,838	69,220	63,201	51,600	52,513	53,730	53,840	55,096	52,802	49,849	703,549
36	ACTIVATED CARBON	0	0	0	0	0	0	0	0	0	0	0	0	0
37	MISO - SCHEDULE 2 (REACTIVE)	0	0	0	0	0	0	0	0	0	0	0	0	0
38	AQUEOUS AMMONIA EXPENSE	212	212	212	212	212	212	212	212	210	210	210	210	2,540
39	UREA EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0	0
40	LIME EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0	0
41	NOX ALLOWANCE	0	0	0	0	0	0	0	0	0	0	0	0	0
42	**TOTAL POWER SUPPLY COSTS**	**190,927**	**214,660**	**235,343**	**230,789**	**201,182**	**186,144**	**189,387**	**206,864**	**214,804**	**208,832**	**196,464**	**175,399**	**2,450,796**
43	LONG-TERM INDUSTRIAL LOAD RETENTION RATE (LTILRR)	10,318	8,672	9,169	9,777	12,086	9,385	10,934	12,077	11,320	10,912	8,217	9,343	122,209
44	LARGE ECONOMIC DELVEOPMENT RATE	7,030	8,306	8,868	9,256	8,754	8,291	9,201	9,668	10,453	10,382	8,846	8,104	107,159
45	**TOTAL POWER SUPPLY COSTS LESS LTILRR PAYMENTS**	**173,580**	**197,682**	**217,306**	**211,756**	**180,343**	**168,468**	**169,253**	**185,119**	**193,031**	**187,538**	**179,401**	**157,952**	**2,221,428**

[1]Purchased (PPA) variable costs include costs associated with PURPA variable energy payments, non-capacity renewable energy plan transfer costs, the green generation program, energy only PPAs and certain hydro plant contract costs

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Power Supply Cost Recover Forecast for May 1, 2027 - April 30, 2028

Case No.: U-22070
Exhibit No.: A-140 (JWH-1)
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PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2027 MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2028 JAN	FEB	MAR	APR	TOTAL
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	PURCHASED AND NET INTERCHANGE RECEIVED (MWH)													
47	MARKET ON PEAK	8,354	13,346	15,395	18,683	26,189	21,781	13,175	69,033	90,889	33,975	37,363	68,199	416,383
48	MARKET OFF PEAK	963,773	923,835	982,845	971,062	1,040,300	1,020,191	975,558	1,119,475	1,247,221	1,009,931	981,488	962,853	12,198,533
49	PURCHASED (PPAs)	924,853	1,308,751	1,437,714	1,374,264	1,109,095	836,584	845,283	517,406	460,065	912,570	1,025,399	769,148	11,521,132
50	TOTAL RECEIVED	1,896,981	2,245,933	2,435,954	2,364,008	2,175,583	1,878,556	1,834,017	1,705,914	1,798,176	1,956,476	2,044,249	1,800,200	24,136,048
	NET INTERCHANGE DELIVERED (MWH)													
51	EXTERNAL SALES	732,326	914,887	929,427	868,399	737,011	595,127	661,803	272,901	237,960	469,691	879,499	644,528	7,943,559
52	MISO RAC	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TOTAL DELIVERED	732,326	914,887	929,427	868,399	737,011	595,127	661,803	272,901	237,960	469,691	879,499	644,528	7,943,559
54	NET (MWH)	1,164,655	1,331,045	1,506,527	1,495,609	1,438,573	1,283,429	1,172,213	1,433,014	1,560,216	1,486,785	1,164,750	1,155,672	16,192,489

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Power Supply Cost Recover Forecast for May 1, 2027 - April 30, 2028

Case No.: U-22070
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YEAR		2027 MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2028 JAN	FEB	MAR	APR	TOTAL
		PURCHASED AND INTERCHANGE POWER REPORT												
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000)													
56	MARKET ON PEAK ENERGY	225	454	464	353	759	737	507	2,840	3,838	1,402	1,085	1,496	14,159
57	MARKET OFF PEAK ENERGY	30,993	34,898	40,509	39,874	38,444	36,101	37,107	45,527	52,377	41,605	34,625	27,656	459,717
58	PURCHASED (PPAs) ENERGY	39,528	58,722	69,429	66,907	49,491	36,056	33,880	21,513	26,045	44,837	48,226	39,171	533,804
59	CASE NO. U-16048 COST RECOVERY	684	383	473	478	392	393	387	435	461	407	391	378	5,263
60	TOTAL EXPENSE	71,430	94,457	110,875	107,612	89,086	73,287	71,882	70,315	82,720	88,251	84,327	68,702	1,012,943
	NET INTERCHANGE CREDIT ($*1000)													
61	EXTERNAL SALE ENERGY	25,641	35,765	40,109	37,461	29,481	21,829	26,188	12,472	11,884	20,335	32,777	21,245	315,186
62	EXTERNAL SALE CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
63	MISO RAC	0	0	0	0	0	0	0	0	0	0	0	0	0
64	TOTAL CREDIT	25,641	35,765	40,109	37,461	29,481	21,829	26,188	12,472	11,884	20,335	32,777	21,245	315,186
65	NET EXPENSE	45,789	58,691	70,766	70,152	59,606	51,458	45,694	57,843	70,836	67,916	51,550	47,456	697,757

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Consumers Energy Forecast – Energy Market Sales Revenue and Total Variable Expense

Case No.: U-22070
Exhibit No.: A-141 (JWH-2)
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Witness: JWHahn
Date: June 2026

Capacity Cost Offsets for State Reliability Mechanism Capacity Charge

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	ENERGY (MWH)	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**Total**
1	COAL STEAM	0	0	0	0	0	0	0	0	0	0	0	0	0
2	GAS & OIL	1,201,166	1,316,670	1,424,370	1,365,198	1,095,143	1,149,873	1,260,908	1,491,829	1,336,259	1,030,062	1,234,624	1,153,815	15,059,917
3	NUCLEAR PPA	0	0	0	0	0	0	0	0	0	0	0	0	0
4	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
5	CE OWNED RENEWABLES	362,671	346,256	307,684	294,419	269,662	308,564	310,496	237,720	254,140	344,406	433,828	429,247	3,899,093
6	PEAKERS	192,086	249,539	260,769	260,769	194,501	149,007	175,548	28,693	22,352	171,349	199,992	87,477	1,992,082
7	PUMPED STORAGE	10,425	2,047	20,971	10,533	10,747	3,788	12,856	7,809	12,243	19,439	16,462	25,311	152,630
8	LESS : PUMPING	-20,403	-4,422	-27,890	-14,907	-9,589	-6,246	-17,023	-12,650	-16,996	-23,136	-22,681	-34,949	-210,892
9	PURCHASED (PPAs)	924,853	1,308,751	1,437,714	1,374,264	1,109,095	836,584	845,283	517,406	460,065	912,570	1,025,399	769,148	11,521,132
10	TOTAL GENERATED	2,670,798	3,218,841	3,423,618	3,290,275	2,669,559	2,441,570	2,588,068	2,270,807	2,068,063	2,454,690	2,887,624	2,430,049	32,413,962
					2027						2028			
		MAY	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**Total**
11	**Market Price ($/MWh)**	32.30	37.95	41.56	41.31	37.68	35.41	38.24	41.09	42.75	41.44	35.45	29.06	37.85
					2027						2028			
		MAY	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**Total**
12	**Energy Market Sales Revenue ($k)**	86,267	122,155	142,286	135,921	100,589	86,456	98,968	93,307	88,410	101,722	102,366	70,617	**1,229,064**
					2027						2028			
	CE OWNED FUEL EXPENSE ($k)	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**Total**
13	COAL STEAM	0	0	0	0	0	0	0	0	0	0	0	0	0
14	GAS & OIL	29,670	32,572	38,120	37,080	30,165	31,808	37,068	50,676	45,378	30,696	30,685	25,073	418,993
15	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
16	CE OWNED RENEWABLES	12,322	11,805	10,939	10,783	9,758	12,964	14,643	12,759	13,068	15,731	17,882	15,319	157,974
17	PEAKERS	6,085	8,332	9,204	9,344	7,211	5,503	6,779	2,222	1,016	6,585	6,738	2,567	71,587
18	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
19	TOTAL FUEL EXPENSE	48,078	52,710	58,264	57,207	47,134	50,275	58,491	65,658	59,462	53,012	55,305	42,959	**648,553**
20	**PPA VARIABLE EXPENSE (K$)**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**Total**
21	NUCLEAR PPA VARIABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
22	PURCHASED (NUGs) VARIABLE COST	40,211	59,105	69,902	67,385	49,883	36,449	34,267	21,949	26,505	45,244	48,617	39,549	539,067
23	TOTAL PPA VARIABLE EXPENSE	40,211	59,105	69,902	67,385	49,883	36,449	34,267	21,949	26,505	45,244	48,617	39,549	**539,067**

24	**Total Variable Expense ($k)**	**648,553**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-22070
Exhibit No.: A-142 (JWH-3)
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Date: June 2026

Summary of PPA Changes from September 30, 2025 to February 1, 2026

Line	(a) PPA	(b) Change	(c) MPSC Case No. U-21946 2026 PSCR Plan Case Commercial Operation Date Forecast (As of Sept 30, 2025)	(d) Commercial Operation Date Estimated	(e) Nameplate (MW)	(f) Contract Source
1	Grand Basin Energy Storage	New PPA	U-20165	6/1/2027	100	IRP
2	Watertown Solar	New PPA	U-20165	7/1/2027	150	IRP
3	Pivot Energy MI 9	New PPA	U-20604	3/26/2028	5	PURPA
4	Pivot Energy MI 20	New PPA	U-20604	4/2/2028	1.875	PURPA
5	Acceleration Solar	New PPA	U-20165	6/1/2028	90	IRP
6	Hawkeye Solar I	New PPA	U-20165	6/1/2028	200	IRP
7	Hawkeye Solar II	New PPA	U-20165	6/1/2028	250	IRP
8	Portside Solar	New PPA	U-20165	6/1/2028	80	IRP
9	Hackett Energy Storage	New PPA	U-20165	6/1/2028	100	IRP
10	Lakeside Energy Storage	New PPA	U-20165	6/1/2028	100	IRP
11	Voyager II Energy Storage	New PPA	U-20165	6/1/2028	150	IRP
12	Moonshine Solar	New PPA	U-20165	6/1/2028	150	IRP
13	Pivot Energy MI 1	New PPA	U-20604	7/31/2028	1.875	PURPA
14	Pivot Energy MI 19	New PPA	U-20604	7/31/2028	2	PURPA

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

JOSHUA J. JUDY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Fleet Services
($000)

Case No.: U-22070
Exhibit No.: A-12 (JJJ-1)
Schedule: B-5.1
Page: 1 of 3
Witness.: JJJudy
Date: June 2026

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Period* 12 Mos Ended 12/31/2026	(d) Projected Bridge Period* 4 Mos Ending 4/30/2027	(e) Projected Bridge Period* 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
1	Fleet Vehicle Capital Replacement	22,054	20,359	3,235	23,594	20,868
2	Fleet Capital Replacement - Additional	0	33,150	0	33,150	0
3	Fleet Vehicle Electrification	0	1,040	0	1,040	500
4	Fleet Expansion	856	10,905	7,234	18,139	5,000
5	Fleet Business Partner Funded	734	0	0	0	0
6	Fleet Tools - Garage	271	257	88	345	265
7	Total Fleet Services Capital	23,915	65,711	10,557	76,268	26,633

		Projected* 4 Mos Ending 4/30/2026	Projected* 12 Mos Ending 4/30/2027	Projected* 12 Mos Ending 4/30/2028	Projected* 28 Mos Ending 4/30/2028
8	Fleet Vehicle Capital Replacement	1,579	22,015	20,868	44,462
9	Fleet Capital Replacement - Additional	0	33,150	0	33,150
10	Fleet Vehicle Electrification	0	1,040	500	1,540
11	Fleet Expansion	0	18,139	5,000	23,139
12	Fleet Business Partner Funded	0	0	0	0
13	Fleet Tools - Garage	86	259	265	610
14	Total Fleet Services Capital	1,665	74,603	26,633	102,901

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Fleet Services
($000)

Case No.: U-22070
Exhibit No.: A-12 (JJJ-1)
Schedule: B-5.1
Page: 2 of 3
Witness: JJJudy
Date: June 2026

Line No	Description	Historical Year 12 Mos Ended 12/31/2025	Projected Bridge Year* 12 Mos Ending 12/31/2026	Projected Bridge Year* 4 Mos Ending 4/30/2027	Projected Bridge Year* 16 Mos Ending 4/30/2027	Projected* Test Year 12 Mos Ending 4/30/2028
	(a)	(b)	(c)	(d)	(e)	(f)
1	**Fleet Vehicle Capital Replacement**	**22,054**	**20,359**	**3,235**	**23,594**	**20,868**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	15,888	16,470	2,617	19,088	16,882
	Contractor	6,077	3,644	579	4,223	3,735
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	89	244	39	283	250
	Contingency	0	0	0	0	0
2	**Fleet Capital Replacement - Additional**	**0**	**33,150**	**0**	**33,150**	**0**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	0	26,818	0	26,818	0
	Contractor	0	5,934	0	5,934	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	398	0	398	0
	Contingency	0	0	0	0	0
3	**Fleet Vehicle Electrification**	**0**	**1,040**	**0**	**1,040**	**500**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	0	0	0	0	0
	Contractor	0	1,040	0	1,040	500
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0
4	**Fleet Expansion**	**856**	**10,905**	**7,234**	**18,139**	**5,000**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	616	8,822	5,852	14,674	4,045
	Contractor	236	1,952	1,295	3,247	895
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	3	131	87	218	60
	Contingency	0	0	0	0	0
5	**Fleet Business Partner Funded**	**734.287**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	529	0	0	0	0
	Contractor	202	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	3	0	0	0	0
	Contingency	0	0	0	0	0
6	**Fleet Tools - Garage**	**271**	**257**	**88**	**345**	**265**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	271	257	88	345	265
	Contractor	0	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0
7	**Total Fleet Services Capital**	**23,915**	**65,711**	**10,557**	**76,268**	**26,633**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	17,304	52,368	8,557	60,925	21,193
	Contractor	6,515	12,570	1,874	14,444	5,130
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	96	773	126	899	310
	Contingency	0	0	0	0	0

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence*
***Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).*

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Fleet Services
($000)

Case No.: U-22070
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	(a)	(b)	(c)	(d)	(e)
		Projected*			
		4 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028	28 Mos Ending 4/30/2028
8	**Fleet Vehicle Capital Replacement**	**1,579**	**22,015**	**20,868**	**44,462**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	1,278	17,810	16,882	35,970
	Contractor	283	3,941	3,735	7,959
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	19	264	250	534
	Contingency	0	0	0	0
9	**Fleet Capital Replacement - Additional**	**0**	**33,150**	**0**	**33,150**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	26,818	0	26,818
	Contractor	0	5,934	0	5,934
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	398	0	398
	Contingency	0	0	0	0
10	**Fleet Vehicle Electrification**	**0**	**1,040**	**500**	**1,540**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	0	0
	Contractor	0	1,040	500	1,540
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
11	**Fleet Expansion**	**0**	**18,139**	**5,000**	**23,139**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	14,674	4,045	18,719
	Contractor	0	3,247	895	4,142
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	218	60	278
	Contingency	0	0	0	0
12	**Fleet Business Partner Funded**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	0	0
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
13	**Fleet Tools - Garage**	**86**	**259**	**265**	**610**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	86	259	265	610
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
14	**Total Fleet Services Capital**	**1,665**	**74,603**	**26,633**	**102,901**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	1,363	59,562	21,193	82,118
	Contractor	283	14,161	5,130	19,574
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	19	880	310	1,209
	Contingency	0	0	0	0

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence*
***Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).*

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Fleet Responsibility Costs

Case No.: U-22070
Exhibit No.: A-143 (JJJ-2)
Page: 1 of 1
Witness: JJJudy
Date: June 2026

Responsibility $'s by Cost Category	Historical	Historical	Historical	Historical	Historical	Projected*	Projected*	Projected* 12 Mos Ending
Categories	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**4/30/2028**
Licensing	2,840,343	3,145,786	3,192,336	3,039,700	3,280,374	3,108,740	3,108,740	3,108,740
Technician	18,902,790	19,788,278	19,585,618	20,577,927	22,730,056	21,253,815	21,443,969	21,443,969
Parts	11,649,547	14,557,200	14,755,428	14,803,380	18,729,184	15,382,195	15,382,195	15,382,195
Outside Vendor	12,801,491	14,875,779	14,242,537	17,803,960	22,986,318	16,675,875	16,675,875	16,675,875
Fuel	17,865,478	25,105,355	20,322,235	19,459,697	19,592,594	16,958,059	16,958,059	16,958,059
Support Labor	5,034,713	5,031,440	4,790,586	4,055,665	4,436,058	4,641,942	4,705,931	4,715,243
Support Other	3,480,793	4,205,239	3,174,534	4,077,349	5,468,081	4,258,461	4,258,461	4,258,461
Total Cost	72,575,154	86,709,077	80,063,275	83,817,677	97,222,665	82,279,088	82,533,230	82,542,542

Estimated Cost Allocation to Business Unit (%)

Business Unit	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**4/30/2028**
BUSTRAN	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%
CORP	0.5%	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%
CUSEXGR	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%
ELDISTR	3.0%	3.2%	3.1%	3.8%	1.9%	1.9%	1.9%	1.9%
ELSUPPLY	2.1%	2.0%	1.9%	2.0%	1.8%	1.8%	1.8%	1.8%
GASDELV	4.9%	5.1%	4.1%	3.7%	3.2%	3.2%	3.2%	3.2%
OPSPLAN	85.8%	85.8%	87.2%	87.1%	89.6%	89.6%	89.6%	89.6%
OPSWRKMGT	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
SHAREDSVCS	2.9%	2.8%	2.6%	2.4%	2.5%	2.5%	2.5%	2.5%

Estimated Cost Allocation to Business Unit ($)

Business Unit	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**4/30/2028**
BUSTRAN	137,226	151,384	121,985	107,112	135,862	114,980	115,335	115,348
CORP	382,308	359,526	302,451	301,536	289,867	245,313	246,070	246,098
CUSEXGR	212,095	262,151	239,621	230,507	171,647	145,264	145,713	145,730
ELDISTR	2,191,115	2,805,312	2,477,398	3,146,860	1,889,784	1,599,315	1,604,255	1,604,436
ELSUPPLY	1,514,272	1,719,626	1,491,829	1,676,711	1,736,103	1,469,256	1,473,794	1,473,961
GASDELV	3,540,807	4,419,231	3,253,719	3,101,830	3,150,351	2,666,127	2,674,362	2,674,664
OPSPLAN	62,237,329	74,356,047	69,834,345	72,998,615	87,150,965	73,755,455	73,983,269	73,991,617
OPSWRKMGT	275,743	247,665	234,574	233,020	245,296	207,593	208,234	208,257
SHAREDSVCS	2,084,259	2,388,137	2,107,352	2,021,487	2,452,790	2,075,785	2,082,197	2,082,432
Total	72,575,154	86,709,077	80,063,275	83,817,677	97,222,665	82,279,088	82,533,230	82,542,542

Estimated O&M & Capital %	OM	Capital
BUSTRAN	50%	50%
CORP	50%	50%
CUSEXGR	50%	50%
ELDISTR	10%	90%
ELSUPPLY	10%	90%
GASDELV	70%	30%
OPSPLAN	24%	76%
OPSWRKMGT	16%	84%
SHAREDSVCS	25%	75%

Estimated O&M ($) by Business Unit

OM	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**4/30/2028**
BUSTRAN	68,613	75,692	60,993	53,556	67,931	57,490	57,667	57,674
CORP	191,154	179,763	151,225	150,768	144,933	122,656	123,035	123,049
CUSEXGR	106,048	131,075	119,811	115,253	85,824	72,632	72,857	72,865
ELDISTR	219,111	280,531	247,740	314,686	188,978	159,932	160,426	160,444
ELSUPPLY	151,427	171,963	149,183	167,671	173,610	146,926	147,379	147,396
GASDELV	2,478,565	3,093,462	2,277,603	2,171,281	2,205,246	1,866,289	1,872,054	1,872,265
OPSPLAN	14,936,959	17,845,451	16,760,243	17,519,668	20,916,232	17,701,309	17,755,985	17,757,988
OPSWRKMGT	44,119	39,626	37,532	37,283	39,247	33,215	33,317	33,321
SHAREDSVCS	521,065	597,034	526,838	505,372	613,198	518,946	520,549	520,608
Total	18,717,061	22,414,597	20,331,167	21,035,538	24,435,199	20,679,395	20,743,269	20,745,609

Estimated Capital ($) by Business Unit

Capital	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**4/30/2028**
BUSTRAN	68,613	75,692	60,993	53,556	67,931	57,490	57,667	57,674
CORP	191,154	179,763	151,225	150,768	144,933	122,656	123,035	123,049
CUSEXGR	106,048	131,075	119,811	115,253	85,824	72,632	72,857	72,865
ELDISTR	1,972,003	2,524,780	2,229,658	2,832,174	1,700,805	1,439,384	1,443,830	1,443,993
ELSUPPLY	1,362,845	1,547,663	1,342,646	1,509,040	1,562,493	1,322,330	1,326,415	1,326,564
GASDELV	1,062,242	1,325,769	976,116	930,549	945,105	799,838	802,309	802,399
OPSPLAN	47,300,370	56,510,595	53,074,102	55,478,948	66,234,733	56,054,146	56,227,285	56,233,629
OPSWRKMGT	231,624	208,038	197,042	195,737	206,048	174,378	174,916	174,936
SHAREDSVCS	1,563,194	1,791,102	1,580,514	1,516,115	1,839,593	1,556,839	1,561,647	1,561,824
Total	53,858,093	64,294,479	59,732,108	62,782,140	72,787,466	61,599,693	61,789,961	61,796,932

Estimated O&M & Capital $	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**4/30/2028**
Total	72,575,153.97	86,709,076.71	80,063,274.82	83,817,677.28	97,222,664.83	82,279,087.51	82,533,229.90	82,542,541.79
OM	26%	26%	25%	25%	25%	25%	25%	25%
Capital	74%	74%	75%	75%	75%	75%	75%	75%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Corporation
Detailed List of Projected Electric Capital Expenditures
Fleet Services
For the Years 2025, 2026, 2027 and test year 12 months ending 04/30/2028
($000)

Case No.: U-22070
Exhibit No.: A-144 (JJJ-3)
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Witness: JJJudy
Date: June 2026

Line No.	(a)	(b)	(c) 12 months ending 12/31/2025 Historical Spend*	(d) 12 months ending 12/31/2025 Historical Unit Count*	(e) 12 months ending 12/31/2026 Projected Spend*	(f) 12 months ending 12/31/2026 Projected Unit Count*	(g) 12 months ending 12/31/2027 Projected Spend	(h) 12 months ending 12/31/2027 Projected Unit Count	*Test Year* (i) 12 months ending 4/30/2028 Projected Spend	(j) 12 months ending 4/30/2028 Projected Unit Count
1	**Fleet Vehicle Capital Replacement Plan**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**22,054**	**238**	**20,359**	**78**	**20,868**	**82**	**20,868**	**112**
	07	SEDAN MID SIZE 4DR	$ -	-	$ -	-	$ 52	1	$ -	-
	10	PU 4WD EXCAB	$ -	-	$ 836	22	$ -	-	$ -	-
	22	1/2 TON PICKUP	$ -	-	$ -	-	$ 182	4	$ 97	2
	23	VAN CARGO	$ 137	2	$ 9	1	$ -	-	$ 177	2
	26	1 TON PICKUP WITH SERVICE BODY SHORT CAB	$ 381	6	$ 151	2	$ -	-	$ -	-
	28	3/4 TON PICKUP	$ 287	13	$ 99	4	$ 1,224	16	$ 2,278	31
	36	1 TON PICKUP WITH SERVICE BODY	$ 1,002	15	$ 181	3	$ -	-	$ 1,353	12
	39	VAN CARGO HI ROOF	$ -	-	$ -	-	$ -	-	$ -	-
	45	MECHANIC SERVICE TRUCK	$ 136	1	$ 140	1	$ 236	1	$ 233	1
	54	5 YARD DUMP TRUCK SINGLE AXLE	$ -	-	$ -	-	$ -	-	$ -	-
	59	STAKE RACK TRUCK	$ -	-	$ -	-	$ 138	1	$ 136	1
	60	ELECTRIC SERVICE TRUCK	$ 634	4	$ 109	2	$ -	-	$ 496	4
	61	TRUCK SVC AERIAL 41' 4WD	$ -	-	$ -	-	$ -	-	$ 550	2
	64	SERVICE TRUCK WITH AERIAL DEVICE	$ 990	-	$ 6,952	24	$ 2,893	10	$ 3,988	22
	65	TRUCK STREETLIGHT	$ -		$ -	-	$ -	-	$ -	-
	66	TRUCK URD CONST/MAINT	$ -		$ -	-	$ -	-	$ -	-
	75	TRUCK DIG/DRK W/FLATBED	$ -		$ -	-	$ -	-	$ -	-
	77	DIGGER DERRICK TRUCK	$ 5,347	16	$ 5,703	11	$ 3,284	12	$ 4,339	11
	85	TANDUM AXLE TRACTOR WITH FIFTH WHEEL HITCH	$ -	-	$ -	-	$ 91	1	$ 90	1
	86	FLATBED / STAKE RACK	$ -	-	$ 144	1	$ -	-	$ -	-
	89	BUCKET TRUCK	$ 1,530	3	$ 2,842	1	$ 8,120	18	$ 5,055	13
	90	FLATBED TRUCK	$ 85	1	$ -	-	$ -	-	$ -	-
	96	BUCKET TRUCK	$ 458	-	$ 2,700	-	$ 4,466	16	$ 1,570	6
	EQUIPMENT	EQUIPMENT	$ 4,625	29	$ 138	3	$ 66	1	$ 292	2
	TRAILERS	TRAILERS	$ 2,049	38	$ 355	3	$ 116	1	$ 214	2
		Lease Buyout - Electric/Common	$ 1,966	64						
		Rental Buyouts	$ 2,427	46						
2	**Fleet Capital Replacement - Additional**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**$ -**	**-**	**$ 33,150**	**83**	**$ -**	**-**	**$ -**	**-**
	89/96	BUCKET TRUCK	$ -	-	$ 33,150	83	$ -	-	$ -	-
3	**Fleet Vehicle Electrification**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**$ -**	**-**	**$ 1,040**	**-**	**$ 500**	**-**	**$ 500**	**-**
	64	SERVICE TRUCK WITH AERIAL DEVICE	$ -	-	$ 1,040	-	$ 500	-	$ 500	-
4	**Fleet Expansion**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**$ 855.57**	**8**	**$ 10,905**	**140**	**$ 12,234**	**36**	**$ 5,000**	**13**
	22	1/2T	$ -	-	$ 168	3	$ -	-	$ -	-
	28	3/4T PICKUP	$ 856	8	$ 3,491	53	$ -	-	$ -	-
	55	10 YARD DUMP	$ -	-	$ -	-	$ 525	3	$ -	-
	42 / 59	FITTING TRUCK	$ -	-	$ 1,000	10	$ -	-	$ -	-
	77	DERRICK TRUCK	$ -	-	$ -	-	$ 2,598	7	$ -	-
	89/96	BUCKET TRUCK	$ -	-	$ -	-	$ 1,279	3	$ -	-
	90	REEL TRUCK	$ -	-	$ -	-	$ 1,754	10	$ -	-
	EQUIPMENT	EQUIPMENT	$ -	-	$ 4,565	32	$ -	-	$ -	-
	TRAILERS	TRAILERS	$ -	-	$ 1,681	42	$ -	-	$ -	-
	Spec 77 Tools	TOOLS	$ -	-	$ -	-	$ 328	-	$ -	-
	Spec 89/96 Tools	TOOLS	$ -	-			$ 750		$ -	-
	64	SERVICE TRUCK W/ AERIAL DEVICE (CFS EXPANSION)	$ -	-	$ -	-	$ 5,000	13	$ 5,000	13
5	**Fleet Business Partner Funded**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**734.287**	**10**	**-**	**-**	**-**	**-**	**-**	**-**
	T10	EQUIPMENT TRAILER	$ 734	10	$ -	-	$ -	-	$ -	-
6	**Totals:**		**23,644**	**256**	**65,454**	**301**	**33,602**	**118**	**26,368**	**125**

**Where there are dollars and no unit counts, this is the chassis portion only. We are only counting a full unit when we receive the unit and it is in use. Common unit costs are divided between Gas and Electric*
***The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.*

Michigan Public Service Commission
Consumers Energy Company
Fleet Services

Case No.: U-22070
Exhibit No.: A-144 (JJJ-3)
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Line No.	(a)	(b)	(c)	(d)
	Project Name	**Internal Approval**	**Has a Business Case**	**Explanation**
1	Fleet Vehicle Capital Replacement Plan	YES	NO	Internal funding approval. There is no formal business case, spending level is at approved historical plus inflation.
2	Fleet Capital Replacement - Additional	YES	YES	
3	Fleet Vehicle Electrification	YES	NO	Internal funding approval. There is no formal business case, spending level supports the Fleet Vehicle Capital Replacement plan plus the additional cost for EV units.
4	Fleet Expansion	YES	YES	Please see the direct testimony of Company witness Samantha Kelly.
5	Fleet Business Partner Funded	YES	NO	Internal funding approval. There is no formal business case but there are internal support documents for individual unit need.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Corporation
Summary of Fleet Tooling Actual & Projected Capital Expenditures
Fleet Services
For the Years 2025, 2026, 2027 and test year 12 months ending 04/30/2028
($000)

Case No.: U-22070
Exhibit No.: A-145 (JJJ-4)
Page: 1 of 1
Witness: JJJudy
Date: June 2026

Line No.	(a)	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected* 12 Mos Ended 12/31/2026	(d) Projected* 12 Mos Ended 12/31/2027	(e) Projected* Test Year 12 Mos Ending 4/30/2028
1	**Fleet Tools - Garage**				
	Tool Description				
	Shop Equipment	$ 223	$ 201	$ 203	$ 203
	Shop Tools	$ 30	$ 28	$ 30	$ 30
	Diagnostic Tools	$ 18	$ 28	$ 30	$ 30
2	**Fleet Tools Totals:**	**$ 271**	**$ 257**	**$ 263**	**$ 263**

*The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.

Exhibit A-146 (JJJ-5)
is Confidential
And Being Filed Under Seal

Impact of Reduced Fleet Purchases

Implications for Cost, Safety, and Reliability (2016–2025)

Purpose and Context

This paper is an analysis based on the Attorney General's recommendation that:

> "The Commission direct the Company to present a thorough plan in the Electric Rate Case that addresses the utilization rate of vehicles and field equipment and the impact of reduced vehicle purchases in future years."

The Company fleet data analyzed (found in Exhibit A-148 (JJJ-7) focused on owned fleet, excluding rental assets that are typically newer, more temporary units. This view is essential for understanding the true long-term fleet status because owned assets carry the full burden of vehicle lifespan cost, safety risk, and reliability exposure. Unlike rentals, owned assets remain on the balance sheet longer, accumulate wear and tear, and require increasing internal maintenance resources as they age. The wear and tear over time may also contribute to higher vigilance to key safety equipment and apparatus, and higher fossil fuel emissions and consumption.

This analysis examines Company fleet data and how the owned fleet has aged over the 2016–2025 period and explains why the aging trend shown in the data is a risk that requires a plan to stabilize fleet aging. The focus on aging is critical as it relates to "reduced vehicle purchases in future years". There is a direct relationship between the number of vehicles purchased, and the direct impact it has on the age of the fleet. Holding on to units that are past the point of their

replacement cycle will continue to progressively age the fleet. This forces the continued use of older units, with the associated challenges of keeping older units safe, functional, and cost effective even as they continue to be utilized.

Further, this analysis contends that the impact of reduced vehicle purchases in future years would be detrimental to the Company's overall fleet. There are potential significant financial, operational, and safety considerations for the Company that must be managed, concluding that reduced vehicle fleet purchases in future years would have a negative impact on the Company's ability to provide safe, reliable, and efficient services to its customers. Lastly, even as unit age increases, average utilization rates over the study period rise or stay stable despite the aging of the fleet, indicating that the Company is extracting more work from an older fleet.

Quantitative Overview of Fleet Aging

The Company's fleet, not including rentals, shows that the average age of the owned fleet ages as follows:

- **2016:** 9.72 years
- **2017:** 9.32 years
- **2018:** 9.26 years
- **2019:** 9.36 years
- **2020:** 9.19 years
- **2021:** 9.30 years
- **2022:** 7.82 years
- **2023:** 8.15 years
- **2024:** 8.40 years
- **2025:** 8.89 years

Fleet Age Trends Higher

- The fleet entered the study period, already very mature, averaging close to 10 years old.
- A temporary reduction in age in 2022 interrupts the trend.
- From 2023 onward, average age rises every year, reaching 8.9 years by 2025.
- The long-term direction is upward, not stable, or declining.

The data shows that based on the current fleet purchase plan the owned fleet is already aging based on current spend levels, averaging about 4.4% per year increase in average age between 2022 and 2025. The current replacement rate has not been sufficient to reverse this trend. It should be noted that the data shows a sharp reduction in average age from 9.30 years in 2021 to 7.82 years in 2022. At first glance, this could be interpreted as a refresh of the fleet. However, while new vehicles were purchased during this period, the disallowance of those purchases resulted in the disposition of many of those new units. Therefore, the influence of newer vehicles on the overall age of the fleet was temporary.

- The reduction in fleet age coincides with a decline in total owned units, indicating removals or disallowance rather than sustained over-replacement.
- Average age could have remained stable in the subsequent years if disallowed units remained in the fleet.
- Average fleet age rises steadily from 2022 through 2025, regaining more than one full year of age in just three cycles.

This pattern indicates that the 2022 reduction in overall aging trend was an anomaly driven by one-time actions, not by an ongoing replacement strategy that keeps a more sustainable mix of vehicle lifecycles.

Long-Term Aging Trend of the Fleet

When rentals are excluded, the aging rate is concerning:

- In seven out of 10 years, the owned fleet averages above 9 years.
- Even after the 2022 reduction, the fleet quickly rebounds toward that level.
- By 2025, the owned fleet is once again approaching 9 years average age, placing a sizable portion of assets well beyond midlife.

Drivers of Aging

1. **Historical Spend**
   The current Fleet Replacement Plan is limited to the currently approved historical plus inflation budget.
2. **Replacement Lag**
   Annual acquisitions are insufficient to offset natural aging of the installed base. Production units take about two years from order to delivery.
3. **Long-Lived Asset Classes**
   Even accounting for specialty equipment, shop units that remain in service longer than a typical light-duty asset, there is an aging trend for critical production units like bucket and pick-up trucks.

Impact on Fleet Cost

Rising Maintenance and Repair Costs

As assets age, maintenance costs can increase non-linearly. Older equipment often requires:

- More frequent preventive maintenance.
- Higher corrective maintenance due to part failures.
- Longer shop visits and higher labor hours per event.
- Potential delays as parts for older vehicles may become obsolete.

With an average age of nearly 9 years, a sizable portion of the owned fleet will cost more to maintain as they approach the end of their lifecycle.

Even if annual maintenance budgets appear stable, cost per unit inevitably increases because:

- Parts availability declines for older models potentially delaying repairs or increasing the cost of the parts.
- Mechanic's labor hours rise.
- Planned maintenance is supplemented by unplanned repairs.

The data for Company owned vehicles strongly suggests that maintenance cost pressure is inherent in the purchase plan and growing, not a short-term concern.

Fleet Purchase Plan Limitations

The effect of the current fleet replacement plan does not allow the Company to keep pace with the number of vehicles that are approaching or have reached their end of lifecycle. The result can mean increased operating expenses over time to keep older vehicles safe and operational even as their utilization continues. The risk of increased exposure to large, unplanned repair events and cost increases associated with older vehicles and equipment rises. The steady rise in average age from 2023 to 2025 indicates that the organization is accumulating future capital risk, even if annual budgets stay consistent.

Increasing Total Cost of Ownership

As fleet age increases:

- Depreciation of efficiency declines.
- Maintenance costs per mile/hour rise.
- Downtime-related costs (lost productivity, backup equipment) increase.

- Potential for unpredictable repairs rise (e.g. in field breakdowns)

The cost data for Company many owned vehicles and equipment shows that the owned fleet spends extended time beyond optimal economic life, highlighted by the costs associated with maintaining some units as they approach the 8 to 10 years in service range.

Impact on Reliability

Reliability deteriorates as assets age due to:

- Component fatigue (chassis and body degradation).
- Unpredictable parts failures (e.g. belts, hoses, transmission failures etc.)
- Obsolescence of electronics and controls.

With average age hovering near 9 years, a growing share of the owned fleet is statistically more likely to experience:

- Breakdown events.
- Safety related concerns.
- Major component failures including engine, transmission, boom, and upfit equipment.
- Cascading component damage.

This raises not only maintenance costs, but also potential serious operational disruptions. For example, in February 2026, there was a catastrophic boom tip failure occurring on a 2015 Terex TL-55 bucket truck in Flint. The deployed bucket, with two men in it, partially detached and overturned, suspending the linemen in mid-air attached to their safety tethers. At the time of the incident, the truck in question was 11 years old, had reached the Blended Factor threshold for replacement, and was already planned for replacement in 2026.

Downtime and Availability Risk

Older fleets tend to experience:

- Longer repair-cycle times.
- Increased parts back-order delays for increasingly hard to find parts.
- Reduced interchangeability with newer systems.

From an operational standpoint, aging reduces asset availability, with a higher probability of unpredictable emergent repairs that can occur between preventative maintenance schedules. This includes engine and transmission failure replacements that can bring older units down, and increases reliance on:

- Spare units
- Short-term rentals

The fact that this analysis excludes rentals makes the reliability warning even stronger: the core fleet is aging, forcing the Company to rely on deploying its workforce in aging critical units that are experiencing increasing wear and tear, reliability and safety concerns, and rising maintenance costs during a critical period in infrastructure improvement planning in addition to ongoing storm restorations.

Reliability Variability Across Units

As age distribution widens, reliability becomes:

- Less predictable: increasing odds of in the field breakdowns or failures.
- More dependent on unit-by-unit condition inspections.
- More difficult to manage through standardized maintenance programs.

This variability strains planning, scheduling, and shop workload.

Impact on Safety & Mechanical Safety Risk

Aging equipment increases the likelihood of:

- Brake systems degradation.
- Steering and suspension failures.
- Hydraulic or electrical system faults.
- Body, upfit, frame and sub-frame corrosion.

Even with rigorous regular (preventative maintenance) inspections, older equipment has narrower safety margins due to cumulative wear. The aging trends shown by the data imply the potential for increasing number of assets that are operating (or will operate) closer to minimum acceptable condition, which is not optimal for the safety conditions to serve customers or for the safety of the Company's crews.

Technology Obsolescence

Older owned assets often lack:

- Improved modern safety features that newer vehicles offer.
- Advanced diagnostics.
- Electronic stability or operator-aid systems Advanced Driver-Assistance Systems (known as ADAS) that are becoming increasingly available in vehicles even with commercial fleet specifications.

As the average age increases, the fleet becomes less aligned with current safety standards, even if it remains legally compliant. This increases organizational exposure to:

- Injury risk.
- Incident severity.
- Liability and reputational impact from the Company's workforce.

Human-Factor Risk

Older equipment:

- Requires more manual intervention.
- Usually, they have less ergonomic designs or have worn components like driver seats.
- Creates higher operator workload during failure, or delays in scheduling as malfunctioning vehicles require moving crews into spares when available.

These factors elevate the risk of operator error and fatigue-related incidents, particularly during breakdowns or emergency situations.

The workforce expects that the Company will provide fleet units that are safe and reliable tools engaged to perform the work required, often under challenging situations and conditions, especially during storm restoration.

Operational and Strategic Consequences

When fleet aging is gradual, organizations often defer action. However, once enough assets approach end-of-life simultaneously, replacement decisions can shift from strategic to reactive. This can result in:

- Compressed capital funding needs
- Reduced procurement leverage
- Higher per-unit acquisition cost

The upward trend after 2022 serves as a signal that future replacement challenges are developing.

Strategic Implications and Takeaways

Key Conclusions

1. The owned fleet is inherently aging, not temporarily fluctuating.
2. Aging directly increases cost, downtime, safety exposure, and reliability risk.
3. Current rate of 1:1 replacement cannot keep pace with fleet aging trends.
4. Without intentional intervention, fleet's average age will continue trending upward.

Final Assessment

The Company's fleet data suggests that the fleet is on course to continue aging at current level of spending. Planning for a systematic future reduction of fleet purchases would have a detrimental impact on fleet's ability to support Reliability Work Plan projects that will require a robust fleet for the grid enhancements planned over the next decade. Additionally, the average utilization data suggests that vehicles continue to be used despite being in the latter stages of their lifespans. There is a sizable portion of the Company's fleet that is at or nearly past its optimal point. Since the current underlying trend shows that replacement levels are insufficient to counteract natural aging, it would not be prudent to plan any significant *reduction* in total units. In fact, it is the opposite, fleet should be planning to *lower the average age* of critical production vehicles, like service bucket trucks, which have long lead times of one and a half to two years to build. Delaying the replacement of older bucket trucks could exacerbate the overall aging for these units as the Company waits for their replacements to be delivered.

Left unaddressed, this trajectory will result in:

- Escalating maintenance cost.
- Increased unplanned downtime due to worn engines, transmissions, etc.

- Higher safety and liability exposure such as the recent boom tip failure.
- Larger, more disruptive unplanned capital requirements in the future.

From a fleet management perspective, the data supports a shift toward an accelerated, multi-year, expanded 1:1 replacement planning process, designed to replace old units that intentionally reduce overall average fleet age.

Regarding the correlation between reduced fleet purchases and utilization rates, the data suggests that even as key fleet assets age, their utilization actually rises over the study period, like specs 64, 89, and 96 bucket trucks for example. Lowering fleet purchases for this group would actually exacerbate fleet aging and increase maintenance costs as the Company would rely even more on an aging fleet. Therefore, it is the conclusion of this analysis that it would not be prudent to intentionally *reduce* fleet purchases in the future as its impact on the electric and gas services, grid improvements and storm restoration work the Company provides customers may be compromised in future years.

	2016			2017			2018			2019			2020			2021			2022			2023			2024			2025			Average Unit Age
Row Labels	Count	Average of UnitAge	Average Utilization	Count of Equipment	Average of UnitAge	Average Utilization	Count of Equipment	Average of UnitAge	Average Utilization	Count of Equipment	Average of UnitAge	Average Utilization	Count of Equipment	Average of UnitAge	Average Utilization	Count of Equipment	Average of UnitAge	Average Utilization	Count of Equipment	Average of UnitAge	Average Utilization	Count of Equipment	Average of UnitAge	Average Utilization	Count of Equipment	Average of UnitAge	Average Utilization	Count of Equipment	Average of UnitAge	Average Utilization	
FL06	163	4.52	N/A	161	5.38	N/A	159	4.82	N/A	163	4.64	N/A	156	5.51	N/A	143	6.27	29%	124	7.60	32%	112	8.25	28%	108	9.14	28%	102	9.90	27%	6.29
FL07	66	5.68	N/A	67	6.58	N/A	102	4.19	N/A	177	2.31	N/A	271	1.94	N/A	286	2.47	49%	269	3.26	53%	241	4.06	53%	236	4.64	58%	235	5.57	61%	3.66
FL22	536	6.07	N/A	531	6.66	N/A	517	7.27	N/A	504	7.63	N/A	632	6.25	N/A	577	6.41	51%	562	6.70	52%	529	7.08	53%	517	6.92	52%	502	7.72	53%	6.84
FL23	553	6.78	N/A	552	6.67	N/A	520	6.38	N/A	503	7.18	N/A	548	6.35	N/A	522	6.44	59%	513	6.44	61%	500	6.82	62%	497	7.00	61%	480	7.46	59%	6.74
FL26			N/A	5	0.80	N/A	5	1.80	N/A	7	2.57	N/A	9	3.00	N/A	25	2.12	65%	47	1.87	63%	47	2.87	65%	52	3.60	65%	62	4.02	66%	2.97
FL27	83	4.87	N/A	92	5.08	N/A	91	5.97	N/A	106	5.72	N/A	119	5.71	N/A	134	5.37	65%	148	5.71	70%	141	6.20	69%							5.62
FL27A			N/A			N/A			N/A			N/A			N/A										20	8.10	69%	26	6.58	53%	7.24
FL27B			N/A			N/A			N/A			N/A			N/A										128	6.49	65%	138	6.67	66%	6.59
FL28	627	7.57	N/A	603	7.38	N/A	611	7.44	N/A	630	6.61	N/A	641	6.76	N/A	732	5.68	54%	712	5.77	59%	699	6.46	59%	695	7.06	59%	708	7.63	57%	6.81
FL29			N/A			N/A			N/A			N/A			N/A													1	7.00	0%	7.00
FL36	91	5.56	N/A	86	5.81	N/A	84	6.64	N/A	86	6.83	N/A	98	5.46	N/A	113	4.64	58%	109	5.40	64%	105	5.86	66%	102	6.64	63%	110	6.39	62%	5.89
FL37	44	3.18	N/A	44	4.18	N/A	44	5.18	N/A	42	6.10	N/A	42	7.10	N/A	41	8.00	66%	42	8.50	63%	40	9.25	68%	39	10.13	72%	38	10.97	67%	7.15
FL39	4	5.50	N/A	4	6.50	N/A	4	7.50	N/A	5	4.40	N/A	5	5.40	N/A	18	2.06	27%	19	3.00	29%	22	3.59	28%	22	4.59	27%	22	5.59	35%	4.19
FL40	3	10.00	N/A	3	11.00	N/A	1	12.00	N/A	1	13.00	N/A			N/A																11.00
FL41	93	8.01	N/A	92	8.26	N/A	90	8.59	N/A	85	9.01	N/A	86	9.31	N/A	85	9.88	56%	82	8.76	56%	79	9.51	59%	59	8.32	63%	59	8.63	65%	8.83
FL42	36	5.36	N/A	33	5.67	N/A	31	6.13	N/A	30	6.87	N/A	30	7.87	N/A	32	8.38	73%	32	8.88	71%	33	9.91	73%							7.36
FL42A			N/A			N/A			N/A			N/A			N/A										29	11.86	79%	29	12.86	74%	12.36
FL42B			N/A			N/A			N/A			N/A			N/A										4	4.00	65%	7	2.86	58%	3.27
FL43	16	1.19	N/A	16	2.19	N/A	16	3.19	N/A	18	3.72	N/A	20	4.25	N/A	20	5.25	59%	22	5.32	57%	22	6.32	52%	22	7.32	53%	22	8.32	51%	4.96
FL44	149	6.70	N/A	141	7.23	N/A	143	5.62	N/A	143	6.44	N/A	142	7.39	N/A	140	8.19	58%	152	7.50	54%	145	6.61	55%	145	7.48	56%	144	6.97	55%	7.01
FL45	37	7.19	N/A	36	7.47	N/A	41	6.90	N/A	41	6.68	N/A	42	7.07	N/A	41	7.80	46%	43	7.98	45%	43	8.74	44%	46	9.11	40%	45	9.33	39%	7.87
FL46	1	15.00	N/A	1	16.00	N/A	1	17.00	N/A	1	18.00	N/A	1	19.00	N/A										4	17.75	1%	4	18.75	1%	17.77
FL54	65	3.60	N/A	64	4.64	N/A	85	4.07	N/A	88	4.90	N/A	88	5.69	N/A	101	6.30	61%	98	7.06	56%	130	7.52	63%	130	8.26	65%	130	9.26	63%	6.53
FL55	2	1.00	N/A	2	2.00	N/A	2	3.00	N/A	3	2.67	N/A	3	3.67	N/A	4	3.50	8%	5	3.40	12%	6	3.50	29%	13	5.00	45%	14	5.79	44%	4.24
FL57	14	11.57	N/A	13	11.54	N/A	10	9.10	N/A	10	10.10	N/A	18	4.11	N/A	17	3.88	21%	17	4.76	20%	17	5.76	20%	17	6.76	17%	17	7.76	19%	7.13
FL58	12	5.33	N/A	11	5.55	N/A	10	5.60	N/A	10	6.60	N/A	10	7.60	N/A	10	8.60		10	9.60											6.92
FL59	81	5.17	N/A	81	5.85	N/A	81	6.59	N/A	85	7.24	N/A	86	7.48	N/A	97	7.71	41%	120	7.40	42%	117	8.18	50%	116	9.12	49%	115	10.08	48%	7.66
FL60	36	7.97	N/A	34	8.47	N/A	33	9.27	N/A	38	5.82	N/A	39	5.62	N/A	37	6.16	62%	50	3.80	59%	50	4.80	63%	50	5.80	62%	53	6.25	60%	6.19
FL64	103	4.08	N/A	100	4.96	N/A	109	3.69	N/A	107	4.50	N/A	121	4.40	N/A	138	3.80	55%	130	4.52	65%	134	4.91	64%	127	5.32	68%	127	6.13	69%	4.65
FL65	8	5.25	N/A	8	6.25	N/A	7	6.71	N/A	7	7.71	N/A	7	8.71	N/A	7	7.71	48%	7	8.71	46%	7	9.71	45%	7	10.71	43%	7	11.71	40%	8.25
FL66	3	3.67	N/A	3	4.67	N/A	3	5.67	N/A	3	6.67	N/A	3	7.67	N/A	3	8.67	29%	3	9.67	20%	3	10.67	10%	3	11.67	10%	3	12.67	8%	8.17
FL67	4	12.75	N/A	4	13.75	N/A	4	14.75	N/A	4	15.75	N/A	5	13.40	N/A	5	14.40	11%	6	12.83	5%	5	10.60	17%	4	6.75	22%	4	7.75	16%	12.33
FL68	69	1.99	N/A	69	2.99	N/A	69	3.99	N/A	69	4.99	N/A	69	5.99	N/A	69	6.99	75%	69	7.99	70%	69	8.99	72%	72	10.08	72%	72	11.08	70%	6.54
FL75	29	6.21	N/A	28	6.61	N/A	27	7.48	N/A	25	8.36	N/A	21	9.10	N/A	18	9.78	45%	15	10.67	39%	14	11.64	46%	14	12.64	42%	13	13.31	30%	8.90
FL77	102	5.30	N/A	102	6.27	N/A	101	7.16	N/A	105	7.27	N/A	116	6.51	N/A	134	6.05	66%	135	5.69	62%	133	6.23	68%	131	7.12	66%	142	7.11	63%	6.47
FL81			N/A			N/A			N/A			N/A			N/A										1	0.00		1	1.00	4%	0.50
FL82	39	5.87	N/A	37	6.32	N/A	38	7.13	N/A	33	8.06	N/A	28	8.57	N/A	22	8.45	52%	17	8.41	45%	17	9.41	51%	17	10.41	54%	17	11.41	50%	7.92
FL83	4	10.25	N/A	4	11.25	N/A	30	1.63	N/A	30	2.63	N/A	30	3.63	N/A	30	4.63	41%	30	5.63	33%	29	6.00	29%	29	7.00	37%	29	8.00	38%	5.06
FL84			N/A			N/A			N/A			N/A			N/A										4	9.00	47%	4	10.00	46%	9.50
FL85	60	3.25	N/A	73	3.40	N/A	75	4.28	N/A	80	5.10	N/A	83	5.81	N/A	82	6.71	28%	95	6.82	28%	93	7.59	29%							5.55
FL85A			N/A			N/A			N/A			N/A			N/A										37	8.14	27%	37	9.11	30%	8.62
FL86A			N/A			N/A			N/A			N/A			N/A										46	8.46	34%	46	9.46	36%	8.96
FL86B			N/A			N/A			N/A			N/A			N/A										10	6.00	35%	10	7.00	44%	6.50
FL88	5	21.40	N/A	5	22.40	N/A	5	23.40	N/A	5	24.40	N/A	4	25.50	N/A	4	26.50		2	27.50											24.03
FL89	120	1.67	N/A	119	2.06	N/A	126	2.76	N/A	138	3.42	N/A	148	3.95	N/A	150	4.83	63%	159	5.16	61%	159	6.21	64%	158	7.19	64%	159	7.99	64%	4.73
FL90	60	3.97	N/A	67	4.12	N/A	73	4.75	N/A	72	5.58	N/A	72	6.58	N/A	72	7.32	42%	82	6.96	35%	81	7.53	41%	80	8.38	44%	81	9.26	43%	6.57
FL94	11	4.45	N/A	9	2.22	N/A	8	1.63	N/A	8	2.63	N/A	8	3.63	N/A	8	4.63	63%	8	5.63	60%	8	6.63	57%	8	7.63	63%	8	8.63	63%	4.73
FL95	1	16.00	N/A			N/A			N/A			N/A			N/A																16.00
FL96	114	9.15	N/A	100	9.94	N/A	84	10.64	N/A	74	9.32	N/A	86	5.55	N/A	90	4.56	66%	91	3.78	66%	96	4.46	71%	95	5.37	71%	94	6.28	72%	6.90
FL97	3	10.33	N/A	2	9.00	N/A	2	10.00	N/A	2	11.00	N/A	2	12.00	N/A	1	7.00	71%	1	8.00	58%	1	9.00	72%	1	10.00	41%	1	11.00	62%	10.00
FL98	15	9.07	N/A	13	9.31	N/A	13	10.31	N/A	12	10.67	N/A	8	7.50	N/A	8	8.50	7%	9	8.44	4%	6	8.67	8%	6	9.67	7%	6	10.67	7%	9.34
FLCUBEVA	4	4.75	N/A	4	5.75	N/A	4	6.75	N/A	4	7.75	N/A	4	8.75	N/A	4	6.00	34%	4	7.00	49%	4	8.00	51%							6.84
FLE11A	56	3.70	N/A	57	4.11	N/A	65	4.65	N/A	65	5.62	N/A	69	5.46	N/A	67	6.40	8%	57	7.81	8%	57	8.74	8%	61	10.18	8%	62	11.00	7%	6.75
FLE11B	104	6.87	N/A	87	6.44	N/A	117	5.30	N/A	111	5.62	N/A	109	5.17	N/A	110	6.26	11%	81	6.68	14%	81	7.64	16%	80	8.26	14%	79	8.59	14%	6.54
FLE11C	47	9.15	N/A	45	9.89	N/A	41	10.90	N/A	33	11.52	N/A	28	9.11	N/A	29	7.83	3%	29	8.86	5%	29	8.72	6%	13	6.46	5%	23	6.91	10%	9.26
FLE12	26	19.08	N/A	30	17.40	N/A	30	18.40	N/A	30	19.40	N/A	33	18.58	N/A	39	16.72		41	16.90		44	20.20		44	18.61		44	19.61		18.51
FLE20	160	6.93	N/A	156	7.35	N/A	151	8.15	N/A	160	8.53	N/A	163	9.14	N/A	149	9.89	27%	132	10.62	28%	126	10.11	28%	121	10.79	29%	121	11.79	29%	9.19
FLE23	14	35.79	N/A	17	15.24	N/A	17	16.24	N/A	18	15.17	N/A	15	15.87	N/A	15	16.87	8%	15	17.87	9%	15	16.80	9%	14	14.64	10%	14	15.64	14%	17.82
FLE25	26	2.58	N/A	26	3.58	N/A	31	4.06	N/A	29	5.07	N/A	29	6.07	N/A	29	7.07	36%	29	8.07	30%	27	9.07	30%	22	10.14	34%	20	10.60	37%	6.45
FLE26	24	4.75	N/A	29	5.14	N/A	29	6.10	N/A	35	5.91	N/A	37	6.59	N/A	37	7.59	16%	37	8.51	17%	42	8.17	19%	42	9.17	22%	49	9.08	24%	7.37
FLE30	50	16.04	N/A	60	15.00	N/A	63	16.07	N/A	57	11.63	N/A	51	12.18	N/A	48	12.83	12%	35	13.06	19%	26	11.77	13%	20	13.10	19%	20	14.10	18%	12.38
FLE36	99	2.28	N/A	185	2.12	N/A	237	2.73	N/A	250	3.62	N/A	255	4.53	N/A	281	5.10	39%	279	6.12	42%	293	6.73	44%	317	7.30	43%	327	8.00	40%	5.30
FLE43	71	7.35	N/A	71	8.35	N/A	72	8.58	N/A	71	9.11	N/A	71	10.11	N/A	70	11.03	0%	64	12.28	0%	69	12.03	2%	66	12.82	7%	66	13.82	7%	10.48
FLE53			N/A			N/A			N/A			N/A			N/A										19	17.05	3%	16	18.63	4%	17.77
FLE59			N/A			N/A			N/A			N/A			N/A										3	21.00	1%	3	22.00	0%	21.50
FLE60	156	19.24	N/A	157	18.21	N/A	151	18.52	N/A	166	17.20	N/A	183	15.72	N/A	196	14.42	23%	186	15.03	27%	185	13.21	18%	193	12.37	26%	194	12.88	23%	15.47
FLE67	7	15.71	N/A	7	16.71	N/A	7	17.71	N/A	6	15.00	N/A	6	11.17	N/A	8	9.25	4%	8	10.25	7%	7	9.71	6%	7	10.71	9%	7	11.71	11%	12.70
FLE72			N/A			N/A			N/A			N/A			N/A										3	12.67		3	13.67		13.17
FLE73	12	7.17	N/A	13	6.38	N/A	15	6.53	N/A	21	5.95	N/A	21	6.95	N/A	21	7.95	23%	19	7.63	22%	19	8.63	22%	22	9.68	22%	22	10.68	25%	7.90
FLE76	5	10.20	N/A	4	6.25	N/A	4	7.25	N/A	4	8.25	N/A	4	9.25	N/A	4	10.25		4	11.25		2	7.00		2	8.00		2	9.00		8.83
FLE77			N/A	2	1.00	N/A	2	2.00	N/A	3	2.00	N/A	3	3.00	N/A	3	4.00	38%	3	5.00	56%	3	6.00	43%	3	7.00	55%	3	8.00	48%	4.44
FLE78	5	9.60	N/A	5	10.60	N/A	5	11.60	N/A	5	12.60	N/A	5	13.60	N/A	5	14.60	14%	3	19.00	43%	3	20.00	22%	33	7.64	14%	33	8.15	16%	9.81
FLE79	52	1.96	N/A	64	2.69	N/A	85	3.02	N/A	92	3.83	N/A	92	4.83	N/A	91	5.78	28%	99	5.75	27%	94	6.63	30%	97	7.39	33%	91	8.03	32%	5.24
FLE80	12	12.83	N/A	17	8.35	N/A	22	7.82	N/A	22	8.82	N/A	21	7.00	N/A	29	4.11	10%	28	5.07	12%	28	6.07	13%							6.94
FLE82			N/A			N/A			N/A			N/A			N/A	4	1.75	9%	5	2.40	9%	5	3.40	14%	16	5.13	24%	16	6.13	23%	4.70
FLE90	55	7.07	N/A	67	5.81	N/A	68	6.71	N/A	77	6.99	N/A	78	7.91	N/A	78	8.60	5%	74	9.42	7%	83	10.29	7%	85	10.99	8%	87	11.15	9%	8.66
FLE93	9	28.89	N/A	9	20.67	N/A	9	21.67	N/A	9	18.33	N/A	12	13.75	N/A	13	13.77	0%	13	13.38	5%	13	12.00	2%	13	13.00	6%	14	8.36	7%	15.49
FLE95A	27	16.67	N/A	28	16.61	N/A	28	17.61	N/A	33	16.15	N/A	35	16.86	N/A	36	17.11	6%	96	10.72	5%	95	11.62	7%	99	11.69	5%	104	10.74	6%	13.00
FLE96	3	15.33	N/A	5	14.20	N/A	5	15.20	N/A	6	13.50	N/A	6	14.50	N/A	5	13.60		5	14.60		5	15.60		5	16.60		4	15.75		14.82
FLE99	4	6.25	N/A	5	6.00	N/A	13	3.62	N/A	14	4.36	N/A	15	4.00	N/A	18	4.78	9%	16	5.13	9%	16	6.13	11%							4.84
FLEMISC			N/A			N/A			N/A			N/A			N/A										17	11.06	0%	35	6.37	6%	7.90
FLERAMP			N/A			N/A			N/A			N/A			N/A										4	9.50		4	10.50		10.00
FLTCURTA	6	6.17	N/A	6	7.17	N/A	6	8.17	N/A	6	9.17	N/A	6	10.17	N/A	6	11.17		6	12.17		6	13.17		6	14.17		6	15.17		10.67
FLTDRYVA	176	8.41	N/A	183	8.96	N/A	185	9.50	N/A	190	10.23	N/A	196	10.45	N/A	192	11.05		187	11.41		206	10.38		225	10.55		224	11.42		10.28
FLTDUMP			N/A	3	0.00	N/A	3	1.00	N/A	4	1.50	N/A	4	2.25	N/A	4	3.25		4	4.25		2	1.50		4	4.00		4	4.75		2.69
FLTEQUIP	1000	10.40	N/A	1108	8.06	N/A	1216	7.79	N/A	1317	7.48	N/A	1313	7.77	N/A	1313	8.39	1%	1244	8.74	1%	1195	9.32	2%	948	8.16		963	8.94		8.46
FLTFLATBE	23	3.61	N/A	23	4.61	N/A	23	4.91	N/A	23	5.91	N/A	24	6.67	N/A	23	6.65		23	7.65		23	8.65		23	9.65		23	10.65		6.90
FLTFLSHARW			N/A			N/A			N/A			N/A			N/A										9	18.00	0%	8	18.13	0%	18.06
FLTLIGHT			N/A			N/A	1	4.00	N/A	5	2.80	N/A	6	4.17	N/A	6	5.17		6	6.17		16	6.88		43	10.63		43	11.63		9.35
FLTMISC			N/A			N/A			N/A			N/A			N/A										20	20.05		21	20.05		20.05
FLTOILFIL1	20	30.40	N/A	20	25.70	N/A	20	26.70	N/A	20	27.70	N/A	20	28.70	N/A	19	29.63	0%	17	28.94	0%	16	29.69	0%							28.38
FLTOILFLTR			N/A			N/A			N/A			N/A			N/A										40	24.55	2%	42	23.64	2%	24.09
FLTRPE	44	7.41	N/A	44	8.41	N/A	45	9.22	N/A	56	8.41	N/A	57	9.25	N/A	55	9.69		52	10.79		52	11.75		65	11.08		63	11.73		9.89
FLTPOLE	108	10.31	N/A	107	11.31	N/A	99	11.96	N/A	97	12.96	N/A	95	13.81	N/A	89	14.80		69	15.49		91	11.34		88	9.58		92	6.91		11.74
FLTPULLEI	22	10.27	N/A	22	10.55	N/A	21	11.29	N/A	21	12.29	N/A	21	13.29	N/A	20	13.10	1%	21	13.48	1%	19	13.74	1%	19	13.89	6%	27	8.41	6%	11.87
FLTREEL	117	15.31	N/A	116	16.24	N/A	111	16.94	N/A	109	17.86	N/A	106	18.68	N/A	106	19.51		102	17.86		108	15.05		107	9.29		106	9.74		15.65
FLTSECUR			N/A			N/A			N/A			N/A			N/A										5	6.00		11	3.73		4.44
FLTSHORE			N/A			N/A			N/A			N/A			N/A										1	30.00					30.00
FLTSUBRE	6	31.33	N/A	6	21.50	N/A	6	22.50	N/A	6	23.50	N/A	6	24.50	N/A	6	25.50		6	26.50		6	27.50								25.35
FLTSUBRECV			N/A			N/A			N/A			N/A			N/A										30	20.50		29	21.31		20.90
FLTTANKEI	7	6.14	N/A	9	5.78	N/A	11	5.55	N/A	11	6.55	N/A	11	7.55	N/A	11	8.55	8%	7	9.86	4%	6	11.00	5%	21	13.71		21	14.71		9.89
FLTTAPPIN	7	7.57	N/A	7	8.57	N/A	7	9.57	N/A	7	10.57	N/A	7	11.57	N/A	7	13.14		7	14.14		6	12.67		7	11.86		7	12.86		11.23
FLTTENSIC	32	15.34	N/A	31	16.35	N/A	33	16.30	N/A	33	17.30	N/A	32	17.91	N/A	36	16.61		32	16.34		39	8.67		36	8.67		27	10.07		14.27
FLVACUUI	12	16.83	N/A	12	12.17	N/A	12	12.33	N/A	8	13.50	N/A	8	14.50	N/A	8	15.50	6%	7	16.43	6%	4	11.25	6%							14.14
LOCOMOT	6	23.67	N/A	6	24.67	N/A	6	25.67	N/A	6	26.67	N/A	7	23.71	N/A	7	24.71		6	18.33		3	11.67								23.15
SHOP UNI	157	82.55	N/A	157	83.00	N/A	158	83.45	N/A	159	85.42	N/A	159	86.42	N/A	159	86.62														84.62
Grand Tota	6234	9.72	N/A	6425	9.32	N/A	6689	9.26	N/A	6949	9.36	N/A	7320	9.19	N/A	7472	9.30	48%	7193	7.82	49%	7102	8.15	51%	7019	8.40	51%	7104	8.89	51%	8.93

Assessment of Fleet Electrification Viability

Consumers Energy Fleet Purchase Plan Vehicle Electrification

Purpose and Methodology

The purpose of this analysis is to:

> "Provide an assessment of the viability of using electric vehicles for all already scheduled light-duty vehicle replacements between now and 2030."

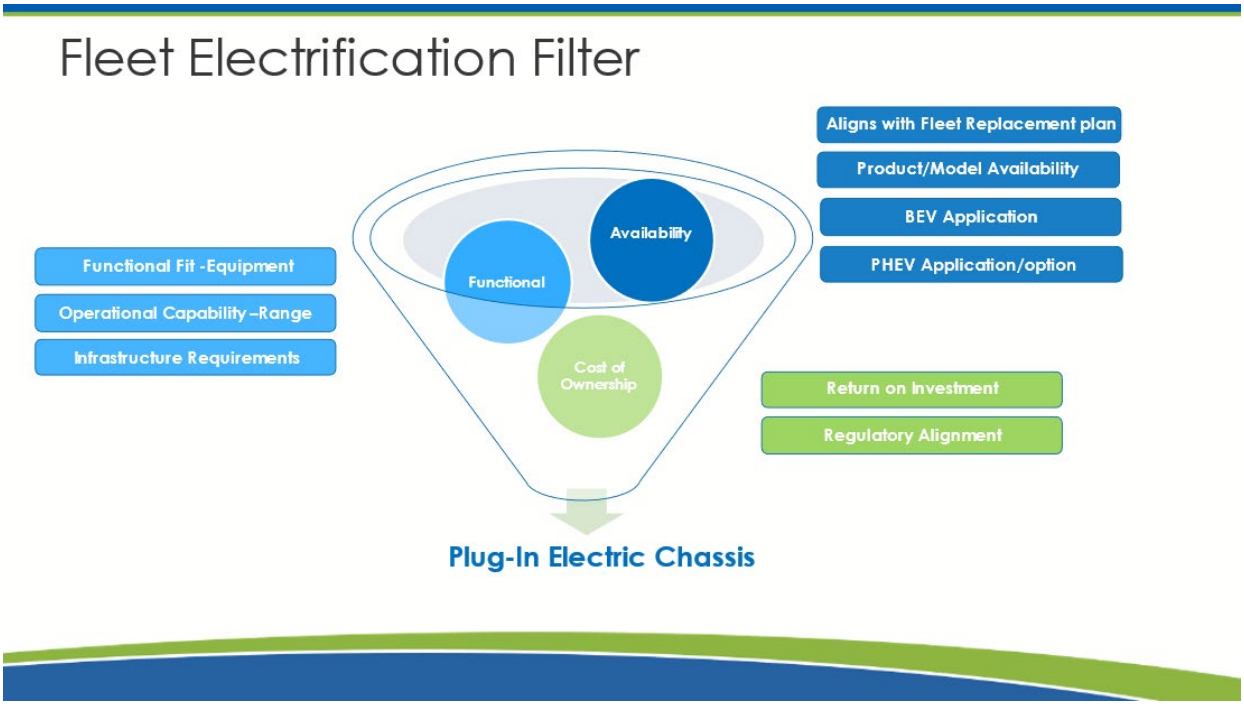
This following paper discusses the technical and operational viability of replacing Internal Combustion Engine powertrains ("ICE") fleet vehicles with a vehicle of similar function but with an electric vehicle ("EV") powertrain in the light duty class (class one and two). As requested, the units under consideration are all light duty units identified for replacement now through 2030. These units mostly include sedans, sport utility vehicles, and pick-up trucks that support various departments and operations. This assessment additionally includes a discussion regarding market availability of EVs for the purposes of fitness and functionality in the Company's fleet as this is critical to viability when comparing the needs of Company fleet support and the reality of what is available to replace an ICE unit with an EV without sacrificing fleet support.

The Company prefers to support Michigan-based auto manufacturers when considering replacing an ICE vehicle with an EV whenever possible. Even so, there are many EVs that are not built

with a commercial fleet/support design, and therefore are usually higher purchase costs associated with more luxury type appointments not suitable to support the work (leather seats, expensive alloy wheels and tires, etc.). The Company strives to acquire EVs that can support the work while limiting the appointments and features that can raise purchase prices or can present maintenance challenges in the future.

Rather than evaluating vehicles through theoretical EV benchmarks (range specs, OEM stated ranges, or best-case assumptions), this review prioritizes:

- Observed mileage patterns
- Tooling, payload, and upfit requirements
- Geographic and duty-cycle realities
- Market availability of fit-for-purpose EV replacements
- EV trials already conducted by the organization



Vehicles were assessed by category (sedans, SUVs, pick-ups, and vans), then cross-referenced with key considerations that would support replacement of an ICE unit with an EV unit. The Fleet Electrification Filter vehicle requirements (see below) outlines key defined attributes considered by fleet stakeholders. In short, electrification decisions must be made pragmatically, not ideologically.

Fleet Composition Overview

The units in the purchase plan are dominated by fleet pick-up trucks and vans, with a smaller number of sedans and SUVs.

Broadly, the light duty potential ICE to EV fleet breaks down into:

- Sedans
- Sport Utility Vehicles (SUV)
- Pick-up Trucks
- Vans (cargo)

The distribution of vehicle types is important to note because EVs capable of replacing current ICE units varies significantly by vehicle class and brand, and most of the electrification challenges that occurs is related to or tied directly to functionality (like work-truck upfit compatibility, loaded cargo van range etc.) not a fundamental resistance to electrification in principle. As the electrification filter illustrates, (see above), a key piece of fleet electrification consideration is how a potential EV replacement will fit to support the work required to serve customers, not just related to meeting drive range needs

Sedans: Highest Electrification Viability

Sedans represent the clearest and probably most viable electrification opportunity in the purchase plan. In many instances, sedans only require a few modifications such as safety lighting if needed and do not require carrying heavy equipment. The current drive patterns for many sedans support the replacement of the current ICE unit with an electric unit. However, it is still critical to confirm the needs of the groups utilizing these units to confirm a good fit.

Key Factors Supporting Sedan Electrification

1. **Predictable Duty Cycles**
   Sedan assignments appear to involve:
   - Regional travel
   - Service Center-to-site-service center driving
   - Limited payload, upfit requirements
2. **Adequate EV Market Coverage**
   The EV sedan and compact crossover market already supports:
   - 250+ miles of real-world range
   - All-weather operation
   - Minimal payload impact on range
3. **Low Operational Risk**
   Unlike field trucks, sedans:
   - Rarely have to tow any equipment, trailers etc.
   - Usually do not require rear trunk or bed space or upfitting.
   - Are less likely to be loaded with heavy equipment.

Electrification Viability: HIGH

Sedans could be prioritized for near-term electrification (first-wave conversions). The spreadsheet already reflects alignment within fleet planning assumptions, and no systemic barriers are identified.

SUVs: Mixed but Often Viable

SUVs in the purchase plan sit between sedans and pick-ups in terms of viability.

Supportive Indicators

In the instance of SUVs, the market could support the viability of EVs in this category as range capabilities improve with each model year. The EV replacements planned for vehicles in the SUV category could match well with currently offered units (Equinox EV for example). There are two use cases that may work well for EV replacement but have varying viability on the SUV category. For most passenger carrying SUVs, the viability of an electrified unit could work well. For SUVs units that have a more work truck role, electrification may be more challenging due to payload, field inspection, and forestry roles putting them in situations that require more frequent charging. For these particular units, fleet needs to work closely with the business's use case and determine what EVs (if any) work best.

Electrification Viability: MODERATE

SUV electrification is viable where SUVs are used more as passenger support vehicles. Where SUVs are acting as substitutes for pick-ups, electrification becomes less viable.

Pick-ups: Constraints that Limit EV Adoption

Pick-ups are the Company's largest vehicle category and the largest electrification challenge. The viability of an EV pick-up truck relies heavily on its intended use. Where pick-up trucks require the Company standard spec 8-foot bed for some pick-trucks, an EV pick-up truck may

not work well as most EV pick-up trucks are built with shorter beds. In some cases, the Company is targeting smaller pick-up trucks where there is no EV option currently available.

Core Barriers to Pick-Up Electrification

Bed Size & Payload

Many Company pick-up trucks operate in field roles that require longer bed configurations for specialized racks and/or toolboxes. Current EV pick-ups offer shorter bed lengths and can lose significant range carrying or pulling heavy loads. When considering an EV pick-up truck, it is important to note these limitations to avoid compromising operations.

Duty Cycle & Uptime Requirements

Pick-up truck deployment often requires long field days that involve longer distances between charging or public charging. Pick-up trucks are also critical for storm or other emergency response readiness and must be able to operate in freezing weather, where up to 30% of range reduction can occur.

EV range degradation under:

- Cold temperatures – EV range drops as ambient temperatures drop.
- Heavy payloads – Cargo van carry the weight of shelving, supply materials and tools that can significantly reduce range.
- Longer trips at highway speeds – Driving long distances at 70 MPH in any EV significantly reduce overall range, especially on colder days when cabin temperatures require heating.

Idle-heavy work cycles – Some units have limited dwell time that may require more time to fully charge EV battery.

Market Gaps

While vehicles like the Silverado EV (battery only EV that is capable of 490-mile range) and the planned RAM EREV (equipped with a range-extender EV capable of over 600-mile range) are available, they are still noted as potential future solutions. For the purposes of this assessment, these two vehicles represent some of the best potential solutions because of their work truck specifications.

Electrification Viability: LOW (for many pick-ups)

Except for a small subset of lighter-duty pick-ups, most pick-up roles in this fleet should not be electrified with current technology without compromising mission capability.

Range-Extender EVs: An Opportunity

The technology to extend the range and field capability of an electrified pick-up truck is planned for 2026 and 2027 model years from two Michigan manufacturers, offering an opportunity to replace a light duty ICE pick-up truck with a plug-in pick-up with longer range, and shorter refueling times. An EV range extender is an auxiliary power unit, in this and most cases a small internal combustion engine, to supplement the range provided by the plug-in battery. The Company is closely monitoring planned offerings in this category including the vehicles below.

- RAM 1500 REV due late 2026
- Ford Lighting EREV planned for 2027, (both with plug in battery and range extender powertrains).

Why This Matters

Range-extender EVs address one of the single biggest EV hurdles: refueling timing and cargo weight limitations. While the Company has not had the opportunity to test a range extender equipped pick-up truck, the Company already has vehicles with this design in its fleet. The Chevrolet Volt is designed to use a battery for full EV driving for approximately thirty-five miles but is built with a small engine that charges the battery to continue driving after the electric only range has been depleted. This keeps the EV on the road for a longer period, shortening the refueling time until the unit can plug back in for the duration needed to fully recharge the battery. Pick-up trucks equipped with range extender EV powertrains represent an opportunity for the Company to add EV vehicles that lower fuel consumption without compromising storm response or weight related range reductions. These pick-trucks also offer a measure of range certainty, and less range anxiety under load, that full battery electric trucks struggle to provide. For pick-up truck opportunities where the size of the pick-up bed can acceptably be less than eight (8) feet, the coming offerings of range extender work truck equipped EV trucks from Michigan based manufacturers represent a promising opportunity.

Limits Still Apply

Even with EREVs:

- Bed size constraints remain – these must be replaced on a case-by-case basis through discussions with specific groups on how they are using their pick-up truck beds for supplies, upfits etc.
- Cost premiums may be high.

Electrification Viability: CONDITIONAL

Range-extender EVs represent a second-wave opportunity, but not a universal solution. The range extender power train strategy will be new to the market and while it is expected to increase pick-up truck viability in the EV space, real world use will determine whether these units will truly deliver on ICE to EV return on investment expectations, and manufacturer commitment to this approach going forward.

Cargo Vans: Electrification Fit Challenge to Date

No category is more challenging to electrify at this time than cargo vans. Cargo vans present a unique problem in that they require an upfit (usually consisting of metal shelving or drawers etc.) that carry equipment, tools, and other materials required to complete the work needed by crews. These vans must carry weight that is significant and must be considered when selecting a suitable EV replacement that would not add refueling (charging) time or other constraints to completing the work required. The potential need for midday charging requirements depending on how long an EV is deployed is also a key consideration. There may be limited opportunities to charge at public DC Fast Chargers.

The Company already has EV cargo van experience in the current fleet in use and has been used for relatively short distances as the Company learns more about their capabilities before purchasing more units.

The Company also had the opportunity to test a high roof EV cargo van. During the tests, the Company found that even under the no load conditions range the vehicle's use was not promising considering how much weight the van would have to hold once it was upfitted and loaded with tools and equipment supplies. There was feedback in regard to whether the van set up potentially would not work well with expectations from the workforce using them.

Core Constraints

1. **Upfit Weight** - Cargo vans are heavily modified with:
    - Shelving
    - Cabinets
    - Equipment

2. **Cold-Weather Penalty** - Vans are more impacted by:
    - Heavy upfits for shelving, tools and equipment loads.
    - HVAC load – many vans are deployed on the gas side of the business requiring workforce support.
    - Idling for cabin, equipment support
    - Stop-and-go driving.

Electrification Viability: VERY LOW

Based on direct operational experience, electrifying the Company's cargo vans should be avoided until:

- Battery energy density significantly improves, or
- Hybrid / REEV vans become commercially viable.
- Faster public charging solutions are available.

Conclusion

Vehicles Suited for Near-Term Electrification

- Sedans

- Passenger SUVs
- Light-duty pick-ups with minimal bed and payload needs (limited cases)

Vehicles Not Suited for Electrification Today

- Service vans (heavier loads – upfits, tools, supplies)
- Heavy-use pick-ups.
- Unit requiring:
    - Long beds
    - Heavy upfits.
    - Emergency readiness.

Transitional Technologies to Watch

- Range-extender electric pick-ups.
- Plug-in Hybrid pick-up trucks.
- Plug-in hybrid vans (if commercially viable).

Final Assessment

The Company's method towards fleet electrification is a mature, evidence-based approach. The limiting factors are not resistance or inertia—they are grounded in key items to consider including range, payload, learnings from current EVs and market availability. A selective electrification strategy, focused on sedans, appropriate pick-up trucks, and SUVs, while protecting mission-critical work vehicles, is operationally necessary.

Based on the Company's experience with both plug-in and fully battery electric vehicles, as well as workforce adaptation to the integration of electrified vehicles into daily operations, two primary attributes have emerged as critical filters in the fleet electrification replacement decision process: functional suitability and operational capability, particularly regarding range requirements. The Company has taken the opportunity to inspect, or test drive several EV

vehicles from start-up manufacturers, as well as established Michigan based manufacturers. There have been a couple instances where the manufacturer of the EV that the Company test drove failed and is no longer in business. There are other instances where established manufacturers have pulled back their EV offerings in response to current electrification acceptance. While both were not a good fit from a function perspective, it should be noted that there are also some reservations as to whether some EV vehicles and manufacturers will still be viable in the future (one of the vehicles the Company test drove from a well-established Michigan based manufacturer is no longer being produced just two years later). In both cases, the Company has been conservative in its approach, favoring a more measured, tactical, and pragmatic method to replacing ICE units with EVs. This is because the margin for error can significantly affect the work. It would not be to the Company's advantage to purchase vehicles from manufacturers that are not viable for the duration of a purchased unit's lifespan. Therefore, while the Company is still pursuing viable fleet electrification where possible, it must proceed in a manner that is seamless in its approach to the work fleet must support.

Category	Department Name Desc.	Vehicle Ty	Unit Age (months)	Replace Year	Replace VT	Potential Electrification Fit & Function Potential
PICKUP	FIELD OPERATIONS EAST CENTRAL ZONE 12	FL22	180	2025	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
VAN	EO-LVD-CENTRAL ZONE 2-SAGINAW-A	FL23	216	2028	FL23	No EVs in market that fit this application yet. - EXPRESS VAN
PICKUP (Silverac	GAS OPS-SOUTH-ZONE 1H	FL28	180	2026	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP (Sierra)	EO-SUBSTATION OPS G-BATTLE CRK & LANSING	FL28	132	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP (Sierra)	WM&CD-CEM-WBR/CLR/ALM	FL28	168	2026	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP (Sierra)	EO-LVD-NW ZONE 8-CADILLAC-A	FL28	168	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks. - Pulling up from 2028 due to major corrosion.
PICKUP (Sierra)	EO-LVD-NE ZONE 1-MIDLAND-A	FL28	168	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP (Sierra)	EO-LVD-SW ZONE 5-HASTINGS-A	FL28	168	2026	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
SEDAN	GAS OPS-SOUTHEAST C2	FL06	144	2028	FL07	Range examined may be good candidate depending for Equinox EV or similar
SEDAN	FIELD OPERATIONS SOUTHERN ZONE 22	FL06	144	2027	FL07	Range examined may be good candidate depending for Equinox EV or similar
SEDAN	EO-LVD-LAKESHORE ZONE 7-GREENVILLE-A	FL06	144	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
SUV	GAS OPS-SOUTH-ZONE 1H	FL07	144	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
SUV	GEP&S/GEP/MR&E TECH WEST	FL07	96	2028	FL07	Range examined - challenges with EV based on current driving patterns
SUV	EO-FORESTRY OPS-BAY CITY/MID	FL07	156	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
SUV	NDT MANAGEMENT	FL07	120	2027	FL07	Range examined may be good candidate depending for Equinox EV or similar
SUV	FIELD OPERATIONS NORTHEAST ZONE 5	FL07	156	2026	FL22	Range examined may be good candidate depending for Equinox EV or similar
SUV	GAS OPS - REG-SW	FL07	96	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	FIELD OPERATIONS NORTHEAST ZONE 6	FL22	180	2025	FL_28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GO-TO-PIPELINE & STORAGE-EAST	FL22	132	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	FIELD OPERATIONS SOUTHEAST ZONE 17	FL22	156	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.

PICKUP	CORPORATE SAFETY A	FL22	156	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	FIELD OPERATIONS SOUTHERN ZONE 22	FL22	156	2027	FL22	Range examined may be good candidate depending on bed size need. RAM REEV or Silverado EV could work
PICKUP	GO-GCON-MACOMB CONSTRUCTION F	FL22	144	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	NDT MANAGEMENT	FL22	132	2026	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	GEP&S/GEP/DIST ENGG W/DES-ENG	FL22	132	2028	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	CORPORATE FACILITIES ZONE 30	FL22	180	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GO-GCON-RESOURCE MGMT B I	FL22	144	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GAS OPS-NORTH-ZONE-3B	FL22	132	2028	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	WM&CD-CEM-GRN/FRE/BIG/GVL	FL22	168	2028	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	LVD DESIGN-LAN/OWS	FL22	192	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	CX&G-RO-REVENUE RECOVERY THEFT	FL22	132	2026	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	CX&G-RO-REVENUE RECOVERY THEFT	FL22	180	2026	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	LVD DESIGN	FL22	180	2025	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	GO-TO-M&R-NORTH	FL22	132	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	EO-LVD-SE ZONE 4-B CREEK-C	FL22	132	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	CX&G-RO-REVENUE RECOVERY THEFT	FL22	144	2027	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	CX&G-RO-REVENUE RECOVERY THEFT	FL22	144	2029	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	LVD DESIGN-WBR/CLR/ALM	FL22	180	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	LVD DESIGN-LAN/OWS	FL22	156	2027	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	CX&G-RO-REVENUE RECOVERY THEFT	FL22	144	2028	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	LVD SYSTEM PLANNING - WEST	FL22	180	2025	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.

PICKUP	REGULATORY STANDARDS & PROCEDURES	FL22	156	2027	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	NDT MANAGEMENT	FL22	144	2026	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	GAS OPS-CENTRAL-ZONE 1	FL22	132	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	CX&G-RO-REVENUE RECOVERY THEFT	FL22	144	2027	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	LVD DESIGN-JACK/ADR/SMN	FL22	168	2026	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	LVD DESIGN	FL22	168	2025	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	EO-FORESTRY OPERATIONS WEST	FL22	144	2024	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	PHYSICAL SECURITY & EMERGENCY MGT	FL22	132	2026	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	EO-LVD-NW ZONE 8-BENZIE	FL22	108	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	GO-GCON-RESOURCE MGMT B I	FL22	144	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	GAS OPS-NORTH-ZONE	FL22	156	2029	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	LVD PLANNING - NORTHEAST	FL22	180	2025	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	GO-GCON-FLINT CONSTRUCTION C	FL22	156	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market. - will not replaced with an EV
PICKUP	EPM- CONSTRUCTION MGMT- SUT	FL22	216	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
PICKUP	LVD SYSTEM PLANNING - WEST	FL22	180	2026	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
						Not a good candidate for current EV pick ups
PICKUP	GO-GCON-RESOURCE MGMT B I	FL22	156	2026	FL27A	
PICKUP	LVD PLANNING - NORTHEAST	FL22	180	2027	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	GO-GCON-MACOMB CONSTRUCTION A	FL22	156	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market. - will not replaced with an EV
PICKUP	LVD DESIGN-GRA/GRE	FL22	168	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.

PICKUP	GO-GAS O&M COMPRESSION I	FL22	156	2025	FL27	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	FIELD OPERATIONS SOUTHWEST ZONE 20	FL22	156	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GAS OPS SUPPLY & CONSTRUCTION	FL22	144	2029	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	GO-GAS C&S PLANNING &TECHNICAL SRVS	FL22	240	2027	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	FIELD OPERATIONS NORTHWEST ZONE 7	FL22	180	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	WM&CD-CEM-BCK/COLD/HAS/MAR	FL22	240	2026	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	CAMPBELL-FUEL HANDLING	FL22	180	2024	FL26	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	CX&G-RO-REVENUE RECOVERY THEFT	FL22	168	2026	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	FIELD OPERATIONS NORTHEAST ZONE 10	FL22	168	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	WM&CD-CEM-SAG/MID/BAY	FL22	240	2024	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	GEP&S/GEP/DIST ENGG W-DES	FL22	240	2027	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	CAMPBELL-FUEL HANDLING	FL22	228	2028	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	CX&G-RO-REVENUE RECOVERY THEFT	FL22	168	2028	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	WM&CD-CEM-SAG/MID/BAY	FL22	240	2027	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	WM&CD-CEM-LAN/OWO	FL22	216	2029	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	LVD DESIGN-SAG/BCY/MDL	FL22	240	2023	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	WM&CD-CEM-SAG/MID/BAY	FL22	216	2027	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	FIELD OPERATIONS SOUTHEAST ZONE 17	FL22	168	2024	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	EO-CFS WEST C	FL22	240	2024	FL22	Range examined may be good candidate for RAM REEV or similar with range extender powertrain.
PICKUP	LVD DESIGN-JACK/ADR/SMN	FL22	216	2026	FL10	Target is a Maverick size Pick Up - No EV option currently in market.
VAN	GAS OPS-EAST-ZONE	FL23	156	2026	FL28	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.

VAN	C&IS	FL23	120	2025	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2025	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	168	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST A4	FL23	144	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	108	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	144	2025	FL27	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	168	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	108	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2025	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-SOUTHEAST B3	FL23	132	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.

VAN	GAS OPS-NORTHEAST	FL23	156	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-SOUTHWEST A7	FL23	144	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	108	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	108	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2026	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2026	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.

VAN	GAS OPS SOUTHEAST A	FL23	132	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	144	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2029	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	144	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	108	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GO-GAS SYS ENHANCE-GAS O&M COR CON NE	FL23	156	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GO-GAS OPS-SOUTHWEST A1	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.

VAN	GAS OPS-SOUTHWEST A6	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	144	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-SOUTHEAST A7	FL23	204	2027	FL3	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS NORTHEAST A9	FL23	108	2025	FL27B	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	144	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	108	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	84	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	144	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2026	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST A	FL23	144	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.

VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	84	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NE	FL23	144	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST A2	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS NORTHEAST A9	FL23	144	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GO-GAS SYS ENHANCE-GAS O&M COR CON NE	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	108	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	84	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST B	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	132	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GO-GAS SYS ENHANCE-GAS O&M COR CON SW	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	132	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.

VAN	GAS OPS SOUTHWEST	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	144	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS -SOUTH-ZONE 2B	FL23	144	2025	FL28	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GO-GAS SYS ENHANCE-GAS O&M COR CON NE	FL23	144	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHWEST	FL23	84	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-SOUTHWEST A6	FL23	144	2025	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-SOUTHWEST A8	FL23	156	2029	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	FIELD OPERATIONS EAST CENTRAL ZONE 9	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-SOUTHEAST C2	FL23	144	2025	FL27	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	156	2027	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	108	2028	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS SOUTHEAST A	FL23	144	2029	FL23	Range concerns for similar EV vans in market once with upfit weight plus tools significantly reduces advertised range.
VAN	GAS OPS-NORTHEAST	FL23	144	2025	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.
VAN	FIELD OPERATIONS SOUTHEAST ZONE 19	FL23	144	2029	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.
VAN	GO-GAS SYS ENHANCE-GAS O&M COR CON SW	FL23	120	2029	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.

VAN	GO-TO-PIPELINE & STORAGE-NORTH-SAGINAW	FL23	192	2023	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.
VAN	GEP&S/GEP/MR&E TECH WEST	FL23	192	2027	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.
VAN	GEP&S/GEP/MR&E TECH WEST	FL23	192	2027	FL23	Range concerns for similar EV cans in market once. Upfit weight plus tools significantly reduces advertised range.
PICKUP	EO-LVD-EAST ZONE 3-LANSING-A	FL28	132	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	FIELD OPS ENVIRONMENTAL COMPLIANCE	FL28	168	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	CX&T-IT-IP&S-WIRELESS CONNECTIVITY	FL28	168	2028	FL23	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-LVD-EAST ZONE 3-FLINT	FL28	132	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-LVD-NW ZONE 8-TRAVERSE-B	FL28	252	2024	FL26	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-SUBSTATION OPS F-MUSKEGON	FL28	120	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GO-TO-PIPELINE & STORAGE-NORTH-WELL SER	FL28	180	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GAS OPS -SOUTH-ZONE 2B	FL28	180	2029	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	CAMPBELL-FUEL HANDLING	FL28	192	2024	FL26	Replacing with a class 3 truck - not a good EV candidate
PICKUP	FIELD OPERATIONS NORTHWEST ZONE 4	FL28	216	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	FIELD OPERATIONS NORTHEAST ZONE 10	FL28	216	2029	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	LVD DESIGN-HAM/HST	FL28	156	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	RENEWABLES GEN- SOLAR & BATTERY	FL28	132	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	FIELD OPERATIONS NORTHWEST ZONE 7	FL28	216	2029	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	LAND SERVICES SURVEY	FL28	180	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-LVD-EAST ZONE 3-LANSING-A	FL28	156	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	RIVER HYDRO OPERS	FL28	132	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GAS OPS SOUTHEAST A	FL28	132	2029	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.

PICKUP	LAND SERVICES SURVEY	FL28	156	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GAS OPS-CENTRAL-ZONE 1	FL28	156	2026	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-SUBSTATION OPS K-GRAND RAPIDS	FL28	180	2026	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-SUBSTATION OPS C-MIDLAND	FL28	156	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	FIELD OPERATIONS SOUTHWEST ZONE 14	FL28	216	2027	FL45	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-SUBSTATION OPS K-GRAND RAPIDS	FL28	180	2026	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	FIELD OPERATIONS SOUTHWEST ZONE 20	FL28	216	2029	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	CAMPBELL-FUEL HANDLING	FL28	156	2025	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GAS OPS -SOUTH-ZONE 2B	FL28	156	2029	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-LVD-NW ZONE 8-BOYNE-A	FL28	132	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GO-TRANS OPS EAST	FL28	156	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GO-TO-PIPELINE & STORAGE-WEST	FL28	180	2029	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-LVD-SE ZONE 4-ADRIAN-B	FL28	156	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	RIVER HYDRO OPERS	FL28	192	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-LVD-LAKESHORE ZONE 7-LUDINGTON	FL28	156	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	LVD EAST ZONE 3	FL28	156	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	FIELD OPERATIONS SOUTHEAST ZONE 17	FL28	288	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-SUBSTATION OPS G-BATTLE CRK & LANSING	FL28	180	2026	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	CHEMISTRY SERVICES ANALYSTS	FL28	132	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-LVD-NE ZONE 1-MIDLAND-A	FL28	180	2026	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	GAS OPS-SOUTHEAST A1	FL28	144	2028	FL28	EV Pick Up beds are too small to replace most of these pick up trucks. Target larger heavy duty pick up.

PICKUP	NDT MANAGEMENT	FL28	132	2029	FL28	EV Pick Up beds are too small to replace most of these pick up trucks. Target larger heavy duty pick up.
PICKUP (Sierra)	EO-LVD-SE ZONE 4-ADRIAN-B	FL28	132	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP (Sierra)	EO-SUBSTATION OPS C-MIDLAND	FL28	132	2026	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP (Silverac	FIELD OPERATIONS NORTHWEST ZONE 7	FL28	180	2028	FL45	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP (Sierra)	CX&T-IT-IP&S-MONITORING	FL28	180	2027	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-SUBSTATION OPS K-GRAND RAPIDS	FL28	12	2023	FL28	EV Pick Up beds are too small to replace most of these pick up trucks.
PICKUP	EO-SUBSTATION OPS I-TRAVERSE CITY	FL28	168	2024	FL28	We tried out transit an EV van in Livonia, range was a big concern especially when loaded with equipment and tools.
PICKUP (Sierra)	EO-SUBSTATION OPS D-FLINT	FL28	168	2027	FL28	We tried out transit an EV van in Livonia, range was a big concern especially when loaded with equipment and tools.
PICKUP	EO-SUBSTATION OPS G-BATTLE CRK & LANSING	FL28	168	2024	FL28	We tried out transit an EV van in Livonia, range was a big concern especially when loaded with equipment and tools.
PICKUP	GAS OPS-NORTH-ZONE-3A	FL28	168	2025	FL28	We tried out transit an EV van in Livonia, range was a big concern especially when loaded with equipment and tools.

Fleet order requirement:

"Include more details regarding existing vehicle usage by vehicle specification."

Fleet Standard 06:

Fleet Standard Use: The Consumers Energy Fleet Standard 06 is a 4-door sedan used for general personnel transportation. The Standard 06 may or may not be a company marked vehicle.

Company Use: Common

Fleet Standard 07:

Fleet Standard Use: The Consumers Energy Fleet Standard 07 is a 4-door compact SUV used for general personnel transportation. The Standard 07 may or may not be a company marked vehicle.

Company Use: Common

Fleet Standard 22:

Fleet Standard Use: The Consumers Energy Fleet Standard 22 is a company marked ½ ton pickup. This vehicle is for general use and personnel transportation.

Company Use: Common

Fleet Standard 23:

Fleet Standard Use: The vehicle is a one ton Cargo van intended to transport Service personnel who provide a multitude of service. The van carries a crew of one or two people and travels paved roads at highway speeds. In some situations, this vehicle is operated at night. In special applications the vehicle will tow.

Company Use: Common

Fleet Standard 24:

Fleet Standard Use: The Fleet Specification 24 Cathodic van is a ½ ton (120.6" wheelbase) cargo van. It will be used to transport tools and equipment utilized by our Cathodic Operations employees. This unit will be upfit with Sortimo storage products and shelving units.

Company Use: Common

Fleet Standard 25:

Fleet Standard Use: The vehicle is a half-ton all-wheel-drive 135" wheelbase cargo van intended to transport service personnel who provide a multitude of service. The van carries a crew of one or two people and travels paved roads at highway speeds. In some situations, this vehicle is operated at night.

Company Use: Common

Fleet Standard 26:

Fleet Standard Use: The fleet specification 26 is intended to transport Electric Substation personnel. The truck normally carries a crew of one or two people. The vehicle shall be expected to tow trailers not exceeding 7,000lb gross trailer weight and a maximum tongue weight of 1,000lb.

Company Use: Electric

Fleet Standard 27A:

Fleet Standard Use: The fleet specification 27 is intended to transport Gas T&S personnel for performing measurement regulation and pipeline storage work methods. The truck normally carries a crew of one or two people. In some situations, this vehicle is operated at night. The vehicle shall be expected to tow trailers not exceeding 7,000lb gross trailer weight and a maximum tongue weight of 1,000lb.

Company Use: Gas

Fleet Standard 27B:

Fleet Standard Use: The fleet specification 27B is intended to transport personnel and equipment to support the utility. The truck normally carries a crew of one or two people. In some situations, this vehicle is operated at night.

Company Use: Gas

Fleet Standard 28:

Fleet Standard Use: The Fleet Standard 28 is a ¾ ton 2wd or 4wd drive pickup that may have various uses. This vehicle configuration is spec'd for application in which it will be used.

Company Use: Common

Fleet Standard 36:

Fleet Standard Use: The fleet specification 36 is intended to transport electric meter personnel who set and remove electric meters. The truck normally carries a crew of one or two people. In some situations, this vehicle is operated at night.

Company Use: Electric

Fleet Standard 37:

Fleet Standard Use: This vehicle consists of a light-duty 84" CA gasoline dual rear wheel four-wheel drive extended cab chassis with 186" wheelbase. Installed on the cab chassis is a custom service body 94" wide and 133" long. The Fleet specification 37 gas construction service truck is intended to support gas construction personnel who maintain gas distribution and transmission pipeline. The truck normally carries a crew of one or two people and travels paved or gravel roads. In some situations, this vehicle is operated at night and off road. This vehicle shall be expected to tow trailers with a maximum gross weight of 14,000lb and have a maximum tongue weight of 2,800lb.

Company Use: Gas

Fleet Standard 39:

Fleet Standard Use: The vehicle is a high roof extended-length cargo van with a 148" WB. The Fleet Specification 39 Thumper van is used primarily for electric underground fault detection. This unit includes a van interior package and an arc reflection system.

Company Use: Common

Fleet Standard 41:

Fleet Standard Use: This vehicle consists of a light-duty 60" CA gasoline dual rear wheel four-wheel drive extended cab chassis. Installed on the cab chassis is a custom service body 94" wide and 118" long including a 16" tail shelf. The standard includes supplier provided welding equipment and deck mounted crane. The Fleet specification 41 light duty welding truck is intended to transport Gas Distribution and Gas T&S personnel who weld and maintain gas distribution and transmission pipelines. The truck normally carries a crew of one or two people and travels paved or gravel roads. In some situations, this vehicle is operated at night and off road. This vehicle shall be expected to tow trailers with a maximum gross weight of 14,000lb and have a maximum tongue weight of 2,800lb.

Company Use: Gas

Fleet Standard 42:

Fleet Standard Use: The fleet specification 42 is intended to transport personnel and materials to support the utility. It has an enclosed service body that allows for personnel to assemble materials in a controlled environment and then install them on the jobsite. The truck normally carries a crew of one or two people. In some situations, this vehicle is operated at night. The vehicle shall be expected to tow trailers not exceeding 14,000lb gross trailer weight and a maximum tongue weight of 1,400lb.

Company Use: Common

Fleet Standard 43:

Fleet Standard Use: This vehicle is a light-duty, 16,500 lb. GVWR regular cab, four-wheel drive, 60" CA, gasoline dual rear-wheel chassis up-fit with a Consumers Energy specification two-to-three-yard dump body and Consumers Energy Fleet accessories. Its intended use is to haul debris from excavation sites and transport gas construction personnel and materials. The truck may also pull a plastic reel trailer, small trencher, directional boring machine, flashing arrow board, or compressor. The expected towing capacity when the dump is empty is 14,000lb gross trailer weight and 2,800lb tongue weight.

Company Use: Common

Fleet Standard 44:

Fleet Standard Use: This Vehicle is used primarily for construction and maintenance of the Company's underground gas distribution systems. A crew of two is assigned to the truck. The truck is required to carry material cargo supplies and tools weighing approximately 7,000 pounds for installation of gas distribution facilities. The truck normally pulls a trailer loaded with trenching equipment with a combined weight of 30,000 lbs. The truck is expected to travel at highway speeds and be capable of off-road travel as well. The truck will be equipped with lighting for nighttime site work and enhanced lighting for roadway safety. The truck will be designed and built with ergonomic features focused on safe operations for the crew.

Company Use: Gas

Fleet Standard 45:

Fleet Standard Use: The fleet specification 45 is intended to support garage service repair calls. The truck normally carries a crew of one or two people. In some situations, this vehicle is operated at night. The vehicle shall be expected to tow trailers not exceeding 7,000lb gross trailer weight and a maximum tongue weight of 1,000lb.

Company Use: Common

Fleet Standard 54:

Fleet Standard Use: This specification is for a 4x2 regular cab chassis with dual rear wheels. The chassis has a GVWR of 33,000 lbs. and a GCWR of 80,000 lbs. The cab to axle is 84", wheelbase 150", and axle to frame of 63". The truck will be used primarily for transporting materials in its 5-yard struck hydraulic dump body. The vehicle shall be capable of towing equipment trailers weighing up to 30,000 lbs. provided are street side and curbside under body toolboxes. An electric tarping system with a tarp tensioner is provided. Also provided are Oak side boards. The truck normally carries a crew of one to two people and travels on paved or gravel highways.

Company Use: Common

Fleet Standard 55:

Fleet Standard Use: This specification is for a 6x4 regular cab chassis with tandem dual rear wheels. The chassis has a GVWR of 54,000 lbs. and a GCWR of 80,000 lbs. The cab to axle is 123", wheelbase 189", and axle to frame of 75". The truck will be used primarily for transporting materials in its 10-yard struck hydraulic dump body. The vehicle shall be capable of towing equipment trailers weighing up to 30,000 lbs. provided are street side and curbside under body toolboxes. An electric tarping system with a tarp tensioner is provided. Also provided are Oak side boards. The truck normally carries a crew of one to two people and travels on paved or gravel highways.

Company Use: Common

Fleet Standard 57:

Fleet Standard Use: This vehicle is utilized as an Electric and Gas Operations derrick crane truck. The derrick chassis has either a 6x4 or 6x6 chassis. The truck is utilized for construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off-road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.

Company Use: Common

Fleet Standard 59:

Fleet Standard Use: The Fleet Standard 59 is a miscellaneous specification for unique vehicles needed to conduct Gas Operations.

Company Use: Gas

Fleet Standard 60:

Fleet Standard Use: The fleet specification 60 is intended to transport electric substation personnel for performing substation maintenance work methods to support the utility. The truck normally carries a crew of one or two people. In some situations, this vehicle is operated at night. The vehicle shall be expected to tow trailers not exceeding 14,000lb gross trailer weight and a maximum tongue weight of 1,400lb.

Company Use: Electric

Fleet Standard 64:

Fleet Standard Use: This vehicle is an Electric Operations 41-foot aerial beam truck, dual rear wheel with a 120-inch-long steel service body. The truck will have a 3,000-pound payload capacity. This is utilized with one operator performing service and troubleshooting activities on the electric service infrastructure. The unit is utilized on and off paved roads in addition to off road conditions to access the electric infrastructure. This vehicle is designed to provide versatile platforms and used during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 65:

Fleet Standard Use: This vehicle is an Electric Operations 38-foot aerial beam truck, dual rear wheel with a 120-inch-long steel service body. The unit is utilized with one operator performing service and troubleshooting maintenance and repair of streetlights on the electric service infrastructure. The unit is utilized on and off paved roads, to access the electric infrastructure. The vehicle is designed to provide a versatile safe platform and used during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 66:

Fleet Standard Use: This specification is intended to be used primarily for maintenance of the underground electric utility system infrastructure. The step van primarily travels paved roads and supports a crew of two people. A maximum payload of 10,000lbs (tools, materials, accessories, fuel, trailer, and occupants) is expected to be transported by the vehicle. In some situations, this vehicle is operated at night. The step van is equipped with many accessories that support the utility's work methods. The step van shall be expected to tow trailers not exceeding 7,000lb gross trailer weight and a maximum tongue weight of 1,000lb.

Company Use: Electric

Fleet Standard 67:

Fleet Standard Use: The Electric Substations Truck is 25,500 lb. GVWR, diesel powered, dual rear wheel cab-chassis outfitted with a 111" long service body. The unit has a minimum payload capacity of 5,000 lbs. and towing capacity of not more than 15,000 lbs. The owner supplied chassis has a 64.45 cab to axle dimension, vertical exhaust, air brakes and 245/70R19.5 tires. The truck normally carries a crew of one to three people and travels on paved or gravel highways and snow-covered substation driveways. This vehicle is designed to provide a versatile platform for installing and maintaining electric substations.

Company Use: Electric

Fleet Standard 68:

Fleet Standard Use: The chassis is a 158" wheelbase, 14,500 GVWR, and a V-10 gasoline engine. Stripped chassis specifications are stated in section 4.0 specifications chassis. The body is a 14-foot cargo length walk-in van up fit and commissioned to Consumers Energy specifications. The Fleet Standard 68 14-foot GAS Service walk-in vans are intended to transport personnel and materials and provide an enclosed work environment. This vehicle is required to tow up to a 7,000-pound GVWR trailer with electric brakes. The vehicle will travel 10,000 to 15,000 miles per year and has a life expectancy of 20 years. The Fleet Standard 68 14-foot GAS Service walk-in van carries a crew of one or two people and travels on paved roads. In some situations, this vehicle is operated at night.

Company Use: Gas

Fleet Standard 75:

Fleet Standard Use: This vehicle is an Electric Operations Digger Derrick truck with single rear wheel four when drive chassis. The truck is utilized for electric overhead construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing purposes of various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 77:

Fleet Standard Use: This vehicle is an Electric Operations Digger Derrick truck. The digger derrick chassis is either a 6x4 or 6x6 chassis. The truck is utilized for electric overhead construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 82:

Fleet Standard Use: This vehicle is an Electric Operations Aerial Device truck with single rear axle four-wheel drive chassis. The truck is utilized for electric overhead construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing purposes of various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.
Company Use: Electric

Fleet Standard 83:

Fleet Standard Use: This specification is a single axle dual rear wheel 4x2 cab-chassis with a minimum GVWR of 33,000 lbs. and a minimum GCWR of 60,000 lbs. and a CA of 120". The cab chassis is up fitted with a 16’ flatbed body with stake racks and lift gate. The truck is a specialized piece of equipment used to transport and deliver materials. The truck normally carries a crew of one or two people. In some situations, this vehicle is operated at night.

Company Use: Common

Fleet Standard 85:

Fleet Standard Use: The chassis is a tandem axle general freight regional haul 6X4 day cab tractor with fifth wheel hitch.

Company Use: Common

Fleet Standard 86:

Fleet Standard Use: This chassis is designed to have various platform bodies 16, 20, and 24 feet long.

Company Use: Common

Fleet Standard 89SM:

Fleet Standard Use: This vehicle is an Electric Operations Aerial Device truck with either a 6x4 or a 6x6 chassis. The truck is utilized for electric overhead construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing purposes of various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 89TM:

Fleet Standard Use: This vehicle is an Electric Operations Aerial Device truck that has either a 6x4 or a 6X6 chassis. The truck is utilized for electric overhead construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing purposes of various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 90A:

Fleet Standard Use: This specification is for a 4x2 dual rear wheel flat-bed chassis. The chassis has a GVWR of 33,000 lbs. and a GCWR of 80,000 lbs. The cab to axle is approximately 120”, wheelbase 187”, and axle to frame of 75”. The flatbed body has incorporated into its storage bin packs both street side and curbside and a deck mounted storage box. Provisions are provided to carry either three or four reels of wire that would pay out either over both sides of the trucks or out the rear. The truck is expected to carry up to 12,000lb of payload and capable of towing a tag trailer up to 30,000lb GVWR.

Company Use: Electric

Fleet Standard 90B:

Fleet Standard Use: The chassis has a GVWR of 33,000lbs. The GCWR is 80,000lbs. The cab to axle is 120” with the wheelbase approximately 187”. The AF is 75”. The chassis will have a flatbed body with behind the cab bin packs installed by an up-fitter. Also installed by an up-fitter is a PTO driven under deck air compressor. The truck is expected to tow up to a 30,000lb GVWR tag equipment trailer.

Company Use: Gas

Fleet Standard 94SM:

Fleet Standard Use: This vehicle is an Electric Operations Aerial Device truck that has either a 6x4 or a 6x6 chassis. The truck is utilized for electric overhead construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing purposes of various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 94TM:

Fleet Standard Use: This vehicle is an Electric Operations Aerial Device truck that has either a 6x4 or a 6X6 chassis. The truck is utilized for electric overhead construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing purposes of various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 96S:

Fleet Standard Use: This vehicle is an Electric Operations Aerial Device truck with either a 6x4 or a 6x6 chassis. The truck is utilized for electric overhead construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing purposes of various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 96T:

Fleet Standard Use: This vehicle is an Electric Operations Aerial Device truck with dual rear wheel has either a 6x4 or a 6X6 chassis. The truck is utilized for electric overhead construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing purposes of various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 97T:

Fleet Standard Use: This vehicle is an Electric Operations Aerial Device truck that has either a 6x4 or a 6X6 chassis. The truck is utilized for electric overhead construction and maintenance of the Consumers Energy infrastructure. The unit is operated with a crew at a work site. The vehicle is utilized on and off paved roads, in addition to off road conditions necessary to access the electric infrastructure. The vehicle is utilized for towing purposes of various utility application trailers including construction equipment and pole trailers. The vehicle is utilized during daytime and nighttime operations.

Company Use: Electric

Fleet Standard 98:

Fleet Standard Use: This specification consists of a chassis that will support a behind the cab mounted 23 ton rated 100-foot crane with a three to four section boom. Provided is a 21-foot-long steel flatbed behind the crane. Cargo caring capacity on the flat bed shall be rated for up to 12,000 pounds while the spec 98 is towing up to a 30,000-pound GVWR trailer. The chassis shall be capable of supporting the crane, flatbed body, up to 12,000 pounds of cargo on its flatbed, and tow a 30,000-pound GVWR trailer with an estimated 6,000-pound tongue weight and not exceed the state of Michigan maximum weight and axle load limits not using the bridge formula. Weights shall also not exceed tire manufacturer maximum loading each.

Company Use: Common

Fleet Standard 99:

Fleet Standard Use: The Fleet Standard 99 is a miscellaneous specification for unique equipment needed to conduct Electric Operations.

Company Use: Electric

Fleet Standard E10:

Fleet Standard Use: The Consumers Energy specification E10 is used primarily for utility construction throughout the state. This unit will be operated in diverse types of soil and conditions by our electric and gas crews. It will be utilized for the burial of service cable and gas line.

Company Use: Common

Fleet Standard E11:

Fleet Standard Use: The Consumers Energy Specification E11 - Medium Duty Trencher is used primarily for the installation of underground electric and gas infrastructure in diverse types of soil and conditions throughout the state. Standard Equipment consists of a backhoe, and a 48-inch trenching boom. Options would include a combination vibratory plow/trencher as well as rubber tracks.

Company Use: Common

Fleet Standard E12:

Fleet Standard Use: The use for this unit will be specified at the point of requirement.

Company Use: Common

Fleet Standard E20:

Fleet Standard Use: The Consumers Energy Fleet specification E20 is primarily used as a multi-purpose utility machine. Its many functions may include truck loading and trenching. The fleet specification E20 can also be used as a tool carrier. Front or rear couplers may be requested. Attachments such as front forks, rear hoe-packs and hammers may be utilized. The Fleet specification E20 will be operated on and off pavement and at times encounter soft underfoot soil conditions.

Company Use: Common

Fleet Standard E22:

Fleet Standard Use: The use for this unit will be specified at the point of requirement.

Company Use: Common

Fleet Standard E25:

Fleet Standard Use: This specification is a compact mini track loader with select attachments, securement devises, and transport trailer. The Consumers Energy Fleet specification E25 is primarily used as a multi-purpose compact rubber track loader with the abilities to operate many hydraulic work tools that support the utility.

Company Use: Common

Fleet Standard E26:

Fleet Standard Use: This specification is a skid steer loader provided with select attachments. The E26 is primarily used as a multi-purpose skid steer loader with pneumatic rubber tires or rubber tracks that will operate an assortment of standard flow hydraulic and non-hydraulic work tools that support the utility. This specification includes a transport trailer with machine securement included.

Company Use: Common

Fleet Standard E30:

Fleet Standard Use: This specification is a track dozer provided with select options. The E30 is primarily used as a multi-purpose small track type dozer for light stripping, grading, and cleanup utility work in soft underfoot conditions.

Company Use: Common

Fleet Standard E36:

Fleet Standard Use: This specification is a compact excavator provided with select attachments and transport trailer. The E36 is primarily used as a multi-purpose compact digging and trenching utility machine. Exact size is determined at point of order.

Company Use: Common

Fleet Standard E53:

Fleet Standard Use: This specification is for a standalone welder / generator. The use for this unit will be specified at the point of requirement.

Company Use: Gas

Fleet Standard E60:

Fleet Standard Use: The Consumers Energy specification E60 is used for material handling and field operations. This specification is a Forklift with selectable capacity and lift heights depending on business needs.

Company Use: Common

Fleet Standard E67:

Fleet Standard Use: The use of this Mobile Crane will be specified at the point of requirement.

Company Use: Gas

Fleet Standard E72:

Fleet Standard Use: The use for this Switcher Locomotive will be specified at the point of requirement.

Company Use: Generation

Fleet Standard E73:

Fleet Standard Use: This specification is a hydraulic excavator with a minimum operating weight of 47,000 lbs. and 153 horsepower. The maximum width over the track shoes shall be 10' 6". This machine has steel, 800mm triple grouser track shoes; an auxiliary hydraulic circuit with hydraulic lines ran to the end of the stick to operate optional hydraulic hammers, compactors, or hydraulic thumb. The machine is equipped with the manufacture's long undercarriage, standard boom length, and an approximate stick length of 9' 6".

Company Use: Gas

Fleet Standard E74:

Fleet Standard Use: The use for this Wheel Dozer will be specified at the point of requirement.

Company Use: Generation

Fleet Standard E75:

Fleet Standard Use: The use for this Tracked Dozer will be specified at the point of requirement.

Company Use: Generation

Fleet Standard E76:

Fleet Standard Use: The use for this Articulated Haul Truck will be specified at the point of requirement.

Company Use: Generation

Fleet Standard E78:

Fleet Standard Use: The use for this Off-Road Water Truck will be specified at the point of requirement.

Company Use: Generation

Fleet Standard E79:

Fleet Standard Use: The Consumers Energy specification E79 directional boring machine is used primarily for the installation of underground infrastructure for Consumers Energy. Manufacture standard features on the drill will be utilized. This Directional Drill and trailer combination is available in 3 different sizes, to be determined at point of order.

Company Use: Common

Fleet Standard E80:

Fleet Standard Use: This standard provides the specifications for a track carrier to mount a digger derrick pin on a bucket to be used in adverse weather or adverse ground conditions. This unit shall comply with all ANSI and federal regulations that apply to this vehicle.

Company Use: Electric

Fleet Standard E81:

Fleet Standard Use: The Consumers Energy specification E81 backyard pole setter and transport trailer is used primarily for construction and maintenance of the electric overhead utility infrastructure. The principle operating environments this unit are confined, restrictive, and limited accessible areas that require the equipment as specified within this scope.

Company Use: Electric

Fleet Standard E90:

Fleet Standard Use: The Consumers Energy specification E90 Diesel All Terrain Utility Vehicle is used primarily for supporting the utility by transporting people, material, and supplies.

Company Use: Common

Fleet Standard E95:

Fleet Standard Use: This Aerial Platform Lift equipment is used primarily for maintenance, repairs, and service in and around our electric substations.

Company Use: Common

Fleet Standard E99:

Fleet Standard Use: The Fleet Standard E99 is an equipment standard for miscellaneous equipment used.

Company Use: Common

Glossary

Fleet Standard: the specific configuration of a unit to meet the needs of its original intended purpose.

Fleet Standard Use: a description and usage of a vehicle to help determine the best fit in the workforce.

Company Use: the principal business function of the company the vehicle is utilized. (Gas, Electric, Generation, and Common)

Gas: vehicles used only for the gas business functions.

Electric: vehicles used only for the electric business functions.

Generation: vehicles used only for the generation business functions.

Common: vehicles that may be used for all business functions such as gas, electric, and generation.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

JON J. KOETJE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Karn Units 1 & 2 Decommissioning Plan Expenditures

Case No.: U-22070
Exhibit No.: A-152 (JJK-1)
Page: 1 of 1
Witness: JJKoetje
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)
	Period	**2022-2026**		**2025**		
Line No.	**Activity**	**Projected (2023)**	**Actual and Projected (2026)**	**Projected**	**Actual**	**Variance**
1	Utility Separation	2,453,260	-	165,408	-	165,408
2	Decommissioning	7,628,332	9,733,355	-	-	-
3	Abatement	14,750,163	7,142,460	-	1,308,633	(1,308,633)
4	Demolition	26,826,467	22,876,755	8,258,785	11,223,047	(2,964,262)
5	Asset Recovery	(17,895,829)	(9,917,039)	-	(6,193,456)	6,193,456
6	Environmental	9,645,887	6,767,815	-	753,864	(753,864)
7	Restoration	4,502,339	13,144,140	-	8,661,918	(8,661,918)
8	Inventory Write Off	6,971,387	3,663,641	-	-	-
9	Contingency	17,042,850	375,000	703,749	-	703,749
10	Project Indirects	25,129,349	26,705,546	2,682,058	663,886	2,018,172
11	Interim COR	-	-	-		-
12	**Total**	97,054,205	80,491,673	11,810,000	16,417,892	(4,607,892)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
JHC Decommissioning Plan Expenditures

Case No.: U-22070
Exhibit No.: A-153 (JJK-2)
Page: 1 of 1
Witness: JJKoetje
Date: June 2026

	(a)	(b)	(c)
Line No.	**Activity**	**Total Project Actual and Projected**	**2025 Actual**
1	Utility Separation	1,002,583	114,004
2	Decommissioning	51,222,820	1,115,379
3	Abatement	-	-
4	Demolition	174,896,148	2,000,400
5	Asset Recovery	-	-
6	Environmental	2,715,549	38,860
7	Restoration	2,659,908	-
8	Inventory Write Off	22,687,901	5,531
9	Contingency	44,697,968	-
10	Project Indirects	80,117,124	1,228,917
11	Interim COR	-	-
12	**Total**	380,000,001	4,503,092

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

KURT K. LAFRANCE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

CONSUMERS ENERGY
ELECTRIC ASSET MANAGEMENT

High Voltage Distribution(HVD) Pole Inspection Specifications

1. GENERAL SPECIFICATIONS

1.1. Consumers Energy shall provide all maps necessary for the wood pole inspection work to be performed.

1.2. The Contractor shall furnish all tools, equipment, inspection tags, bore tags, red tags and labor as required for the completion of wood pole inspection as prescribed in these specifications.

1.2.1. Each foreman employed by the Contractor working for Consumers Energy shall be a permanent, full-time employee of the Contractor. Each foreman shall have adequate training and not less than eight weeks experience as a Pole Inspection Foreman.

1.2.2. Each supervisor employed by the Contractor working for Consumers Energy shall be a permanent, full-time employee of the Contractor having not less than two years experience in supervising pole inspection crews.

1.2.3. The Contractor shall supply to a Consumers Energy representative written verification of the training and experience of each foreman and supervisor working for Consumers Energy before such work begins.

1.3. The Contractor shall inspect all poles with Consumers Energy facilities on them, which are connected electrically to the circuit or line section specified. All stub poles that are used for guying purposes should also be inspected. Poles within the protective fence of an electric substation shall also be inspected. Vacated or cut-off poles that had/have 3rd party attachments located adjacent to a Consumers Energy pole shall not be inspected, but the adjacent pole inspection record shall include yes or vacant value in the *PULL POLE* field.

1.3.1. For safety purposes, at least one individual per pole inspection team must attend substation entry training provided by Consumers Energy prior to entering a substation peremeter fence.

1.4. A representative of the Contractor shall be involved in a periodic conference call/meeting with Consumers Energy representatives to discuss inspection status and issues that may arise.

1.5. The Contractor shall electronically report the following information to Consumers Energy's representative each Monday by 12:00 noon (the format will be agreed upon with the Consumers Energy representative in advance):

1.5.1 Number of people who worked the previous week.

1.5.2 Specific days of week that each person worked during the previous week.

1.5.3 Specific circuit or line section that each crew worked during the previous week.

1.5.4 Planned circuit or line section of each crew for the current week.

1.6. The Contractor shall obtain, at their expense, all necessary permits required to complete the work prior to beginning the work requiring such permits.

1.7. Monthly the Contractor shall submit electronically via E-mail to a designated Consumers Energy's representative an invoice for the entire circuits or line sections that were completed. The Contractor shall include with each invoice a statement summarizing all work performed in each category of billing units.

1.8. The Contractor shall submit pole inspection data per individual circuit or line section, with the following conditions:

1.8.1. The data will be in Microsoft excel and either Microsoft Access format (MDB file) or ESRI Shapefile format.

1.8.2. CE Attachment B – Data Format lists the required data to capture for each pole inspection with a specific schema for Microsoft excel and either Microsoft Access format or ESRI Shapefile format.

1.8.3. A template for Microsoft excel and either Microsoft Access MDB file or ESRI Shapefile format with the required specific schema will be provided.

1.8.4. Transfer of circuit or line section data, including photos, Microsoft excel file and Microsoft Access database file or ESRI Shapefile will be packaged as one zip file named with the name and number of the Line Section or Feeder ID. The zip file will be transferred using FTP (File Transfer Protocol).

1.8.5. A sample set of twenty-five (25) pole data records fulfilling all data requirements specified in CE Attachment B – Data Format are to be submitted two weeks before start of pole inspections for testing and validation purposes.

1.9. The Contractor will specify and follow their quality assurance and audit process. The Contractor will work with Consumers Energy on an agreed upon acceptance process to ensure inspection and data quality requirements are achieved.

1.10. All work, including obtaining, recording, and reporting of the inspection data shall be entirely satisfactory to Consumers Energy and shall be subject to inspection by and approval of Consumers Energy. Any work submitted needing correction may be rejected and/or may delay payment. Common data errors need to be identified and corrected before data is submitted.

1.11. Consumers Energy may request a sample data set of an incomplete inspected circuit or line section for auditing purposes.

1.12. Contractor shall return any items/materials received from Consumers Energy and not used for inspection purposes.

2. VISUAL INSPECTION & GPS LOCATION SPECIFICATIONS

2.1. The Contractor will perform a visual pole inspection of the applicable poles on each circuit or line section assigned and record data per 1.8 above.

2.2. The Contractor shall report any system threatening or safety concerns promptly to the designated Consumers Energy representative(s). This includes but is not limited to:

1) A pole that the contractor determines to be an immediate replacement.
2) Any hazard that the contractor determines is a threat to public safety.
3) A floating phase or neutral wire.
4) A broken or severely cracked crossarm.

2.2.1 The Contractor could be requested by a Consumers Energy representative to stay on site until relieved by Consumers Energy representative. Consumers Energy will reimburse Contractor for time spent on site at agreed upon time and material rate.

2.2.2 A follow up E-mail shall be sent to a designated Consumers Energy representative for said pole or hazard within 3 days of call-in. A report template will be provided.

2.3. The Contractor will install a Consumers Energy pole number tag placed immediately above the inspection tag (if present), if a legible existing Consumers Energy pole number tag is not already present.

2.3.1. The Consumers Energy pole number tag is a numbered circular metal tag that will be provided by Consumers Energy.

2.3.2. The existing or new pole tag number will be recorded at each pole location.

2.4. The Contractor will obtain GPS location data accurate to 2-5 meters or better for each inspected pole. GPS location data will be recorded using the WGS84 (UTM) Coordinate System as a standard. See CE Attachment B – Data Format for electronic data reporting format.

2.5. The Contractor will take one in focus picture of the inspected pole. Picture should contain in its frame all the attachments on that pole.

2.5.1. Photos shall be captured with a device capable of 5.0 megapixels or greater.

2.5.2. The image file name will contain the tag number of the pole, followed by the compass heading of the direction the camera was facing when the photo was taken. The compass heading should be specified as the four cardinal directions and the four ordinal directions (N,NE,E,SE,S,SW,W,NW)

2.5.3. Image file must be in JPEG (.jpg) format.

2.5.4. For poles that are part of a muti-pole structure, photo shall include all poles of that structure.

3. POLE TEST INSPECTION SPECIFICATIONS

3.1. Consumer Energy’s prefered pole test inspection method is a device assisted test that helps identify poor pole conditions and voids.

3.2. The Contractor shall conduct a pole test inspection of all poles eleven (11) years old or older and which have not been inspected within the last five (5) years.

3.3. Designated poles shall be tested from ground line to 6 feet above ground line.

3.4. The Contractor shall install an agreed upon inspection tag at chest height on the road side of all tested poles.

3.5. The inspection tag shall have the name of the Contractor and the year of inspection stamped into the tag.

4. BORE TEST INSPECTION SPECIFICATIONS

4.1. The Contractor will perform a bore test on poles for the following reasons:

4.1.1. The pole test indicates the pole is decaying.

4.1.2. Visual decay is present.

4.1.3. Insects appear to be in the pole.

4.1.4. The pole has been backfilled or is discolored.

4.1.5. To satisfy a doubt about a pole's condition.

4.1.6. To determine the condition of a pole which was previously reinforced.

4.2. The Contractor shall only probe the pole surface if the pole has indication of defects from the visual or pole test inspections.

4.3. The Contractor shall follow the following bore test procedure:

4.3.1. Bore where either the pole test or visual inspection indicates the weakest point. Where two points are equally weak at the same level, bore the side of the pole perpendicular to the direction of the line.

4.3.2. If the pole test indicates decay or voids near ground, excavate to a depth of 6 to 8 inches and bore downward at a 45 degree angle. For poles installed in concrete or black top, bore downward at grade level at a 45 degree angle. (Read shell thickness on the 45 degree scale.) Poles with 1" shell thickness or less shall be indicated for replacement (Section 5.3).

4.3.3. For externally damaged sections, bore both the damaged side and 180 degrees from the damaged side.

4.3.4. For insect colonies, bore weakest point found during pole test.

4.3.5. Probe bored holes with depth gauge and record shell thickness. On all poles that are bored a shell thickness recorded in the appropriate data field is required. For poles where no void is found record a NV (No Void) in the *Bore* field. Record approximent height from ground line of minimum shell thickness in *Minimum Shell Thickness Height Field*.

4.3.6. Bore HVD candidate poles at 15" and 54" above the groundline to determine if it can be reinforced. (**Note**: "Candidate" poles are poles that qualify as replacement candidates per Section 5.1.2 Report the minimum shell thickness at 15" and 54" above the groundline. Report the pole as reinforceable if there is an average 2" of shell or greater at 15" above the groundline and an average 4" shell or greater at 54" above the groundline.

4.3.7. Plug all holes with 3" treated wood plugs.

4.3.8. Bore previously reinforced poles at the top of the steel truss. Identify previously reinforced pole as a replacement candidate if less than average 4" shell.

4.3.9. When inspection is complete replace any excavated soil, tamping it firmly around the pole butt. Make a small mound of soil to compensate for settling.

4.4. Inspect the pole for surface decay.

4.5. The Contractor will install an acceptable bore tag at chest height on the road side of all poles bore tested.

5. EVALUATION CRITERIA

5.1. The Contractor shall use the following bore test criteria to identify wood pole replacement candidates:

5.1.1 HVD Line Section Criteria

Original Circumference Just Above Groundline	Reduction of Circumference At or Below Groundline (Decayed Area)	Hollow Heart Minimum Allowable Thickness of Shell At Outer Decay Location	Pole Is A Replacement Candidate If Shell Thickness Is Less Than
35"	0"	2.0"	2.0"
	2"	2.0"	2.0"
	4.4"	Solid	Solid
	Greater than 4.4"	Candidate	-
40"	0"	2.0"	2.0"
	2"	2.0"	2.0"
	4"	2.6"	2.6"
	5.1"	Solid	Solid
	Greater than 5.1"	Candidate	-
50"	0"	2.0"	2.0"
	2"	2.2"	2.2"
	4"	2.8"	2.8"
	6.3"	Solid	Solid
	Greater than 6.3"	Candidate	-
60"	0"	2.3"	2.3"
	2"	2.6"	2.6"
	4"	3.1"	3.1"
	7.6"	Solid	Solid
	Greater than 7.6"	Candidate	-
70"	0"	2.7"	2.7"
	2"	3.0"	3.0"
	4"	3.4"	3.4"
	6"	4.0"	4.0"
	8"	5.4"	5.4"
	8.9"	Solid	Solid
	Greater than 8.9"	Candidate	-
80"	0"	3.0"	3.0"
	2"	3.4"	3.4"
	4"	3.8"	3.8"
	6"	4.3"	4.3"
	8"	5.2"	5.2"
	10.1"	Solid	Solid
	Greater than 10.1"	Candidate	-

5.2. Visual inspection can be used to identify rejected poles where there is severe decay at the top of the pole or where the pole is split or has large voids above chest height or other similar conditions. On all poles rejected due to visual inspection record reason in *Comments* field.

5.3. The Contractor shall install a red tag (white arrow) on all rejected poles at chest height on the road side of the pole, and indicate proper replacement value in the *ActionRequired* field.

5.3.1. Place the red tag "arrow up" if the pole was rejected from the visual inspection.

5.3.2. Place the red tag "arrow down" if the pole was rejected from the bore test inspection.

5.4. Replacement HVD candidate poles shall not be treated with wood preserving products unless the pole is reinforceable according to the criteria in 4.3.6.

6.0 Record Keeping

6.1 If the brand date is unreadable, estimate the manufactured year, height, and class of the pole and record as such.

6.2 Any poles that were unable to be inspected shall be recorded as follows:

- No in the *Accessible* field.
- Nearby GPS coordinate in GPS coordinate field.
- Additional location information in the *LocationDescription* field (ex. 200’ N of Pole# 1234567).
- A valid reason of why the pole is inaccessible in the *Comments* field (ex. Surrounded by water).

6.3 When testing multiple pole HVD structures, indicate which pole is being tested in the *HVD Structure Number* field. Example: #556N, #556S, #556W or #556E.

6.4 If the existing HVD pole is stubbed, indicate which pole is being tested in the HVD Structure Number field. Example: #556, #556stub.

6.5 If there is a guy pole attached to a HVD pole, indicate which pole is being tested in the HVD Structure Number field. Example: #556 (T pole), #556guy.

6.6 If there is a swamp fixture attached to the pole, indicate “swamp fixture” in the foundation type field.

6.7 A HVD pole with an air-break switch in single circuit lines may not have pole numbers on them; in such cases, use the switch number on the switch handle. Switches in double circuit lines should have pole numbers on them. Indicate the air-break switch number followed by “ABS” in the HVD Structure Number field. (ex. 177ABS)

6.8 For poles in substations, record “sub” in *HVD Structure Number* field for un-numbered substation poles.

7. HVD WOOD PRESERVATIVE TREATMENT SPECIFICATIONS

7.1. The Contractor will use only those wood preservative products listed on Attachment C for treating HVD wood poles.

7.2. The Contractor shall treat all HVD poles with groundline surface decay that reduces the original circumference of the pole by 2" or more.

7.3. The following method will be used to treat HVD poles with surface decay.

7.3.1. Excavate to a depth of 18".

7.3.2. Remove all external decay by chipping and wire brushing (avoid removing any good wood).

7.3.3. Remove all shavings and decayed material from the hole and surrounding area.

7.3.4. When possible, remove all attachments and replace when bandaging or preservative application is complete (never bandage over wire molding).

7.3.5. Apply bandage or preservative application so that it extends 3" above groundline. Cover the bandage or preservative with an approved moisture carrier.

7.3.6. Replace excavated soil and tamp. Do not place solid objects such as large rocks against the pole. Backfills shall be mounded around the pole to allow for settling.

7.3.7. No debris, loose soil, etc, is to be left in the pole area and shall be properly disposed of. Replace turf removed from excavation with care in its original location.

7.4. The contractor will treat all HVD poles with internal decay except replacement candidates which are not reinforceable. The contractor will treat all HVD poles infested with termite or ant colonies that are not replacement candidates or are reinforceable candidates. The contractor will internally treat all previously reinforced HVD poles with an average 4" shell or greater at 54" above groundline. The contractor shall treat all internally decayed HVD poles with an approved preservative, and in addition, decay voids/pockets shall be treated with pentachlorophenol or liquid copper napthenate.

7.4.1. The Contractor will follow the manufacturer's labeled directions for internal treatment of wood poles.

7.4.2. All holes will be plugged with 3" treated wood plugs following internal treatment.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Pole Inspection Plan by HVD Line
Electric Distribution

Case No.: U-22070
Exhibit No.: A-155 (KKL-2)
Page: 1 of 3
Witness: KKLaFrance
Date: June 2026

Line No.	(a) Line Name	(b) Number of Poles Inspected	(c) Number of Poles Failing Inspection	(d) Cost for Pole Replacements
1	GRAND LEDGE	113	11	$ 294,800
2	LITCHFIELD	1	0	$ -
3	LOMBARD	1	0	$ -
4	WILDER	10	1	$ 26,800
5	DONTZ RD	149	14	$ 375,200
6	GREENVILLE	1	0	$ -
7	LESLIE	4	0	$ -
8	PARMA	256	24	$ 643,200
9	BELLEVUE	1	0	$ -
10	BRONSON	87	8	$ 214,400
11	NORTH ADAMS	82	8	$ 214,400
12	STOCKBRIDGE	232	22	$ 589,600
13	STOCKBRIDGE	160	15	$ 402,000
14	PARNALL	41	4	$ 107,200
15	OKEMOS	1	0	$ -
16	VENICE	97	9	$ 241,200
17	NATIONAL CITY	128	12	$ 321,600
18	NATIONAL CITY	21	2	$ 53,600
19	ALABASTER	503	48	$ 1,286,400
20	ALABASTER	8	1	$ 26,800
21	LINCOLN	44	4	$ 107,200
22	LINCOLN	44	4	$ 107,200
23	NATIONAL CITY	49	5	$ 134,000
24	LINCOLN	68	6	$ 160,800
25	ROBERTS ST	113	11	$ 294,800
26	ROBERTS ST	40	4	$ 107,200
27	PARNALL	88	8	$ 214,400
28	ROBERTS ST	10	1	$ 26,800
29	PARNALL	9	1	$ 26,800
30	NORTHPORT	54	5	$ 134,000
31	MAPLE CITY	107	10	$ 268,000
32	MAPLE CITY	29	3	$ 80,400
33	NORTHPORT	1	0	$ -
34	ROSEBUSH	95	9	$ 241,200
35	SANFORD	10	1	$ 26,800
36	CAMPUS	113	11	$ 294,800
37	SHEPHERD	130	12	$ 321,600
38	ROSEBUSH	1	0	$ -
39	WEISS	28	3	$ 80,400
40	POTTER	26	2	$ 53,600
41	POTTER	1	0	$ -
42	SALZBURG	108	10	$ 268,000
43	PATTERSON #2	1	0	$ -
44	MIDDLEVILLE	464	44	$ 1,179,200
45	EATON RAPIDS	94	9	$ 241,200
46	GRAND BLANC	70	7	$ 187,600
47	FENTON	83	8	$ 214,400
48	GRAND BLANC	98	9	$ 241,200
49	GRAND BLANC	39	4	$ 107,200
50	FENTON	2	0	$ -
51	**Sub-Total**	**3915**	**370**	**$ 9,916,000**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Pole Inspection Plan by HVD Line
Electric Distribution

Case No.: U-22070
Exhibit No.: A-155 (KKL-2)
Page: 2 of 3
Witness: KKLaFrance
Date: June 2026

	(a)	(b)	(c)	(d)
Line No.	Line Name	Number of Poles Inspected	Number of Poles Failing Inspection	Cost for Pole Replacements
1	GOLDEN	1	0	$ -
2	AUBURN	10	1	$ 26,800
3	LARKIN	58	6	$ 160,800
4	LARKIN	1	0	$ -
5	GOLDEN	1	0	$ -
6	WALDO	54	5	$ 134,000
7	JACKMAN	120	11	$ 294,800
8	JACKMAN	1	0	$ -
9	JACKMAN	69	7	$ 187,600
10	RANGER LAKE	33	3	$ 80,400
11	THOMPSON RD - GAINES	21	2	$ 53,600
12	HANOVER	312	30	$ 804,000
13	SUMMIT	5	0	$ -
14	WESTWOOD	9	1	$ 26,800
15	WESTWOOD	4	0	$ -
16	WESTWOOD	1	0	$ -
17	WESTWOOD	91	9	$ 241,200
18	WESTWOOD	101	10	$ 268,000
19	MENDON	302	29	$ 777,200
20	BRONSON	1	0	$ -
21	BRONSON	16	2	$ 53,600
22	BRONSON	205	20	$ 536,000
23	MENDON	7	1	$ 26,800
24	MENDON	17	2	$ 53,600
25	HAMILTON	115	11	$ 294,800
26	SALEM (HAMILTON - SALEM)	191	18	$ 482,400
27	METRO	18	2	$ 53,600
28	HANSEN	1	0	$ -
29	HARLEM	94	9	$ 241,200
30	SALEM (BLACK RIVER - RANSOM)	77	7	$ 187,600
31	GUN LAKE	127	12	$ 321,600
32	GUN LAKE	2	0	$ -
33	ELM ST (KELLOGG - VERONA)	37	4	$ 107,200
34	RIGGSVILLE - LIVINGSTON	33	3	$ 80,400
35	HASKELITE	9	1	$ 26,800
36	DAVISON (DORT - IRISH ROAD)	205	20	$ 536,000
37	DAVISON (DELANEY - IRISH ROAD)	1	0	$ -
38	OVID	82	8	$ 214,400
39	CALKINS	143	14	$ 375,200
40	THOMAS	7	1	$ 26,800
41	CASCADE	37	4	$ 107,200
42	SHAFFER	39	4	$ 107,200
43	LESCOA	10	1	$ 26,800
44	SARANAC	164	16	$ 428,800
45	LAKE ODESSA	4	0	$ -
46	RIVERDALE	358	34	$ 911,200
47	RIVERDALE	21	2	$ 53,600
48	GILSON	71	7	$ 187,600
49	KARN - GARFIELD	1	0	$ -
50	MANCELONA	1	0	$ -
51	**Sub-Total**	**3288**	**317**	**$ 8,495,600**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Pole Inspection Plan by HVD Line
Electric Distribution

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Line No.	(a) Line Name	(b) Number of Poles Inspected	(c) Number of Poles Failing Inspection	(d) Cost for Pole Replacements
1	ANGELL	200	19	$ 509,200
2	MANCELONA	2	0	$ -
3	MANCELONA	1	0	$ -
4	MANCELONA	35	3	$ 80,400
5	BOARDMAN - HODENPYL	76	7	$ 187,600
6	**Sub-Total**	**314**	**29**	**$ 777,200**
7	**Total**	**7517**	**716**	**$ 19,188,800**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2026-2027 Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1		Greenville	375	1.8	Miles	Line Rebuilds	Customer*Minutes Avoided	40,406	Greenville
2		Bellevue	164	0.2	Miles	Line Rebuilds	Customer*Minutes Avoided	6,095	Calhoun County
3		Erie	5,674	8.0	Miles	Line Rebuilds	Customer*Minutes Avoided	204,608	Monroe County
4		Nashville	7,747	11.2	Miles	Line Rebuilds	Customer*Minutes Avoided	138,261	Barry County
5		Wayland	624	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	7,778	Allegan County
6		Wirtz Rd	4,827	8.0	Miles	Line Rebuilds	Customer*Minutes Avoided	435,498	Gladwin Counties
7		Morrice	4,087	6.3	Miles	Line Rebuilds	Customer*Minutes Avoided	415,951	Shiawassee County
8		Niagara	210	0.0	Miles	Line Rebuilds	Customer*Minutes Avoided	1,088	Saginaw
9		Hodenpyl	2,530	3.9	Miles	Line Rebuilds	Customer*Minutes Avoided	83,179	Wexford County
10		Golden	457	0.3	Miles	Line Rebuilds	Customer*Minutes Avoided	3,420	Bay County
11		Golden	196	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	1,140	Bay County
12		Union St	6,223	0.4	Miles	Line Rebuilds	Customer*Minutes Avoided	11,388	Grand Traverse County
13		Golden	292	0.5	Miles	Line Rebuilds	Customer*Minutes Avoided	1,603	Bay County
14		Stover Line	210	0.0	Miles	Line Rebuilds	Customer*Minutes Avoided	1,212	Antrim County
15		Union City	911	1.0	Miles	Line Rebuilds	Customer*Minutes Avoided	-	Calhoun County
16		Hughes Rd	196	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	2,652	Calhoun County
17		Niagara 2	259	0.4	Miles	Line Rebuilds	Customer*Minutes Avoided	5,442	Saginaw
18		Union City 2	4,522	7.9	Miles	Line Rebuilds	Customer*Minutes Avoided	-	Calhoun County
19		Nashville 2	454	0.7	Miles	Line Rebuilds	Customer*Minutes Avoided	8,641	Hastings
20		Nashville 3	16	0.0	Miles	Line Rebuilds	Customer*Minutes Avoided	-	Hastings
21		Grand Valley	2,465	3.8	Miles	Line Rebuilds	Customer*Minutes Avoided	13,878	Kent County
22		Walker	1,362	2.1	Miles	Line Rebuilds	Customer*Minutes Avoided	76,935	Kent County
23		Merrill	2,984	4.6	Miles	Line Rebuilds	Customer*Minutes Avoided	43,206	Saginaw County
24		Cement City	2,206	3.4	Miles	Line Rebuilds	Customer*Minutes Avoided	105,101	Jackson County
25		Cooper	3,049	4.7	Miles	Line Rebuilds	Customer*Minutes Avoided	138,180	Kalamazoo County
26		Morrice	2,919	4.5	Miles	Line Rebuilds	Customer*Minutes Avoided	148,554	Shiawassee County
27		Shelby	3,438	5.3	Miles	Line Rebuilds	Customer*Minutes Avoided	48,845	Muskegon and Oceana Counties
28		Wealthy-Ellsworth #2 & Wealthy-Lagrave	1,100	0.6	Miles	Line Rebuilds	Customer*Minutes Avoided	3,222	Grand Rapids
29		Niagara 3	454	0.7	Miles	Line Rebuilds	Customer*Minutes Avoided	9,524	Saginaw
30			**59,951**	**80.6**	Miles	Line Rebuilds	Customer*Minutes Avoided	**1,955,806**	
31		Burr Oak	7	6.9	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	74,790	Branch and St Joseph Counties
32		Bellevue	39	10.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	326,061	Calhoun County
33		Bellevue 2	20	5.9	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	179,791	Calhoun County
34		Eaton Rapids	345	5.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	133,175	Eaton County
35		Eaton Rapids 2	274	4.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	106,540	Calhoun and Jackson Counties
36		Ithaca	689	10.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	210,304	Gratioit County
37		Ithaca 2	193	2.8	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	58,885	Gratioit County
38		Frost	65	1.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	119,196	Clare County
39		Frost 2	1,860	27.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	946,553	Clare County
40		Cannonsburg	438	4.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	78,326	Kent County
41		Merrill	555	6.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	111,771	Gratioit County
42		Ovid	560	6.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	180,540	Clinton County
43		Coleman	373	4.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	154,260	Midland County
44		Silicon	364	3.9	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	63,648	Saginaw County
45		Pentwater	149	1.6	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	27,800	Mason County
46		Squires	93	1.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	23,280	Hillsdale County
47		Glen Oaks	298	3.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	53,965	St Joseph County
48		Boardman - Hodenpyl	494	5.3	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	187,594	Wexford County
49		Kent City	159	1.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	42,432	Kent City
50		Oakwood	149	1.6	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	65,344	Kalamazoo
51		Dort - AC	224	2.4	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	121,452	Burton
52		**Pole Top Rehabilitation Subtotal**	**7,348**	**115.3**				**3,265,704**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1		Wirtz Rd	39	0.4	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	16,762	Gladwin
2		Stadium	229	2.8	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	31,766	Kalamazoo
3		Calkins	149	1.6	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	49,740	Flint
4		Cascade	187	2.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	47,980	Grand Rapids
5		Cascade 2	504	5.4	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	64,773	Grand Rapids
6		Jackman	401	4.3	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	102,684	Monroe County
7		Greenville	140	1.5	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	42,090	Montcalm County
8		Greenville 2	159	1.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	23,851	Greenville
9		Greenville 3	112	1.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	16,836	Greenville
10		Greenville 4	485	5.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	116,730	Montcalm County
11		**Pole Top Rehabilitation Subtotal**	**2,405**	**26.1**				**513,212**	
12		**Pole Top Rehabilitation Total**	**9,753**	**141.4**				**3,778,916**	
13		Pole Replacements	**40,966**	1655	Poles	Pole Replacements	Customer*Minutes Avoided	**2,117,883**	Various locations statewide
14		Switch Replacements	**8,468**	65	Switches	Switch Replacements	Customer*Minutes Avoided	**66,544**	Various locations statewide
15		Pole Top Assembly Replacement	**6,842**	800	PTAs	Pole Top Assembly Replacements	Customer*Minutes Avoided	**1,023,750**	Various locations statewide
16		Line Sensors	**2,374**	208	Sensor Loc	Line Sensor Deployment	Improve reliability through increased outage detection		Various locations statewide
17		Real Estate	**7,331**			Right of Way Acquisition	Procure Right of Way needed to support projects		Various locations statewide
18		**HVD Lines Reliability Total**	**135,685**					**8,942,899**	

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Substation Reliability	WD1090 Scott Lk, Repl Breakers & Switches	97	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	8,023	Allegan
2		WD0175 East Genesee Repl 3 Breakers	140	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	8,023	Saginaw
3		WD0940 Barry Repl Brkrs CSW SWs PTs	614	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	10,697	Barry
4		WD1242 Breton, Repl 5 OCBs	715	5	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	13,371	Kent
5		WD0727 Burlingame Sub, Repl VSW	159	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Maintain System Voltage		Kent
6		WD0605 Wexford, Repl 256 Varmaster VSW	187	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Maintain System Voltage		Wexford
7		WD0596 Frame Plant - Repl 2 Brkrs	300	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	5,349	Genesee
8		WD0560 Riverview Replace 1077 Breaker	400	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,674	Kalamazoo
9		WD0956 Deja Replace 4 Breakers	1,000	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	10,697	Montcalm
10		WD0387 Dort Replace 156 Varmaster VSW	550	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Maintain System Voltage		Genesee
11		WD0387 Dort Replace 3 Gas Breakers	850	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	8,023	Genesee
12		WD0959 Beveridge Replace 4 Gas Breakers	1,200	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	10,697	Genesee
13		WD0191 Crotty Repl 3 Breakers	575	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	5,349	Bay
14		WD0286 Verona Rp 2 Breakers	930	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,674	Calhoun
15		WD1002 Shaffer Replace 6 Breakers, 5 Switches, LAs	2,181	6	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	16,046	Kent
16		WD0266 Island Road Repl 256 VSW	527	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Maintain System Voltage	624	Eaton
17		WD0589 Thornapple Replace 156 Varmaster VSW	1,844	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Maintain System Voltage		Kent
18		WD0266 Island Road Replace 4 Gas Breakers, PTs	2,105	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	10,697	Eaton
19		WD0861 Race Street Repl RTU	27	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Kent
20		WD0064 Beecher Replace RTU/T1	52	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Lenawee
21		WD0958 Layton Replace Fence	400	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Saginaw
22		WD0123 Grout Replace Fence	200	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Gladwin
23		WD1367 Thompson Road Replace RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Ionia
24		WD1123 Felch Road Replace RTU/T1	390	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Newaygo
25		WD0400 Whiting Replace RTU/T1	420	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Monroe
26		**HVD Substations Reliability Subtotal**	**16,033**						

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Consumers Energy Company
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Substations Reliability	WD1220 Bass Creek Replace Obsolete #1 Cap Bank Controller	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Ottawa
2		WD0387 Dort Replace Fence	400	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Genesee
3		WD0573 Ohman Road Install Mobile Pad	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Osceola
4		WD1214 Gleaner Replace RTU/T1	230	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Saginaw
5		WD0095 Croton Replace RTU/T1	315	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Newaygo
6		WD0892 Manlius Replace RTU/T1	165	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Allegan
7		WD0152 Cement City Replace RTU/T1	170	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Jackson
8		WD0684 Iosco Replace RTU/T1	265	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Iosco
9		WD0600 Cornell Replace RTU/T1	215	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Shiawassee
10		WD0585 Chase Replace RTU/T1	240	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Lake
11		WD1203 Vrooman Replace RTU/T1	335	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Jackson
12		WD0428 Guardian Install Mobile Pad	62	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Calhoun
13		WD0208 Pasadena Watershed Mitigation	80	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Genesee
14		WD0195 Weadock Replace Gate	40	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Substation Security		Bay
15		WD1083 Summerton Replace RTU/T1	225	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Isabella
16		WD1090 Scott Lake Replace RTU/T1	240	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Allegan
17		WD0286 Verona Repl Fence, Lighting	298	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Substation Security		Calhoun
18		WD0266 Island Road Replace Fence And Lighting	500	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Eaton
19		WD0151 Delhi, Relblty Repl 17 Switches	295	17	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	34,808	Ingham
20		WD1257 Simpson Replace 1085 Switches	70	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	2,048	St Joseph
21		WD0170 Harvey St Repl 1085 Switches	60	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	2,048	Kent
22		WD0387 Dort Replace 8 Switches	520	8	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	16,380	Genessee
23		WD0364 Iron Street Replace 2 MOABS	300	2	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	4,095	Genesee
24		WD1523 Sinclair - Repl Batt & Working Space	65	1	Projects	Replacement of substation equipment imminent failures	System Operability		Kent
25		WD0958 Layton Replace Gates	95	2	Projects	Replacement of substation equipment imminent failures	Substation Security		Saginaw
26		**HVD Substations Reliability Subtotal**	**5,385**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Substation Reliability	WD0074 Hudson Repl Battery	75	1	Projects	Replacement of substation equipment imminent failures	System Operability		Lenawee
2		WD0930 Salt Street Replace Battery	75	1	Projects	Replacement of substation equipment imminent failures	System Operability		Saginaw
3		WD0123 Grout Repl Battery Into New Cce + Cap #1 Controller	320	1	Projects	Replacement of substation equipment imminent failures	System Operability		Gladwin
4		WD0362 Washington Replace Moloney SPT	65	1	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	4,800	Mason
5		WD0088 Quincy Replace Battery	90	1	Projects	Replacement of substation equipment imminent failures	System Operability		Branch
6		WD0958 Layton Repl TB1 N2 Cabinet	25	1	Equipment	Replacement of substation equipment imminent failures	System Operability		Saginaw
7		WD0232 Diesel Replace South Bus PTs	40	3	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	14,400	Kent
8		WD1214 Gleaner Replace Moloney SPT	150	1	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	4,800	Saginaw
9		WD0074 Hudson Replace Moloney SPT	65	1	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	4,800	Lenawee
10		WD0433 Four Mile Repl Battery + Cap #2 Controller	375	1	Projects	Replacement of substation equipment imminent failures	System Operability		Kent
11		WD0095 Croton Control House Improvement	800	0	Projects	Replacement of substation equipment imminent failures	System Operability		Newaygo
12		WD0116 Hurley Replace Moloney PT	65	1	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	4,800	Genesee
13		WD0701 Walnut Replace Battery	75	1	Projects	Replacement of substation equipment imminent failures	System Operability		Genesee
14		WD1065 Fourteenth Street Replace Battery	75	1	Projects	Replacement of substation equipment imminent failures	System Operability		Genesee
15		WD0212 Phillips Repl Battery, Charger	75	1	Projects	Replacement of substation equipment imminent failures	System Operability		Kalamazoo
16		WD0023 Blinton Repl Battery	100	1	Projects	Replacement of substation equipment imminent failures	System Operability		Genesee
17		WD0341 Potter Replace Battery	100	1	Projects	Replacement of substation equipment imminent failures	System Operability		Saginaw
18		WD2058 Disposal Plant Repl 2 Pt	100	2	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	9,600	Saginaw
19		WD1249 Algoma Replace Battery	150	1	Projects	Replacement of substation equipment imminent failures	System Operability		Kent
20		WD0979 Halsey Replace Battery	300	1	Projects	Replacement of substation equipment imminent failures	System Operability		Oakland
21		WD0951 Looking Glass Repl Battery Into New CCE	300	1	Projects	Replacement of substation equipment imminent failures	System Operability		Ingham
22		WD0235 Beals Rd Replace Station Battery, Station Power	300	1	Projects	Replacement of substation equipment imminent failures	System Operability		Kent
23		Emergent Equipment Replacements (Bushings, Arrestors, Switches)	375	8	Projects	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	192,000	Various
24		WD0792 Middleville Repl O+C Bushings	216	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Barry
25		**HVD Substations Reliability Subtotal**	**4,311**						
26		**HVD Substations Reliability Total**	**25,729**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	Transformer Bank Replacements and Substation Rebuilds	WD1722 BUSKIRK NEW 138/46 KV BULK SUB	2485	1	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	78,624	Allegan
2		WD1800 ARMORY NEW 138/46KV SUB TB2	3220	0	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	78,624	Gratiot
3		WD1815 ROYAL NEW SUB	4633	0	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	78,624	Jackson
4		WD0053 LENAWEE STAMPING REBUILD	57	0	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	7	Lenawee
5		WD0443 DEARBORN MACHINE REBUILD	50	0	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	7	Muskegon
6		WD1323 ORCHARD ROAD RPL TB1 & TB2	2170	2	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	2	Midland
7		WD1109 WACKERLY REPLACE TB NO.1	611	1	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Midland
8		WD0596 FRAME PLANT - REPL TB2 & TB3	1000	2	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	2	Genesee
9		WD1396 STEERING GEAR REPL TB #1,2,3	962	3	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	4	Saginaw
10		WD0354 ALMA PRODUCTS RPL TB1	1327	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Gratiot
11		WD0191 CROTTY REPL TB3	2000	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Bay
12		WD0670 STOVER REPL TB1	3574	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Antrim
13		WD0967 McNally repl TB #2	100	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Charlevoix
14		WD1073 OGEMAW REPL TB1	100	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Ogemaw
15		WD1214 GLEANER REPLACE TB NO.1	100	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Saginaw
16		WD1489 VERNON REPLACE TB NO.1	100	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Isabella
17		WD1180 WOLVERINE REPL TRANS	93	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Calhoun
18		WD0384 JACKSON RCF REPL TRANS	50	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Jackson
19		WD0095 CROTON REPL TRANS #3	288	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Newaygo
20		WD0660 MCGULPIN REPL TRANS #1 & #2	576	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Emmet
21		WD0167 HSC REPL TRANS NO.3	288	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Saginaw
22		WD0161 ROCHESTER PROD REPL TRANS#2	88	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Ottawa
23		WD0738 PIPE LINE REPL TRANS #1	113	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Bay
24		WD1445 BIG CHIEF REPL TRANS #3	77	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Bay
25		WD0428 GUARDIAN REPL TRANS #2	72	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Calhoun
26		WD0428 GUARDIAN REPL TRANS #3	44	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Calhoun
27		WD1243 AMWAY REPL TRANS	0	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Kent
28		WD0926 ANN STREET REPL TRANS	102	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Kent
29		WD0159 BERMAN STEEL REPL TRANS	49	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Kent
30		WD0077 MARATHON REPL TRANS	50	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Monroe
31		WD0152 CEMENT CITY REPL TRANS	140	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Jackson
32		WD1170 SAMARIA TRANS TB2	140	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Monroe
33		WD0929 EXTRUDED METALS REPL TRANS	148	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Kent
34		WD1253 CADILLAC MALLEABLE REPL TRF #1	42	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Wexford
35		WD1450 UPJOHN RESEARCH REPL TRANS #2	230	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Kalamazoo
36		WD0610 BINGHAM REPL TRANS #1	403	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Clinton
37		WD0956 DEJA REPL TRANS #1	140	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Montcalm
38		WD1085 AMBER REPL TRANS #1	220	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Mason
39		WD0892 MANLIUS REPL TRANS NO.2	140	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Allegan
40		WD0085 ELM STREET REPL TRANS #4	220	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Calhoun
41		WD0286 VERONA REPL TRANS #1	403	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Calhoun
42		**Transformer Bank Replacements and Substation RebuildsTotal:**	**26,605**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Benefit Type	(h) Benefit	(i) Location
	Reliability								
1	LVD Substations Reliability	BUCKEYE	2,150	1	Project	New Substations	Reliability - outage minutes avoided	130,596	Gladwin
2		HOUGHTON LAKE	7,222	1	Project	New Substations	Reliability - outage minutes avoided	6,132,240	Roscommon
3		IARGO	2,395	1	Project	New Substations	Reliability - outage minutes avoided	226,800	Iosco
4		MONUMENT	150	1	Project	New Substations	Reliability - outage minutes avoided	465,480	Iosco
5		REA ROAD	1,764	1	Project	New Substations	Reliability - outage minutes avoided	372,600	Iosco
6		EAST TAWAS	2,600	1	Project	Rebuild Substations	Reliability - outage minutes avoided	4,112,640	Iosco
7		ONSTED	374	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Lenawee
8		TWIN LAKE	736	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Muskegon
9		WALDRON	2,339	1	Project	Rebuild Substations	Reliability - outage minutes avoided	1,057,320	Hillsdale
10		ALCONA DAM	683	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Alcona
11		GREENBUSH	654	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Alcona
12		GREENSPIRE	620	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Kalamazoo
13		MANTON	636	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Wexford
14		NORTH MUSKEGON	906	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Muskegon
15		OAK STREET	1,331	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Jackson
16		PEWAMO	683	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Clinton
17		PIERSON	394	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Montcalm
18		PULLMAN	636	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Allegan
19		ROUND LAKE	292	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Lenawee
20		THORNAPPLE	906	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Kent
21		WESTPHALIA	418	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Clinton
22		WITHEY LAKE	683	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Ogemaw
23		MOBILE 15	398	0	Project	Mobile Substations	Reliability - outage minutes avoided	-	Statewide
24		MOBILE 26	1,817	0	Project	Mobile Substations	Reliability - outage minutes avoided	-	Statewide
25		MOBILE 28	2,953	0	Project	Mobile Substations	Reliability - outage minutes avoided	-	Statewide
26		MOBILE 29	2,215	0	Project	Mobile Substations	Reliability - outage minutes avoided	-	Statewide
27		BEAVER	160	1	Project	Animal Mitigation	Reliability - outage minutes avoided	195,720	Bay
28		BELDEN ROAD	160	1	Project	Animal Mitigation	Reliability - outage minutes avoided	120	Jackson
29		BRIGDEN	140	1	Project	Animal Mitigation	Reliability - outage minutes avoided	120	Calhoun
30		CAMDEN	160	1	Project	Animal Mitigation	Reliability - outage minutes avoided	157,080	Hillsdale
31		DISPOSAL PLANT	180	1	Project	Animal Mitigation	Reliability - outage minutes avoided	120	Saginaw
32		FLUSHING PARK	160	1	Project	Animal Mitigation	Reliability - outage minutes avoided	120	Genesee
33		FREEPORT	140	1	Project	Animal Mitigation	Reliability - outage minutes avoided	160,440	Barry
34		GREENBUSH	140	1	Project	Animal Mitigation	Reliability - outage minutes avoided	226,440	Alcona
35		HASTINGS	297	1	Project	Animal Mitigation	Reliability - outage minutes avoided	784,560	Barry
36		HENDERSON PUMPING	160	1	Project	Animal Mitigation	Reliability - outage minutes avoided	120	Genesee
37		MCKINLEY	140	1	Project	Animal Mitigation	Reliability - outage minutes avoided	120	Genesee
38		MCNALLY	180	1	Project	Animal Mitigation	Reliability - outage minutes avoided	480	Charlevoix
39		MIDLAND TREATMENT	220	1	Project	Animal Mitigation	Reliability - outage minutes avoided	120	Midland
40		SHANTY CREEK	160	1	Project	Animal Mitigation	Reliability - outage minutes avoided	60,720	Antrim
41		TERRACE	297	1	Project	Animal Mitigation	Reliability - outage minutes avoided	266,400	Muskegon
42		TWIN LAKE	180	1	Project	Animal Mitigation	Reliability - outage minutes avoided	255,600	Muskegon
43		VENICE	180	1	Project	Animal Mitigation	Reliability - outage minutes avoided	117,240	Shiawassee
44		VENTURA	200	1	Project	Animal Mitigation	Reliability - outage minutes avoided	120	Ottawa
45		WHITE ROAD	160	1	Project	Animal Mitigation	Reliability - outage minutes avoided	120	Muskegon
46		WURTSMITH	180	1	Project	Animal Mitigation	Reliability - outage minutes avoided	213,480	Iosco
47		SILVER LAKE	360	6	Regulators	Regulator Replacements	Service Quality; number of customers	2,891	Grand Traverse
48	**LVD Substations Reliability Subtotal**		**39,904**					**14,939,807**	

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	Reliability								
1	LVD Substations Reliability	BELKNAP	344	1	Project	Transformer Replacements	Reliability - outage minutes avoided	574,560	Allegan
2		BROADMOOR TB3	1,307	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
3		BROADMOOR TB4	1,307	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
4		LAGRAVE	100	1	Project	Transformer Replacements	Reliability - outage minutes avoided	25,200	Kent
5		SARANAC	435	1	Project	Transformer Replacements	Reliability - outage minutes avoided	267,660	Ionia
6		SHERMAN	100	1	Project	Transformer Replacements	Reliability - outage minutes avoided	368,280	Iosco
7		ALLENDALE PUMPING	395	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Ottawa
8		BAILEY	379	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Muskegon
9		BAYBERRY	684	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
10		EAST GRANT	379	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Newaygo
11		FOREST GROVE	906	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Ottawa
12		FRANKFORT	387	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Benzie
13		FRANKFORT	258	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Benzie
14		FROST	379	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Clare
15		FULTON	674	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
16		HOPKINS	359	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Allegan
17		KELLOGGSVILLE TB1	674	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
18		KELLOGGSVILLE TB2	674	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
19		KENDALL	407	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kalamazoo
20		LAKE SHORE	245	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Ottawa
21		LEE STREET	906	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
22		MAYFAIR	407	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Genesee
23		MORRELL	709	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Jackson
24		MUSKEGON HEIGHTS	906	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Muskegon
25		MUSKEGON HEIGHTS	906	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Muskegon
26		MUSKEGON TREATMENT	395	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Muskegon
27		MUSKEGON TREATMENT	395	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Muskegon
28		NORTH KENT	407	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
29		NORTH KENT	412	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
30		READING	381	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Hillsdale
31		RED CEDAR	474	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Ingham
32		RICHLAND	359	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kalamazoo
33		SHERIDAN	359	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Montcalm
34		TRAVIS	636	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kalamazoo
35		WALNUT	485	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Genesee
36		WILLIAMS	636	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Allegan
37		WILLIAMS	636	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Allegan
38		ATLAS	214	1	Project	DSCADA Projects	Reliability - outage minutes avoided	333,960	Genesee
39		BALDWIN	1,155	1	Project	DSCADA Projects	Reliability - outage minutes avoided	239,880	Lake
40		BEERS	321	1	Project	DSCADA Projects	Reliability - outage minutes avoided	339,120	Genesee
41		CARROLLTON	488	1	Project	DSCADA Projects	Reliability - outage minutes avoided	149,520	Saginaw
42		ENSLEY	865	1	Project	DSCADA Projects	Reliability - outage minutes avoided	175,560	Newaygo
43		HOGSBACK	739	1	Project	DSCADA Projects	Reliability - outage minutes avoided	791,040	Ingham
44		MASON	629	1	Project	DSCADA Projects	Reliability - outage minutes avoided	391,560	Ingham
45		NORTHERN FIBRE	288	1	Project	DSCADA Projects	Reliability - outage minutes avoided	156,480	Ottawa
46		ROCKFORD	233	1	Project	DSCADA Projects	Reliability - outage minutes avoided	424,080	Kent
47		SHERMAN	629	1	Project	DSCADA Projects	Reliability - outage minutes avoided	40,920	Iosco
48		SWARTZ CREEK	188	1	Project	DSCADA Projects	Reliability - outage minutes avoided	476,880	Genesee
49		WOODWARD	216	1	Project	DSCADA Projects	Reliability - outage minutes avoided	191,520	Wexford
50		**LVD Substations Reliability Subtotal**	**25,760**					**4,946,220**	
51		**LVD Substations Reliability Total**	**65,664**					**19,886,027**	

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	Reliability								
1	LVD Substations Rehabilitation	BALLENGER	620	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Genesee
2		BELLAIRE	1,188	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	1,198,800	Antrim
3		CONKLIN PARK	978	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	1,898,640	Newaygo
4		COOPER	557	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Kalamazoo
5		CROFTON	908	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	5,400	Kalkaska
6		FOUNTAIN	804	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	644,760	Calhoun
7		FRASER PUMPING	452	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Bay
8		GMI	644	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Genesee
9		GOLDEN	666	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Midland
10		INGHAM	225	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	2,238,840	Jackson
11		JUNCTION PUMPING	324	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Bay
12		KINGSLEY	1,980	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	3,259,440	Grand Traverse
13		LIBERTY	947	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	232,560	Calhoun
14		LYONS	189	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Ionia
15		MAYFAIR	666	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Genesee
16		NESTROM	647	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Muskegon
17		OTTAWA BEACH	638	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Ottawa
18		SAGINAW STREET	851	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Genesee
19		STANTON	2,267	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	1,049,760	Montcalm
20		WILSON	825	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	1,080	Kent
21		BLACKMAN	60	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	820,620	Jackson
22		CAMELOT LAKE	1,783	1	Project	Equipment Replacement and Regulatory	Regulatory Compliance	-	Midland
23		CONVIS	60	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	390,780	Calhoun
24		DUTTON	150	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	976,320	Kent
25		FAIRBANKS	1,702	0	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	-	Kent
26		KIPP ROAD	746	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	848,700	Ingham
27		LAGRAVE	800	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	104,400	Kent
28		LAKE CITY	60	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	1,127,160	Missaukee
29		LAKE SHORE	188	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	180	Ottawa
30		LETTS ROAD	1,485	1	Project	Equipment Replacement and Regulatory	Regulatory Compliance	-	Midland
31		MUSKEGON HEIGHTS	300	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	583,380	Muskegon
32		NEFF ROAD	720	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	577,440	Genesee
33		NINETEEN MILE	1,481	1	Project	Equipment Replacement and Regulatory	Regulatory Compliance	-	Mecosta
34		NORTHERN FIBRE	579	1	Project	Equipment Replacement and Regulatory	Regulatory Compliance	-	Ottawa
35		OHMAN ROAD	1,270	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	3,086,640	Osceola
36		PORT CALCITE	1,005	0	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	-	Presque Isle
37		STEELCASE	1,825	1	Project	Equipment Replacement and Regulatory	Regulatory Compliance	-	Kent
38		WILLIAMS	413	1	Project	Equipment Replacement and Regulatory	Regulatory Compliance	-	Allegan
39		**LVD Substations Rehabilitation Total**	**31,000**	**25**				19,044,900	

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	Reliability								
1		ELEANOR ST ELEC	700	1	Project	Obsolete or Needed Electrical	Kalamazoo	Customer-outage-minutes avoided	14,944
2		POST TAVERN VAULT DF	600	1	Project	Deadfronting	Battle Creek	Worker Safety	-
3		WOLVERINE TO POST TAVERN CIVIL	1,000	1	Project	Obsolete or Needed Civil	Battle Creek	Customer-outage-minutes avoided	-
4		WOLVERINE TO POST TAVERN ELEC	500	1	Project	Obsolete or Needed Electrical	Battle Creek	Customer-outage-minutes avoided	20,157
5		W WEST FIRST STREET VAULT	100	1	Project	Deadfronting	Flint	Worker Safety	-
6		CRESCENT LAFAYETTE CIVIL	1,430	1	Project	Obsolete or Needed Civil	Grand Rapids	Customer-outage-minutes avoided	-
7		ELLSWORTH RECONDUCTOR	600	1	Project	Obsolete or Needed Electrical	Grand Rapids	Customer-outage-minutes avoided	103,626
8		BOB RECONDUCTOR SVC	100	1	Project	Obsolete or Needed Electrical	Grand Rapids	Customer-outage-minutes avoided	880
9		WILLIAMS VAULT DF	300	1	Project	Deadfronting	Grand Rapids	Worker Safety	-
10		**Metro Reliability Total**	**5,330**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Metro Rehabilitation	CORTLAND MECHANIC TO JACKSON CIVIL PH 2 PREWORK	500	1	Project	Vault or Manhole Rehabilitation	Jackson	Customer-outage-minutes avoided	-
2		CORTLAND MECHANIC TO JACKSON ELEC PH 2 PREWORK	225	1	Project	Vault or Manhole Rehabilitation	Jackson	Customer-outage-minutes avoided	-
3		NEW FIRESTONE VAULT CIVIL	350	1	Project	Vault or Manhole Rehabilitation	Grand Rapids	Customer-outage-minutes avoided	-
4		NEW FIRESTONE VAULT ELEC	250	1	Project	Vault or Manhole Rehabilitation	Grand Rapids	Customer-outage-minutes avoided	11,059
5		FIRESTONE RISER ELEC	86	1	Project	Vault or Manhole Rehabilitation	Grand Rapids	Customer-outage-minutes avoided	9,680
6		E 1ST STREET VAULT CIVIL	755	1	Project	Vault or Manhole Rehabilitation	Flint	Customer-outage-minutes avoided	-
7		E 1ST STREET VAULT ELEC	637	1	Project	Vault or Manhole Rehabilitation	Flint	Customer-outage-minutes avoided	41,800
8		GENESEE CTY COURTHOUSE ELEC	150	1	Project	Vault or Manhole Rehabilitation	Flint	Customer-outage-minutes avoided	440
9		**Metro Rehabilitation Total**	**2,953**						

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	(a)	(b)	(c)	(d)	(e)	(f)		
Line No.	**Sub-Program**	**Project Description, Line, Substation, or Location**	**Projected Period Spending (Bridge)**	**Units**	**Unit Type**	**Investment Category**	**Benefit Type**	**Location**
1	System Protection	MAUMEE	404	4	Relay Packages	Line Exit Relay Replacements	Compliance	Adrian
2		HARVEY STREET	525	10	Relay Packages	Line Exit Relay Replacements	Compliance	Grand Rapids
3		BRETON	400	13	Relay Packages	Line Exit Relay Replacements	Safety	Grand Rapids
4		FRAME PLANT	672	7	Relay Packages	Line Exit Relay Replacements	Compliance	Flint
5		ENGINE PLANT	100	1	Relay Packages	Line Exit Relay Replacements	Safety	Flint
6		CROTTY	690	5	Relay Packages	Line Exit Relay Replacements	Safety	Bay City
7		SHAFFER	1,529	7	Relay Packages	Line Exit Relay Replacements	Safety	Grand Rapids
8		BARRY	273	4	Relay Packages	Line Exit Relay Replacements	Safety	Hastings
9		EAST GENESEE	440	3	Relay Packages	Line Exit Relay Replacements	Safety	Saginaw
10		BAUM STREET	155	4	Relay Packages	Line Exit Relay Replacements	Compliance	Saginaw
11		WASHTENAW	250	1	Relay Packages	Line Exit Relay Replacements	Safety	Chelsea
12		TROWBRIDGE	21	-	Relay Packages	Line Exit Relay Replacements	Compliance	Allegan
13		VEVAY	100	1	Relay Packages	Line Exit Relay Replacements	Safety	Mason
14		STRONACH	380	3	Relay Packages	Line Exit Relay Replacements	Safety	Manistee
15		**System Protection Total:**	**5,939**					

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Bridge)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Lines and Subs Capacity	LN006A BULLOCK-SHALE RBLD STR #6936 *05	30	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Saginaw Co.
2	HVD Lines and Subs Capacity	Cobb Substation - New METC Chopin Station Coordination	1,400	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Muskegon Co.
3	HVD Lines and Subs Capacity	LN100AB BENSTON SPUR 1.8 MI 138kV LN *08 (associated with Cobb-Dupont-White L	73	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Muskegon Co.
4	HVD Lines and Subs Capacity	WD0131 GREY IRON INST AUX CTS FOR METC *05	350	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Saginaw Co.
5	HVD Lines and Subs Capacity	Hodenpyl Substation High-Side Rack Reconfiguration	190	1	Project(s)	. Coordination with Transmission	Procure Right of Way needed to support projects	N/A	Wexford Co.
6	HVD Lines and Subs Capacity	LN77A BINGHAM-MARQUETTE METC STR REPL *5	390	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Clinton Co.
7	HVD Lines and Subs Capacity	Port Sheldon Substation - Replace 199 MOABS-SOGS with 138 kV Circuit Switcher and	618	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Ottawa Co.
8	HVD Lines and Subs Capacity	WD0565 HOLLAND ROAD INSTALL AUX CTS *05	350	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Isabella Co.
9	HVD Lines and Subs Capacity	WD0730 WARREN INST CKT SWR METC RLY *05	300	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Midland Co.
10	HVD Lines and Subs Capacity	WD0266 ISLAND RD INST CKT SWRS METC *05	1,395	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Eaton Co.
11	HVD Lines and Subs Capacity	WD0438 DOW CORNING INSTALL AUX CTS *05	15	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Saginaw Co.
12	HVD Lines and Subs Capacity	WD1083 SUMMERTON METC RELAY COORD *05	1,055	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Isabella Co.
13	HVD Lines and Subs Capacity	WD1213 EUREKA METC RLY CHANGES *08	342	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Montcalm Co.
14	HVD Lines and Subs Capacity	Wealthy Street Substation - New METC Snowy Station Coordination	2,224	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Kent Co.
15	HVD Lines and Subs Capacity	WD0940 BARRY WORKING SPACE *02	321	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Barry Co.
16	HVD Lines and Subs Capacity	Churchill Substation - Add 291 Air Break Switch	88	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Ingham Co.
17	HVD Lines and Subs Capacity	WD0956 DEJA WORKING SPACE *02	560	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Montcalm Co.
18	HVD Lines and Subs Capacity	Delaney Working Space	722	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Genesee Co.
19	HVD Lines and Subs Capacity	WD0151 DELHI RP PANELS WORKING SPACE *02	260	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Ingham Co.
20	HVD Lines and Subs Capacity	Felch Rd Working Space	543	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Newaygo Co.
21	HVD Lines and Subs Capacity	Hughes Rd Line Rebuild	475	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Branch Co.
22	HVD Lines and Subs Capacity	LN028JJ BATH RBLD 0.96 MILES 3/0 % *05	900	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Ingham Co.
23	HVD Lines and Subs Capacity	LN104G OVID 46KV RELO 5511 MOAB *13	170	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Clinton Co.
24	HVD Lines and Subs Capacity	WD0951 LOOKING GLASS WORKING SPACE *02	1,100	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Clinton Co.
25	HVD Lines and Subs Capacity	Manchester 46 kV Line – Pole replacements	368	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Jackson Co.
26	HVD Lines and Subs Capacity	Pasadena Working Space	1,010	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Genesee Co.
27	HVD Lines and Subs Capacity	Saginaw River Bank Replacement	36	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Saginaw Co.
28	HVD Lines and Subs Capacity	Silicon Sub - Replace -75 Switches	600	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Saginaw Co.
29	HVD Lines and Subs Capacity	WD0286 VERONA WORKING SPACE *02	1,550	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Calhoun Co.
30	HVD Lines and Subs Capacity	Delhi Varmaster Replacement	240	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Ingham Co.
31	HVD Lines and Subs Capacity	WD1078 ST LOUIS REPL 5690 & REM 5677 *05	230	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Isabella Co.
32	HVD Lines and Subs Capacity	WD1108 WILLIAMS - REPL CAP BANK *05	210	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Allegan Co.
33	HVD Lines and Subs Capacity	Gaylord Working Space	567	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Otsego Co.
34	HVD Lines and Subs Capacity	New 46kV Spur from Whitehall line to North Muskegon sub (Getty Line Removal)	1,960	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Muskegon Co.
35	HVD Lines and Subs Capacity	Phillips Working Space	628	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Kalamazoo Co.
36	HVD Lines and Subs Capacity	WD1213 EUREKA SUB WORKING SPACE *02	1,220	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Montcalm Co.
37	HVD Lines and Subs Capacity	WD0980 SPAULDING WORKING SPACE*05	351	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Kent Co.
38	HVD Lines and Subs Capacity	LN71X PARKWAY REPL 6444 6432 MOAB *13	360	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Kalamazoo Co.
39	HVD Lines and Subs Capacity	LN112G RIVERDALE INST LSEN, MOAB 5919*05	150	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Gratiot Co.
40	HVD Lines and Subs Capacity	Baker 138/46 kV Substation (Crandall)	1,160	1	Project(s)	. Load carrying capabilities and voltage support	Avoid Overloads/offset transmission investment, cust-min saved	**703,507**	Van Buren Co.
41	HVD Lines and Subs Capacity	LN049C LARKIN REBUILD 3.1 MILES % *05	184	1	Project(s)	. Load carrying capabilities and voltage support	Mitigate Inadequate Clearance, increase capacity / cust-min saved	**59,000**	Midland Co.
42	HVD Lines and Subs Capacity	LN111A SARANAC RBLD 4.5 MI 46 kV % *07	3,752	1	Project(s)	. Load carrying capabilities and voltage support	Mitigate Inadequate Clearance, increase capacity	**N/A**	Ionia Co.
43	HVD Lines and Subs Capacity	LN044W LINDEN REBUILD 3.91 MILES % *05	5,100	1	Project(s)	. Load carrying capabilities and voltage support	Avoid Overloads/Increase Capacity	**N/A**	Genesee Co.
44	HVD Lines and Subs Capacity	LN119A/119W/119AD Hammond Rd R/W 8.05MI	2,667	0	n/a	. ROW procurement	Procure Right of Way needed to support projects	N/A	Grand Traverse Co.
45	HVD Lines and Subs Capacity	LN019W MECOSTA RBLD 1.3 MI 46 kV R/W	300	0	n/a	. ROW procurement	Procure Right of Way needed to support projects	N/A	Mecosta Co.
46	HVD Lines and Subs Capacity	LN032F UNION ST 46KV LINE R/W	1,500	0	n/a	. ROW procurement	Procure Right of Way needed to support projects	N/A	Grand Traverse Co.
47	HVD Lines and Subs Capacity	LN033QQ SHEPHERD RP STR 452-456 *13	190	0	n/a	. ROW procurement	Procure Right of Way needed to support projects	N/A	Isabella Co.
48	HVD Lines and Subs Capacity	LN081K LAMOREAUX 46KV R/W ACQ TREE RIGHT	751	0	n/a	. ROW procurement	Procure Right of Way needed to support projects	N/A	Kent Co.
49	HVD Lines and Subs Capacity	LN105R ALDRICH 46 KV R/W 2.5 MI	718	0	n/a	. ROW procurement	Procure Right of Way needed to support projects	N/A	Genesee Co.
50	HVD Lines and Subs Capacity	New 46kV Spur from Whitehall line to North Muskegon sub R/W	2,000	0	n/a	. ROW procurement	Procure Right of Way needed to support projects	N/A	Muskegon Co.
51	HVD Lines and Subs Capacity	Walker R/W	231	0	n/a	. ROW procurement	Procure Right of Way needed to support projects	N/A	Kent Co.
51		**HVD Lines and Substations Capacity Total**	**41,904**						

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	Capacity								
1	LVD Subs Capacity	BELVEDERE	136	0	Project	New Substations	Obligation To Serve - Customers Impacted	-	Allegan
2		CRANDALL	959	0	Project	New Substations	Obligation To Serve - Customers Impacted	-	Van Buren
3		ERASTUS	3,075	1	Project	New Substations	Obligation To Serve - Customers Impacted	1,829	Isabella
4		GARMAN FOSTER	835	0	Project	New Substations	Obligation To Serve - Customers Impacted	-	St Joseph
5		MERCURY	220	0	Project	New Substations	Obligation To Serve - Customers Impacted	142	Calhoun
6		N AVE	238	0	Project	New Substations	Obligation To Serve - Customers Impacted	-	Kalamazoo
7		OSTERHOUT	127	0	Project	New Substations	Obligation To Serve - Customers Impacted	-	Kalamazoo
8		QUICKSILVER	2,614	0	Project	New Substations	Obligation To Serve - Customers Impacted	-	Kent
9		VALENTINE	1,814	0	Project	New Substations	Obligation To Serve - Customers Impacted	-	Kalamazoo
10		BILLWOOD	1,434	1	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	969	Eaton
11		BOYNE CITY	225	1	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	2,948	Charlevoix
12		CUTLERVILLE	113	1	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	1,075	Kent
13		EAST JACKSON	3,928	1	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	2,091	Jackson
14		GLEN LAKE	75	0	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	-	Leelanau
15		HARRISON	255	0	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	-	Clare
16		HICKORY	580	0	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	-	Muskegon
17		MARKEY	500	0	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	4,633	Roscommon
18		NEWARK	701	0	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	-	Oakland
19		NUNICA	624	0	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	-	Ottawa
20		TREMAINE	432	1	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	625	Ionia
21		**LVD Substations Capacity Total**	**18,885**	**6**					

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1	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in southern Michigan	(295)	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	southern Michigan
2	HVD Strategic Customers New Business	New 46 kV dedicated customer Substation in west Michigan	663	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	west Michigan
3	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in east Michigan	6,935	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	east Michigan
4	HVD Strategic Customers New Business	Two (2) new 138 kV dedicated customer Substations in west Michigan	11,280	2	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	west Michigan
5	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in west Michigan	1,178	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	west Michigan
6	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in east Michigan	631	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	east Michigan
7	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in northwest Michigan	3,950	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	northwest Michigan
8	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in east Michigan	16,546	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	east Michigan
9	HVD Strategic Customers New Business	Capacity increase at existing 138 kV dedicated customer Substation in west Michigan	2,117	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	west Michigan
		HVD Strategic Customers New Business Total	**43,005**					

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	New Business								
1	Metro New Business	VAN ANDEL ARENA ALLEY SVC	33	1	Project	Metro New Business	Grand Rapids	Secondary Service; Estimated Added Load; kVA	3
2		MT VERNON SOCCER ELEC	1000	1	Project	Metro New Business	Grand Rapids	Primary Service; Estimated Added Load; kVA	2,000
3		111 LYON PRIMARY	160	1	Project	Metro New Business	Grand Rapids	Primary Service; Estimated Load After Renovation; kVA	600
4		COREWELL RESIDENCE ELEC	150	1	Project	Metro New Business	Grand Rapids	Secondary Service; Estimated Added Load; kVA	500
5		300 MONROE	150	1	Project	Metro New Business	Grand Rapids	Primary Service; Estimated Load After Renovation; kVA	725
6		GVSU BLUE DOT ELEC	550	1	Project	Metro New Business	Grand Rapids	Primary Service; Estimated Load After Renovation; kVA	850
7		POCKET PARK ELEC	100	1	Project	Metro New Business	Grand Rapids	Secondary Service; Estimated Added Load; kVA	100
8		AMPITHEATER RESIDENTIAL TOWER CIVIL	2,000	1	Project	Metro New Business	Grand Rapids	Secondary Service; Estimated Added Load; kVA	-
9		EVENT CENTER PH3 CIVIL	500	1	Project	Metro New Business	Kalamazoo	Primary Service; Estimated Added Load; kVA	-
10		EVENT CENTER ELEC	750	1	Project	Metro New Business	Kalamazoo	Primary Service; Estimated Added Load; kVA	4,000
11		PARKING GARAGE ELEC	950	1	Project	Metro New Business	Kalamazoo	Secondary Service; Estimated Added Load; kVA	300
12		PARKING GARAGE PRI SVC	100	1	Project	Metro New Business	Kalamazoo	Primary Service; Estimated Added Load; kVA	1,000
13		315 W MICHIGAN AVE SVC	280	1	Project	Metro New Business	Kalamazoo	Secondary Service; Estimated Added Load; kVA	250
14		440 N CHURCH ST CIVIL	750	1	Project	Metro New Business	Kalamazoo	Secondary Service; Estimated Added Load; kVA	-
15		440 N CHURCH ST ELEC	300	1	Project	Metro New Business	Kalamazoo	Secondary Service; Estimated Added Load; kVA	500
16		MARIAN HALL ELEC	150	1	Project	Metro New Business	Flint	Secondary Service; Estimated Added Load; kVA	450
17		MASONIC SERV CIVIL	150	1	Project	Metro New Business	Flint	Secondary Service; Estimated Added Load; kVA	-
18		MASONIC SERV ELEC	150	1	Project	Metro New Business	Flint	Secondary Service; Estimated Added Load; kVA	300
19		832 WATER ST ELEC	150	1	Project	Metro New Business	Saginaw	Secondary Service; Estimated Added Load; kVA	300
20		99 W MICHIGAN ELEC	150	1	Project	Metro New Business	Battle Creek	Secondary Service; Estimated Added Load; kVA	300
21		225 MLK EV CHARGERS	100	1	Project	Metro New Business	Jackson	Secondary Service; Estimated Added Load; kVA	675
22		HAYES HOTEL CIVIL	400	1	Project	Metro New Business	Jackson	Secondary Service; Estimated Added Load; kVA	-
23		HAYES HOTEL ELEC	200	1	Project	Metro New Business	Jackson	Secondary Service; Estimated Added Load; kVA	1,200
24		**Metro New Business Total**	**9,223**						

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	Asset Relocations								
1	Metro Relocations	CHERRY ST; LAGRAVE TO LAFAYETTE CIVIL	2,000	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	43
2		FRONT TO PEARL CIVIL	2,400	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	3
3		WEALTHY ST (QUICKSILVER) CIVIL	3,500	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	492
4		ANN ST TRAIL CIVIL$	-	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted; reimbursible	11
5		ANN ST TRAIL ELEC$	-	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted; reimbursible	11
6		WATSON CKT DOUGLAS RISER	50	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted;	127
7		INGHAM SUB Δ TO WYE CONVERSION	1,200	1	Project	Metro Relocations	Jackson	Substation Coordination; customer impacted	149
8		SAGINAW MEDICAL DIAMOND PH 1 ELEC $	-	1	Project	Metro Relocations	Saginaw	Coordination of Utilties; customers impacted; reimbursible	11
9		SAGINAW MEDICAL DIAMOND PH 2 ELEC	1,000	1	Project	Metro Relocations	Saginaw	Coordination of Utilties; customers impacted	11
10		SAGINAW MEDICAL DIAMOND PH 3 ELEC	1,000	1	Project	Metro Relocations	Saginaw	Coordination of Utilties; customers impacted	11
11		KALAMAZOO AVE CIVIL	7,000	1	Project	Metro Relocations	Kalamazoo	Coordination of Utilties; customers impacted	21
12		KALAMAZOO AVE PRI RELOC	3,000	1	Project	Metro Relocations	Kalamazoo	Coordination of Utilties; customers impacted	768
13		PARK ST OH TO UG	51	1	Project	Metro Relocations	Kalamazoo	Coordination of Utilities; customers impacted	14
14		ALDRICH DUCT MDOT M-21 REBUILD CIVIL	5,000	1	Project	Metro Relocations	Flint	Coordination of Utilities; customers impacted	
15		**Metro Relocations Total**	**26,201**						

MICHIGAN PUBLIC SERVICE COMMISSION
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2027-2028 Test Year LVD Project List
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Test)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Lines Reliability	Casino	5,514	8.5	Miles	Line Rebuilds	Customer*Minutes Avoided	293,792	Isabella County
2		Remus	4,320	8.0	Miles	Line Rebuilds	Customer*Minutes Avoided	93,352	Montcalm and Mecosta Counties
3		Goodale	130	0.2	Miles	Line Rebuilds	Customer*Minutes Avoided	9,575	Battle Creek
4		Port Sheldon	324	0.5	Miles	Line Rebuilds	Customer*Minutes Avoided	3	Ottawa County
5		Broadway	389	0.6	Miles	Line Rebuilds	Customer*Minutes Avoided	6,509	Muskegon
6		Roberts	2,168	0.3	Miles	Line Rebuilds	Customer*Minutes Avoided	1,231	Jackson
7		Parnall	482	0.3	Miles	Line Rebuilds	Customer*Minutes Avoided	2,046	Jackson
8		Westwood	277	1.3	Miles	Line Rebuilds	Customer*Minutes Avoided	73,486	Jackson
9		Oat St	8,855	1.5	Miles	Line Rebuilds	Customer*Minutes Avoided	78,001	Jackson
10		Parma	2,087	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	2,397	Jackson
11		Stockbridge	2,183	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	929	Jackson
12		Leslie	1,714	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	2,160	Jackson
13		Parnall 2	1,760	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	2,813	Jackson
14		Hanover	815	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	1,733	Jackson
15		Westwood 2	837	0.1	Miles	Line Rebuilds	Customer*Minutes Avoided	2,179	Jackson
16		Westwood 3	14	0.0	Miles	Line Rebuilds	Customer*Minutes Avoided	-	Jackson
17		Lake Shore	2,096	0.8	Miles	Line Rebuilds	Customer*Minutes Avoided	6,284	Grand Haven
18		Newaygo	391	0.3	Miles	Line Rebuilds	Customer*Minutes Avoided	5,830	Newaygo
19		Dontz	1,171	1.3	Miles	Line Rebuilds	Customer*Minutes Avoided	3,886	Manistee
20		Goodale 2	1,881	2.9	Miles	Line Rebuilds	Customer*Minutes Avoided	76,361	Battle Creek
21		Mt. Pleasant	2,465	3.8	Miles	Line Rebuilds	Customer*Minutes Avoided	187,082	Mt. Pleasant
22		Saranac	1,492	2.3	Miles	Line Rebuilds	Customer*Minutes Avoided	27,531	Ionia County
23		**Line Rebuilds Total**	**41,365**	33.2				**877,178**	
24		Homestead	2,117	22.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	601,493	Manistee and Benzie Counties
25		Grand Ledge	849	9.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	-	Clinton County
26		Grand Blanc	345	3.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	115,967	Genesee County
27		Grand Blanc 2	345	3.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	115,967	Genesee County
28		Grand Blanc 3	196	2.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	131,639	Genesee County
29		Davison - Dort	756	8.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	768,004	Genesee County
30		Shattuck	224	2.4	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	158,011	Saginaw County
31		Auburn	233	2.5	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	45,167	Bay County
32		Auburn 2	56	0.6	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	10,840	Bay County
33		Auburn 3	224	2.4	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	43,360	Bay County
34		Manchester	410	4.4	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	199,672	Jackson County
35		Manchester 2	75	0.8	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	36,304	Jackson County
36		Manchester 3	84	0.9	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	40,842	Jackson County
37		Oriole	233	2.5	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	70,288	Ludington
38		Morrice	177	1.9	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	97,220	Clinton County
39		Lincoln	280	3.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	152,501	Alcona County
40		New Richmond	298	3.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	129,892	Allegan County
41		New Richmond 2	47	0.5	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	20,296	Allegan County
42		Ranger Lake	205	2.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	85,004	Iosco County
43		North Kent	19	0.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	9,518	Kent County
44		Lamoreaux	93	1.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	82,315	Kent County
45		Mendon	485	5.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	73,281	Kalamazoo County
46		Mendon 2	298	3.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	90,192	Kalamazoo County
47		Mendon 3	47	0.5	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	14,093	Kalamazoo County
48		Mendon 4	84	0.9	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	25,367	Kalamazoo County
49		Beers	345	3.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	104,405	Genesee County
50		Henry	65	0.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	9,230	Bay City
51		Henry 2	131	1.4	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	18,459	Bay City
52		Hammond	84	0.9	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	15,629	Grand Traverse County
53		Twin Lake	112	1.2	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	14,562	Muskegon County
54		Shepherd	103	1.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	23,287	Isabella County
55		Manistee	103	1.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	3,537	Manistee County
56		Manistee 2	103	1.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	7,073	Manistee County
57		Manistee 3	345	3.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	23,791	Manistee County
58		Chrysler	354	3.8	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	4,617	Washtenaw County
59		Alabaster	65	0.7	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	15,925	Iosco County
60		Rogers	261	2.8	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	29,876	Newaygo County
61		Virginia Park	606	6.5	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	144,758	Allegan County
62		Howard City	187	2.0	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	46,760	Montcalm County
63		Ionia #2	588	6.3	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	65,552	Ionia County
64		Gerrish	597	6.4	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	105,712	Crawford County
65		Thomas	616	6.6	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	42,455	Saginaw County
66		Scottville	168	1.8	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	9,617	Mason County
67		Saranac	290	3.1	Miles	Pole Top Rehabilitation	Customer*Minutes Avoided	37,107	Ionia County
68		**Pole Top Rehabilitation Total**	**13,303**	**142.6**	Miles			**3,839,582**	
69		Pole Replacements	**25,753**	1040	Poles	Pole Replacements	Customer*Minutes Avoided	**1,343,672**	Various locations statewide
70		Switch Replacements	**12,661**	97	Switches	Switch Replacements	Customer*Minutes Avoided	**92,138**	Various locations statewide
71		Pole Top Assembly Replacement	**4,990**	583	PTAs	Pole Top Assembly Replacements	Customer*Minutes Avoided	**746,058**	Various locations statewide
72		Line Sensors	**2,374**	208	Sensor Locations	Line Sensor Deployment	Improve reliability through increased outage detection		Various locations statewide
73		Real Estate	**8,332**			Right of Way Acquisition	Procure Right of Way needed to support projects		Various locations statewide
74		**HVD Lines Reliability Total**	**108,778**					**6,898,627**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2027-2028 Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-157 (KKL-4)
Page: 2 of 14
Witness: KKLaFrance
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Test)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Substation Reliability	WD0785 Delaney Reliability Improvement	851	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,674	Genesee
2		WD0951 Looking Glass Replace 4 Breakers	1930	4	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	10,697	Ingham
3		WD1108 Williams - Repl 156 Varmaster VSW	463	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Maintain System Voltage		Allegan
4		WD0064 Beecher Reliability Improvement	3516	6	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	16,046	Lenawee
5		WD1211 Bard Road Replace 156 Varmaster VSW	675	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Maintain System Voltage		Gladwin
6		WD0562 Engine Plant Replace 3 Gas Breakers	1256	3	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	8,023	Genesee
7		WD1169 Mecosta Repl 156 VSW	527	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Maintain System Voltage		Mecosta
8		WD0070 Water Street Replace 5 Breakers	2000	5	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	13,371	Bay
9		WD1085 Amber Replace 7 Breakers	2100	7	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	18,720	Mason
10		WD1160 Vevay Replace 156 Varmaster VSW	675	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Maintain System Voltage		Ingham
11		WD0235 Beals Rd Replace 600 Gas Breaker	500	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,674	Kent
12		WD0152 Cement City Repl 156 VSW	584	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Maintain System Voltage		Jackson
13		WD1108 Williams Replace 3 Breakers	1455	2	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	5,349	Allegan
14		WD1160 Vevay Replace 3 Breakers	1445	0	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	-	Ingham
15		WD0823 Diesel Tech Replace 199 (138kV)	500	1	Equipment	Circuit Breaker and Circuit Switcher Replacements	Customer*Minutes Avoided	2,674	Kent
16		WD1243 Amway Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Kent
17		WD1448 Port Sheldon Yard/Drive Improvement	252	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Ottawa
18		WD0235 Beals Animal Mit, Security Improvement, Fence Replacements	991	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Kent
19		WD1117 Lawndale Install Drone	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Saginaw
20		WD1179 Skylark Install Drone	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Genesee
21		WD0085 Elm Street Install Drone	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Calhoun
22		WD1120 Hogsback Install Drone	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Ingham
23		WD0235 Beals Road Install Drone	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Kent
24		WD0738 Pipe Line Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Bay
25		WD0967 Mcnally Install Mobile Pad	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Charlevoix
26		WD0021 Rogers Hydro, Security Improvement, Fence Replacement	168	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Mecosta
27		WD1167 West Shore Yard Improvements (Fence, Stone, Gate)	212	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Mason
28		WD0095 Croton, Security Improvement, Fence Replacement, Lighting	302	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Newaygo
29		WD0979 Halsey, Security Improvement, Fence Replacement	480	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Oakland
30		WD1220 Bass Creek, Security Improvement, Fence Replacement	512	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Ottawa
31		WD0730 Warren Replace Cap Fences	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Midland
32		WD0730 Warren Replace Perimeter Fence	578	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Midland
33		WD0837 Briggs & Straton Animal Mit, Security Improvement, Fence Replace	75	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Muskegon
34		WD0837 Briggs & Stratton Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Muskegon
35		WD0046 Bullock Replace Cap Fence	80	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Midland
36		WD0046 Bullock Replace Perimeter Fence	589	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Midland
37		WD2157 CLYDE GEN REPL RTU AND COMM	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Kent
38		WD1368 BROADMOOR REPL RTU & COMMS	250	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Kent
39		WD0799 Sealed Power Install Mobile Pad	180	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Muskegon
40		WD1213 EUREKA REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Montcalm
41		WD1533 HILE RD REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Muskegon
42		WD1100 LINDBERGH REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Kalamazoo
43		WD0525 RIGGSVILLE REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Cheboygan
44		WD0718 Blair Road Replace Gate	40	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Substation Security		Iosco
45		WD0111 Dome Pipe Line Replace Fence	98	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Monroe
46		WD0053 Lenawee Stamping Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Lenawee
47		WD1445 Big Chief Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Bay
48		WD0980 Spaulding Replace Obsolete #1 & #2 Cap Bank Controllers	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Kent
49		WD0507 Detroit Gasket 46Kv MOAB Scada	30	2	Equipment	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Ionia
50		WD0975 Almeda Replace Fence	360	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Bay
51		WD0021 ROGERS HYD REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Mecosta
52		WD0001 ALMA REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Gratiot
53		WD1071 Lockwood Fence, Stone, Drive	50	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Saginaw
54		WD0111 Dome Pipe Line New Mobile Pad	98	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Monroe
55		WD0975 ALMEDA REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Bay
56		WD0640 MARQUETTE REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Ionia
57		WD0384 Jackson Rcf Install Mobile Pad	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Jackson
58		WD0980 SPAULDING REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Kent
59		WD0046 BULLOCK REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Midland
60		WD2064 GRAYLING CO REPL RTU AND COMMS	75	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Crawford
61		WD0085 ELM STREET REPL RTU AND COMMS	250	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Calhoun
62		WD0389 HAZELWOOD REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Allegan
63		WD0105 HEMPHILL REPL RTU AND COMMS	150	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Genesee
64		WD1180 Wolverine Install Mobile Pad And Replace Fence	200	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Calhoun
65		WD0266 ISLAND RD REPL RTU AND COMMS	90	0	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Eaton
66		WD2161 LARCH GEN REPL RTU AND COMMS	90	0	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Clare
67		WD0961 SEALPOC Repl Fence	80	0	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	-	Clinton
68		WD1182 PARR RD REPL RTU AND COMMS	50	0	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Washtenaw
69		WD0341 POTTER REPL RTU AND COMMS	50	0	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Replace Obsolete equipment		Saginaw
70		WD0752 Stronach Laser Bird Mitigation	100	1	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided	47,034	Manistee
71		Blanket Mobile Pads	500	5	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Various
72		Blanket For Cap Bank Controlers	1000	10	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	System Operability		Various
73		Blanket Yard Improvement/Fence Replacement/Animal Mit (Hvd Or Sec)	3900	10	Projects	HVD Subs Other Equipment and Animal Mitigation Projects	Customer*Minutes Avoided		Various
74		WD0398 Swartz Creek Repl SW & Arresters	83	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	2,048	Genesee
75		WD1169 Mecosta Replace TB#1 SOGS	60	1	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	2,048	Mecosta
76		WD0007 Muskegon Heights Replace Obsolete Switches	280	8	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	16,380	Muskegon
77		WD0208 Pasadena Replace Obsolete Switches	320	6	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	12,285	Genesee
78		WD0560 Riverview Replace Obsolete Switches	400	7	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	14,333	Kalamazoo
79		WD0768 Silicon Replace Obsolete Switches	420	11	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	22,523	Saginaw
80		WD0100 Wealthy Street Replace Obsolete Switches	460	11	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	22,523	Kent
81		WD0605 Wexford Replace Obsolete Switches	460	11	Equipment	HVD Switch Replacements	Customer*Minutes Avoided	22,523	Wexford
82		WD0095 Croton Control House Improvement	200	1	Projects	Replacement of substation equipment imminent failures	System Operability		Newaygo
83		WD1250 Ransom Replace Battery	89	1	Projects	Replacement of substation equipment imminent failures	System Operability		Ottawa
84		WD0166 Solvay Repl Station Battery	75	1	Projects	Replacement of substation equipment imminent failures	System Operability		Lenawee
85		WD0682 Cleveland Repl Battery, Rack & Charger	75	1	Projects	Replacement of substation equipment imminent failures	System Operability		Ottawa
86		WD1532 Pingree Replace Battery	80	1	Projects	Replacement of substation equipment imminent failures	System Operability		Ottawa
87		WD0623 Beaver Creek Repl Battery	85	1	Projects	Replacement of substation equipment imminent failures	System Operability		Crawford
88		WD0806 Eaton Rapids Municipal Repl Battery	100	1	Projects	Replacement of substation equipment imminent failures	System Operability		Eaton
89		WD1099 Raisin Repl Battery	400	1	Projects	Replacement of substation equipment imminent failures	System Operability		Lenawee
90		WD0131 Grey Iron TB3 & TB4 LTC Controllers	84	1	Equipment	Replacement of substation equipment imminent failures	System Operability		Saginaw
91		WD0785 Delaney Repl SPTs	130	2	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	9,600	Genesee
92		WD0360 Liberty Moloney Pt	65	1	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	4,800	Calhoun
93		WD0980 Spaulding Replace Moloney Pt	65	1	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	4,800	Kent
94		WD1448 Port Sheldon Replace Battery	80	1	Projects	Replacement of substation equipment imminent failures	System Operability		Ottawa
95		WD0999 Rickert Replace Battery	150	1	Projects	Replacement of substation equipment imminent failures	System Operability		Ionia
96		WD0209 Pasadena Replace Moloney SPT	65	1	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	4,800	Genesee
97		WD0737 Ravenna Replace 3Ph Regulator	650	1	Equipment	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	1	Muskegon
98		Emergent Equipment Replacements (Bushings, Arrestors, Switches)	1000	10	Projects	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	240,000	Various
99		SEC Regulators	1000	10	Projects	Replacement of substation equipment imminent failures	Customer*Minutes Avoided	10	Various
100		Station Batteries Identified During Testing	4000	20	Projects	Replacement of substation equipment imminent failures	System Operability		Various
101		WD1098 Pigeon Lake Repl O+C Bushings	140	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Ottawa
102		WD0090 Charlotte Replace HS Bushings	300	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Eaton
103		WD0228 Agnew - Repl O+C Bushings	167	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Ottawa
104		WD0573 Ohman Rd Repl O+C Bshngs	140	1	Projects	Transformer Bushing Replacements	Customer*Minutes Avoided	69,552	Osceola
105		Transformer Bushings TBD	1000	5	Projects	Transformer Bushing Replacements			
106		**HVD Substations Reliability Total**	**46,180**						

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For the Test Year 12 Months Ending April 30, 2028
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Case No.: U-22070
Exhibit No.: A-157 (KKL-4)
Page: 3 of 14
Witness: KKLaFrance
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Test)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	Transformer Bank Replacements and Substation Rebuilds	WD1800 ARMORY NEW 138/46KV SUB TB2	7350	0	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	78,624	Gratiot
2		WD1815 ROYAL NEW SUB	13435	0	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	78,624	Jackson
3		WD0053 LENAWEE STAMPING REBUILD	236	0	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	7	Lenawee
4		WD0443 DEARBORN MACHINE REBUILD	300	0	Projects	HVD Substation Rebuilds	Customer*Minutes Avoided	7	Muskegon
5		WD0354 ALMA PRODUCTS RPL TB1	200	1	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Gratiot
6		WD0191 CROTTY REPL TB3	291	1	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Bay
7		WD0670 STOVER REPL TB1	3176	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Antrim
8		WD0967 McNally repl TB #2	500	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Charlevoix
9		WD1073 OGEMAW REPL TB1	146	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Ogemaw
10		WD1214 GLEANER REPLACE TB NO.1	194	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Saginaw
11		WD1489 VERNON REPLACE TB NO.1	248	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Isabella
12		WD1180 WOLVERINE REPL TRANS	289	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Calhoun
13		WD0384 JACKSON RCF REPL TRANS	226	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Jackson
14		WD0095 CROTON REPL TRANS #3	581	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Newaygo
15		WD0660 MCGULPIN REPL TRANS #1 & #2	1162	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Emmet
16		WD0167 HSC REPL TRANS NO.3	581	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Saginaw
17		WD0161 ROCHESTER PROD REPL TRANS#2	283	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Ottawa
18		WD0738 PIPE LINE REPL TRANS #1	320	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Bay
19		WD1445 BIG CHIEF REPL TRANS #3	266	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Bay
20		WD0428 GUARDIAN REPL TRANS #2	258	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Calhoun
21		WD0428 GUARDIAN REPL TRANS #3	216	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Calhoun
22		WD1243 AMWAY REPL TRANS	255	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Kent
23		WD0926 ANN STREET REPL TRANS	303	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Kent
24		WD0159 BERMAN STEEL REPL TRANS	373	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Kent
25		WD0077 MARATHON REPL TRANS	226	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Monroe
26		WD0152 CEMENT CITY REPL TRANS	435	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Jackson
27		WD1170 SAMARIA TRANS TB2	435	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Monroe
28		WD0929 EXTRUDED METALS REPL TRANS	372	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Kent
29		WD1253 CADILLAC MALLEABLE REPL TRF #1	363	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Wexford
30		WD1450 UPJOHN RESEARCH REPL TRANS #2	495	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	1	Kalamazoo
31		WD0610 BINGHAM REPL TRANS #1	755	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Clinton
32		WD0956 DEJA REPL TRANS #1	435	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Montcalm
33		WD1085 AMBER REPL TRANS #1	630	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Mason
34		WD0892 MANLIUS REPL TRANS NO.2	435	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Allegan
35		WD0085 ELM STREET REPL TRANS #4	630	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Calhoun
36		WD0286 VERONA REPL TRANS #1	755	0	Equipment	HVD Substation Transformer Replacement Imminent Failure	Customer*Minutes Avoided	7,020	Calhoun
37		**Transformer Bank Replacements and Substation Rebuilds Total:**	**37,155**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
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($000)

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Benefit Type	(h) Benefit	(i) Location
	Reliability								
1	LVD Substations Reliability	ALCONA DAM	585	1	Project	Rebuild Substations	Reliability - outage minutes avoided	2,031,480	Alcona
2		ANGELL	2,820	1	Project	Rebuild Substations	Reliability - outage minutes avoided	498,960	Grand Traverse
3		GREENBUSH	560	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Alcona
4		GREENSPIRE	531	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Kalamazoo
5		MANTON	545	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Wexford
6		NORTH MUSKEGON	776	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Muskegon
7		OAK STREET	1,141	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Jackson
8		ONSTED	352	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Lenawee
9		PALO	2,958	1	Project	Rebuild Substations	Reliability - outage minutes avoided	1,062,720	Ionia
10		PEWAMO	585	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Clinton
11		PIERSON	338	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Montcalm
12		PULLMAN	545	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Allegan
13		ROUND LAKE	251	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Lenawee
14		THORNAPPLE	776	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Kent
15		TWIN LAKE	545	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Muskegon
16		WESTPHALIA	358	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Clinton
17		WITHEY LAKE	394	0	Project	Rebuild Substations	Reliability - outage minutes avoided	-	Ogemaw
18		MOBILE 26	1,854	0	Project	Mobile Substations	Reliability - outage minutes avoided	-	Statewide
19		MOBILE 28	2,252	0	Project	Mobile Substations	Reliability - outage minutes avoided	-	Statewide
20		MOBILE 29	2,252	0	Project	Mobile Substations	Reliability - outage minutes avoided	-	Statewide
21		ABBE	120	2	Regulators	Regulator Replacements	Service Quality; number of customers	766	Oscoda
22		BEECHER	540	9	Regulators	Regulator Replacements	Service Quality; number of customers	2,067	Lenawee
23		BENNETT	540	9	Regulators	Regulator Replacements	Service Quality; number of customers	3,468	Ingham
24		BLACKMAN	360	6	Regulators	Regulator Replacements	Service Quality; number of customers	886	Jackson
25		CHAUNCEY	120	2	Regulators	Regulator Replacements	Service Quality; number of customers	1,194	Calhoun
26		CHICAGO	180	3	Regulators	Regulator Replacements	Service Quality; number of customers	2,739	Ottawa
27		CLYDE ROAD	180	3	Regulators	Regulator Replacements	Service Quality; number of customers	1,083	Ionia
28		HOWARD CITY	180	3	Regulators	Regulator Replacements	Service Quality; number of customers	1,331	Montcalm
29		LAKE LANSING	180	3	Regulators	Regulator Replacements	Service Quality; number of customers	1,627	Ingham
30		MICHIGAN CENTER	180	3	Regulators	Regulator Replacements	Service Quality; number of customers	1,985	Jackson
31		MICOR	360	6	Regulators	Regulator Replacements	Service Quality; number of customers	660	Jackson
32		VANDERCOOK LAKE	540	9	Regulators	Regulator Replacements	Service Quality; number of customers	3,637	Jackson
33		ZYLMAN	120	2	Regulators	Regulator Replacements	Service Quality; number of customers	1	Kalamazoo
34		BROADMOOR TB3	2,091	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
35		BROADMOOR TB4	2,091	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
36		TUNNEL PARK	788	1	Project	Transformer Replacements	Reliability - outage minutes avoided	180	Ottawa
37		ALLENDALE PUMPING	339	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Ottawa
38		BAILEY	325	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Muskegon
39		BAYBERRY TB2	586	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
40		EAST GRANT	325	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Newaygo
41		FOREST GROVE TB2	776	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Ottawa
42		FRANKFORT TB1	332	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Benzie
43		FRANKFORT TB2	221	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Benzie
44		FROST	325	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Clare
45		FULTON	578	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
46		HOPKINS	307	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Allegan
47		KELLOGGSVILLE TB1	578	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
48		KELLOGGSVILLE TB2	578	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
49		KENDALL	349	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kalamazoo
50		LAKE SHORE	210	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Ottawa
51		LEE STREET	776	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
52		MAYFAIR	349	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Genesee
53		MORRELL	608	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Jackson
54		MUSKEGON HEIGHTS TB5	776	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Muskegon
55		MUSKEGON HEIGHTS TB6	776	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Muskegon
56		MUSKEGON TREATMENT TB1	339	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Muskegon
57		MUSKEGON TREATMENT TB2	339	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Muskegon
58		NORTH KENT TB1	349	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
59		NORTH KENT TB3	353	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kent
60		READING	326	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Hillsdale
61		RED CEDAR	406	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Ingham
62		RICHLAND	307	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kalamazoo
63		SHERIDAN	307	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Montcalm
64		TRAVIS	545	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Kalamazoo
65		WALNUT	416	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Genesee
66		WILLIAMS TB1	545	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Allegan
67		WILLIAMS TB2	545	0	Project	Transformer Replacements	Reliability - outage minutes avoided	-	Allegan
68		**LVD Substations Reliability Subtotal**	**42,880**	**64**					

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Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Benefit Type	(h) Benefit	(i) Location
	Reliability								
1	LVD Substations Rehabilitation	BALLENGER	885	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Genesee
2		FRASER PUMPING	646	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Bay
3		GLADWIN	908	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Gladwin
4		GMI	920	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Genesee
5		GODFREY	337	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	1,258,200	Kent
6		GOLDEN	951	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Midland
7		HART	846	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Oceana
8		INTERLOCHEN	900	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Grand Traverse
9		IONIA MANUFACTURING	589	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Ionia
10		JUNCTION PUMPING	463	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Bay
11		LEITH STREET	2,700	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	735,120	Genesee
12		LENNON ROAD	1,870	1	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	409,320	Genesee
13		LYONS	265	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Ionia
14		MAYFAIR	951	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Genesee
15		NESTROM	924	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Muskegon
16		SAGINAW STREET	1,215	0	Project	Allis Chalmers Substation Transformers	Reliability - outage minutes avoided	-	Genesee
17		BLUE WATER	413	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	567,900	Clinton
18		FAIRBANKS	1,345	0	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	-	Kent
19		GODFREY	448	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	143,520	Kent
20		HOWARD CITY	113	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	239,580	Montcalm
21		KENDRICK	1,516	1	Project	Equipment Replacement and Regulatory	Regulatory Compliance	-	Kent
22		MANCELONA	300	1	Project	Equipment Replacement and Regulatory	Reliability - outage minutes avoided	2,044,440	Antrim
23		MEADOWBROOKE	675	1	Project	Equipment Replacement and Regulatory	Regulatory Compliance	-	Kent
24		ALPINE	150	5	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	237,420	Kent
25		APPLETON	150	5	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	470,340	Mecosta
26		ASHMAN CIRCLE	150	7	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	760,680	Midland
27		BEALS ROAD	150	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	1,491,120	Kent
28		BENNETT	150	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	624,240	Ingham
29		BLACKMAN	300	12	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	820,620	Jackson
30		BROADWAY	150	5	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	532,620	Muskegon
31		BULLOCK	150	5	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	453,960	Midland
32		BURROWS	150	3	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	730,980	Saginaw
33		CALVIN	300	10	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	1,004,220	Kent
34		CHEYENNE	300	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	1,177,740	Saginaw
35		CHICAGO	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	848,340	Ottawa
36		CORUNNA	150	5	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	322,200	Shiawassee
37		FOUR MILE	200	4	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	858,600	Kent
38		FOURTEENTH STREET	200	8	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	978,120	Genesee
39		GRANDVILLE	200	8	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	996,840	Kent
40		HARING	200	4	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	144,900	Wexford
41		HASKELITE	300	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	808,200	Kent
42		HOWARD CITY	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	613,620	Montcalm
43		ISABELLA	200	4	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	669,960	Isabella
44		LAKE LANSING	150	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	895,860	Ingham
45		LEFFINGWELL	250	13	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	622,260	Kent
46		LESLIE INDUSTRIAL	100	2	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	32,040	Ingham
47		MCGRAW	300	2	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	244,440	Bay
48		MICHIGAN CENTER	450	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	498,240	Jackson
49		MICOR	150	3	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	118,800	Jackson
50		OSCODA	100	4	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	453,600	Iosco
51		**LVD Substations Rehabilitation Subtotal**	**25,430**					**22,808,040**	

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	Reliability								
1	LVD Substations Rehabilitation	PARKWAY	200	4	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	556,740	Kalamazoo
2		PHILLIPS	250	5	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	998,640	Kalamazoo
3		RAMONA	150	3	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	763,200	Kent
4		SOUTH WASHINGTON	200	4	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	216,000	Saginaw
5		STONEGATE	300	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	803,880	Kent
6		SWARTZ CREEK	150	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	714,060	Genesee
7		VANDERCOOK LAKE	150	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	654,660	Jackson
8		ZYLMAN	100	4	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	253,800	Kalamazoo
9		ABBE	150	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	535,140	Oscoda
10		BEECHER	150	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	424,440	Lenawee
11		BLUE WATER	510	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	567,900	Clinton
12		CHAUNCEY	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	435,420	Calhoun
13		CLYDE ROAD	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	399,060	Ionia
14		HARLEM	150	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	240,840	Ottawa
15		HARRISON	200	12	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	946,440	Clare
16		HOLTON	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	668,160	Muskegon
17		HOMER	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	320,580	Calhoun
18		HUNT ROAD	200	12	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	569,700	Lenawee
19		JACKMAN	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	585,000	Monroe
20		M.A.E.	100	2	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	394,020	Monroe
21		MACKINAW CITY	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	230,220	Cheboygan
22		MARKER LAKE	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	226,980	Ionia
23		MAUMEE	100	2	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	567,900	Lenawee
24		MCCRACKEN	250	5	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	690,660	Muskegon
25		NAPOLEON	200	12	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	586,980	Jackson
26		NOBLE	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	401,400	Arenac
27		NORTH PARK	150	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	756,000	Kent
28		OLIVER	150	3	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	327,960	Shiawassee
29		PARNALL	200	8	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	580,140	Jackson
30		PIGEON LAKE	100	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	421,740	Ottawa
31		RAVINE	100	2	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	515,160	Kalamazoo
32		SAUGATUCK	150	9	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	875,880	Allegan
33		SUMMIT	150	3	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	667,080	Jackson
34		SYLVAN	188	6	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	295,380	Washtenaw
35		UNIVERSITY	100	2	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	97,380	Ingham
36		WILDWOOD	150	3	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	509,580	Jackson
37		WISNER	150	5	Reclosers	Recloser Replacements	Reliability - outage minutes avoided	244,800	Jackson
38		**LVD Substations Rehabilitation Subtotal**	**5,898**					**19,042,920**	
39		**LVD Substations Rehabilitation Total**	**31,328**					**41,850,960**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
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($000)

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Metro Reliability	MECHANIC VAULT DF	525	1	Project	Deadfronting	Jackson	Worker Safety	-
2		EDWARDS VAULT DF	300	1	Project	Deadfronting	Kalamazoo	Worker Safety	-
3		ACADEMY & CHURCH ST CIVIL	1,800	1	Project	Obsolete or Needed Civil	Kalamazoo	Customer-outage-minutes avoided	-
4		ACADEMY & CHURCH ST ELEC	196	1	Project	Obsolete or Needed Electrical	Kalamazoo	Customer-outage-minutes avoided	1,320
5		MT VERNON; FULTON TO PEARL ST CIVIL	1,000	1	Project	Obsolete or Needed Civil	Grand Rapids	Customer-outage-minutes avoided	695
6		MT VERNON; FULTON TO PEARL ST ELEC	310	1	Project	Obsolete or Needed Electrical	Grand Rapids	Customer-outage-minutes avoided	695
7		**Metro Reliability Total**	**4,131**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Metro Rehabilitation	CORTLAND MECHANIC TO JACKSON CIVIL PH 2	1,500	1	Project	Vault or Manhole Rehabilitation	Jackson	Customer-outage-minutes avoided	-
2		CORTLAND MECHANIC TO JACKSON ELEC PH 2	1,000	1	Project	Vault or Manhole Rehabilitation	Jackson	Customer-outage-minutes avoided	9,011
3		WASHINGTON AVE CIVIL PH 1	2,995	1	Project	Crushed Duct	Saginaw	Customer-outage-minutes avoided	-
4		**Metro Rehabilitation Total**	**5,495**						

MICHIGAN PUBLIC SERVICE COMMISSION
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	(a)	(b)	(c)	(d)	(e)	(f)		
Line No.	**Sub-Program**	**Project Description, Line, Substation, or Location**	**Projected Period Spending (Test)**	**Units**	**Unit Type**	**Investment Category**	**Benefit Type**	**Location**
1	System Protection	OWOSSO	592	4	Relay Packages	Line Exit Relay Replacements	Safety	Owosso
2		DOWLING	230	1	Relay Packages	Line Exit Relay Replacements	Safety	Hudson
3		WATER STREET	1,700	7	Relay Packages	Line Exit Relay Replacements	Safety	Bay City
4		COLE CREEK	250	1	Relay Packages	Line Exit Relay Replacements	Safety	Flushing
5		MILES RD	320	3	Relay Packages	Line Exit Relay Replacements	Safety	East Jordan
6		BEAVER CREEK	580	4	Relay Packages	Line Exit Relay Replacements	Safety	Grayling
7		RIVERVIEW	800	6	Relay Packages	Line Exit Relay Replacements	Safety	Kalamazoo
8		BEECHER	200	2	Relay Packages	Line Exit Relay Replacements	Safety	Adrian
9		**System Protection Total:**	**4,672**					

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Test)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Benefit	Location
1	HVD Lines and Subs Capacity	WD0285 Claremont INST CKTSWR	1,250	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Saginaw Co.
2		Cobb Substation - New METC Chopin Station Coordination	1,610	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Muskegon Co.
3		LN100AB BENSTON SPUR 1.8 MI 138kV LN *08 (associated with Cobb-Dupont-White Lake Rebuild)	2,395	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Muskegon Co.
4		METC's Iosco - Karn Rebuild (CE work at Santiago tap, Seven Mile tap, and Cottage Grove)	4,163	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Arenac/Bay Co.
5		Port Sheldon Substation - Replace 199 MOABS-SOGS with 138 kV Circuit Switcher and Relay Installation (METC)	1,205	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Ottawa Co.
6		WD0730 WARREN INST CKT SWR METC RLY *05	610	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Midland Co.
7		Wealthy Street Substation - New METC Snowy Station Coordination	5,135	1	Project(s)	. Coordination with Transmission	Meet Contractual Requirements	N/A	Kent Co.
8		COLE CREEK Replace SOGS/MOABS with Circuit Switcher	500	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Genesee Co.
9		Delaney Working Space	3,360	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Genesee Co.
10		Dowling Sub - Replace 199 with CSW	540	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Lenawee Co.
11		GLEANER BUS RECONFIGURATION	2,000	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Saginaw Co.
12		Grand Blanc BOC - Reconfigure Substation feed for METC	813	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Genesee Co.
13		OWOSSO Replace SOGS/MOABS with Circuit Switcher	500	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Shiawassee Co.
14		Pasadena Working Space	35	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Genesee Co.
15		Saginaw River Bank Replacement	2,900	1	Project(s)	. Improved functionality	Replace to Standard location/increase capacity/reliability	N/A	Saginaw Co.
16		LN042V EATON RAPIDS 46KV INST MOABS *13	372	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Eaton Co.
17		GRAPHITE SUB SWITCH INSTALLS	600	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Saginaw Co.
18		WILLARD Replace SOGS/MOABS with Circuit Switcher	500	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Saginaw Co.
19		SALT STREET SUB - INSTALL MOAB on line after sub removal.	500	1	Project(s)	. Improved functionality	Safety/New Standards, cust-min saved	429,970	Saginaw Co.
20		Oakland Sub - Equipment ugrades for METC relay coordination	1,719	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Oakland Co.
21		Beecher Sub - Install additional relaying for METC	1,220	1	Project(s)	. Improved functionality	Safety/New Standards	N/A	Lenawee Co.
22		Baker 138/46 kV Substation (Crandall)	1,100	1	Project(s)	. Load carrying capabilities and voltage support	Avoid Overloads/offset transmission investment, cust-min saved	703,507	Van Buren Co.
23		LN111A SARANAC RBLD 4.5 MI 46 kV % *07	52	1	Project(s)	. Load carrying capabilities and voltage support	Mitigate Inadequate Clearance, increase capacity	N/A	Ionia Co.
24		SCOTT LAKE TO PULLMAN CASCO REBUILD	1,000	1	Project(s)	. Load carrying capabilities and voltage support	Avoid Overloads/Increase Capacity	N/A	Allegan Co.
25		LN119A/119W/119AD Hammond Rd R/W 8.05MI	777	0	n/a	. ROW procurement	Procure Right of Way needed to support projects	N/A	Grand Traverse Co.
26		LN032F UNION ST 46KV LINE R/W	100	0	n/a	. ROW procurement	Procure Right of Way needed to support projects	N/A	Grand Traverse Co.
27		**HVD Lines and Substations Capacity Total**	**34,956**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Benefit Type	(h) Benefit	(i) Location
	Capacity								
1	LVD Substations Capacity	BELVEDERE	186	0	Project	New Substations	Obligation To Serve - Customers Impacted	-	Allegan
2		CHANNEL	849	0	Project	New Substations	Obligation To Serve - Customers Impacted	-	Manistee
3		MERCURY	4,600	1	Project	New Substations	Obligation To Serve - Customers Impacted	142	Calhoun
4		QUICKSILVER	4,259	0	Project	New Substations	Obligation To Serve - Customers Impacted	-	Kent
5		VALENTINE	4,617	1	Project	New Substations	Obligation To Serve - Customers Impacted	551	Kalamazoo
6		ALLIANCE	1,530	1	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	69	Bay
7		DUQUITE	1,015	1	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	2,483	Arenac
8		GLEN LAKE	450	0	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	-	Leelanau
9		HICKORY	781	1	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	2,841	Muskegon
10		NEWARK	545	0	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	-	Oakland
11		NUNICA	554	0	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	-	Ottawa
12		RANGER LAKE	912	0	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	4,510	Iosco
13		WAKESHMA	2,100	1	Project	Increase Capacity at Existing Substation	Obligation To Serve - Customers Impacted	729	Kalamazoo
14		**LVD Substations Capacity Total**	**22,399**	**6**					

MICHIGAN PUBLIC SERVICE COMMISSION
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending (Test)	(d) Units	(e) Unit Type	(f) Investment Category	Benefit Type	Location
1	HVD Strategic Customers New Business	Two (2) new 138 kV dedicated customer Substations in west Michigan	7,652	2	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	west michigan
2	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in east Michigan	1,762	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	east Michigan
3	HVD Strategic Customers New Business	New 138 kV dedicated customer Substation in east Michigan	37,080	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	east Michigan
4	HVD Strategic Customers New Business	Capacity increase at existing 138 kV dedicated customer Substation in west Michigan	1,570	1	Projects	HVD New Business	Meet Obligation To Serve Customers, Economic Development	west Michigan
		HVD Strategic Customers New Business Total	**48,064**					

MICHIGAN PUBLIC SERVICE COMMISSION
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	New Business								
1	Metro New Business	200 FULTON CIVIL	4,000	1	Project	Primary Service	Grand Rapids	Primary Service; Estimated Added Load, kVA	-
2		275 FULTON ELEC	300	1	Project	Secondary Service	Grand Rapids	Secondary Service; Estimated Added Load; kVA	250
3		NEW COREWELL HOSPITAL TOWER CIVIL	1,500	1	Project	Primary Service	Grand Rapids	Secondary Service; Estimated Added Load; kVA	-
4		NEW KALAMAZOO CNTY ADMIN ELEC	650	1	Project	Secondary Service	Kalamazoo	Secondary Service; Estimated Added Load; kVA	600
5		NEW GENESEE CNTY COURTHOUSE ELEC	650	1	Project	Primary Service	Flint	Primary Service; Estimated Added Load, kVA	600
6		BEARINGER BLDG ELEC	637	1	Project	Secondary Service	Saginaw	Secondary Service; Estimated Added Load; kVA	300
7		**Metro New Business Total**	**7,737**						

MICHIGAN PUBLIC SERVICE COMMISSION
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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Asset Relocations								
1	Metro Relocations	WEALTHY ST (QUICKSILVER) ELEC	1,500	1	Project	Metro Relocations	Grand Rapids	Substation Coordination; customers impacted	492
2		DIVISION AVE; MICHIGAN TO COLDBROOK	12,500	1	Project	Metro Relocations	Grand Rapids	Coordination of Utilties; customers impacted	93
3		CORPORATION ALLEY CASTINGS	30	1	Project	Metro Relocations	Kalamazoo	Coordination of Utilties; customers impacted	35
4		GMI SUBSTATION EXITS	40	1	Project	Metro Relocations	Flint	Substation Coordination; customers impacted	2
5		ALDRICH DUCT MDOT M-21 REBUILD ELEC	2,000	1	Project	Metro Relocations	Flint	Coordination of Utilties; customers impacted	206
6		FOUNTAIN SUBSTATION EXITS	1,200	1	Project	Metro Relocations	Battle Creek	Substation Coordination; customers impacted	602
7		OAK STREET SUBSTATION EXITS	1,000	1	Project	Metro Relocations	Jackson	Substation Coordination; customers impacted	82
8		**Metro Relocations Total**	**18,270**						

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

SCOTT A. MCPHAIL II

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Automation Reliability Benefits

Case No.: U-22070
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Total Reliability Benefits	**3,250,369**	Avoided CMI
Rate Recovery Costs	**$ 7,947,330**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Automation Reliability Benefits

Case No.: U-22070
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ATR Loop Name	Feeder ID 1	Feeder ID 2	Average SAIDI Minutes Saved by ATR Loop	Total Customers	flagged as good ca	# of ATRs on loop	customers per zone	number of devices to add	new customers per zone	factor increase to SAIDI	Incremental ATR Loop SAIDI increase	CMI	project loaded cost	Cumulative cost
BROOKLYN02_CAMBRIDGE02	062402	127902	1.746057473	2030	x	3	508	1	406	20.0%	0.35	663,502	$ 120,000	$ 120,000
DIXIE01_MAYFAIR04	027801	064704	1.290013413	3068	x	3	767	1	614	20.0%	0.26	490,205	$ 120,000	$ 240,000
LEONARD01_MICHIGAN01	054801	070801	0.564024907	4713	x	3	1178	2	786	33.3%	0.19	357,216	$ 240,000	$ 480,000
DOEHLERJARVIS02_LEESTREET04	024102	090304	0.392249257	4905	x	3	1226	2	818	33.3%	0.13	248,425	$ 240,000	$ 720,000
WASHINGTON02_ORIOLE01	036202	054401	0.482892247	2781	x	2	927	1	695	25.0%	0.12	229,374	$ 120,000	$ 840,000
CEDARSPRINGS02_HULLSTREET02	028302	034402	0.338274	5517	x	3	1379	2	920	33.3%	0.11	214,240	$ 240,000	$ 1,080,000
DOEHLERJARVIS05_BOSTONSQUARE02	024105	032502	0.412504624	3090	x	3	773	1	618	20.0%	0.08	156,752	$ 120,000	$ 1,200,000
HARVEYSTREET02_HARVEYSTREET03	017002	017003	0.560391326	5342	x	5	890	1	763	14.3%	0.08	152,106	$ 120,000	$ 1,320,000
HOUGHTONHEIGHTS02_BACKUS01	039602	141201	0.210321406	9122	x	5	1520	3	1014	33.3%	0.07	133,204	$ 360,000	$ 1,680,000
COWANLAKE02_BRICKER01	022202	045301	0.335965993	2883	x	3	721	1	577	20.0%	0.07	127,667	$ 120,000	$ 1,800,000
BLINTON02_BLINTON03	002302	002303	0.194706753	4593	x	3	1148	2	766	33.3%	0.06	123,314	$ 240,000	$ 2,040,000
LEVELY02_PRICEROAD02	127702	154602	0.228412756	3195	x	3	799	1	639	20.0%	0.05	86,797	$ 120,000	$ 2,160,000
ROSEWOOD03_HAGERPARK02	133203	027902	0.082349912	6345	x	3	1586	3	906	42.9%	0.04	67,056	$ 360,000	$ 2,520,000
PEARLINE01_PEARLINE02	159501	159502	0.074834381	5731	x	3	1433	3	819	42.9%	0.03	60,937	$ 360,000	$ 2,880,000
ABERDEEN01_NORTHPARK01	031701	050301	0.096042207	5220	x	3	1305	2	870	33.3%	0.03	60,827	$ 240,000	$ 3,120,000
BOWEN03_KENTWOOD04	070603	086004	0.062949991	4236	x	3	1059	2	706	33.3%	0.02	39,868	$ 240,000	$ 3,360,000
EASTON01_EASTON02	024801	024802	0.14324107	4177	x	5	696	1	597	14.3%	0.02	38,880	$ 140,000	$ 3,500,000
IRISHROAD02_IRISHROAD03	142702	142703	0.138208011	5703	x	5	951	1	815	14.3%	0.02	37,514	$ 120,000	$ 3,620,000
IVANREST04_STONEGATE05	085904	095305	0.091835696	4630	x	5	772	1	661	14.3%	0.01	24,927	$ 120,000	$ 3,740,000
HOMESTEAD02_HONOR02	006802	078802	0.064510785	4313	x	5	719	1	616	14.3%	0.01	17,510	$ 120,000	$ 3,860,000

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Automation Reliability Benefits

Case No.: U-22070
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Date: June 2026

CAPITAL SPENDING ($000)
Project Name: Distribution Automation

Note: Capital Spending entered below should include any AFUDC. If a project was started in 2025 or before the total spend to date related to the project should be entered into the Balance as of 12/31/2025 (including any AFUDC).

Cost

Line Item	Schedule B-5 Category (Drop Down Menu)	Look-Up on B-5 Composite Depreciation Rate	Expected COD	Balance as of (12/31/2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	Date:	June 2026	2054	2055
1	Distribution	2.98%	2028	-	-	-	3,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Is Project AFUDC Eligible No

O&M Expense ($000)

Line Item	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1																															

Benefits

Line Item	Schedule B-5 Category (Drop Down Menu)	Look-Up on B-5 Composite Depreciation Rate	Expected COD	Balance as of (12/31/2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Is Project AFUDC Eligible No

O&M Expense ($000)

Line Item	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TO BE UPATED BY REVENUE REQUIREMENTS:

Per 2025 Historical - See Plant Model	
Depreciation Rate Table	
Distribution	2.98%
Production (Hydro)	19.76%
Production (Hydro Ludingt	2.77%
Production (Steam)	4.11%
Production (Battery)	6.91%
Production (Other)	2.47%
Intangibles	20.00%
E-GP Structures	2.56%
E-GP Computers	20.00%
E-GP Transportation	1.24%
E-GP Other	5.42%
C-GP Structures	1.56%
C-GP Computers	20.00%
C-GP Transportation	0.53%
C-GP Other	5.17%
Production Acq Adjustmer	3.45%
N/A - Line Not Used	

Pre-tax return (approved in U-21870)	7.54%
R&PP Tax (U-21870 Exh A-161 (BJV-1))	1.33%

Yes
No

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Automation Reliability Benefits

Case No.: U-22070
Exhibit No.: A-158 (SAM-1)
Page: 4 of 5
Witness: SAMcPhail
Date: June 2026

	Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
		Plant In Service																														
	1	Distribution Average Plant In Service	$ -	$ -	$ 1,750	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500
	2	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	4	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	5	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	6	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	7	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	8	**Total Average Plant in Service**	**$ -**	**$ -**	**$ 1,750**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**	**$ 3,500**
		Accumulated Deprecation Reserve																														
Cost	9	Beginning Depreciation Reserve	$ -	$ -	$ -	$ 26	$ 130	$ 234	$ 339	$ 443	$ 547	$ 651	$ 755	$ 859	$ 964	$ 1,068	$ 1,172	$ 1,276	$ 1,380	$ 1,485	$ 1,589	$ 1,693	$ 1,797	$ 1,901	$ 2,005	$ 2,110	$ 2,214	$ 2,318	$ 2,422	$ 2,526	$ 2,631	$ 2,735
	10	Deprecation Expense - Distribution	0	0	26	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104
	11	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	17	End Depreciation Reserve	$ -	$ -	$ 26	$ 130	$ 234	$ 339	$ 443	$ 547	$ 651	$ 755	$ 859	$ 964	$ 1,068	$ 1,172	$ 1,276	$ 1,380	$ 1,485	$ 1,589	$ 1,693	$ 1,797	$ 1,901	$ 2,005	$ 2,110	$ 2,214	$ 2,318	$ 2,422	$ 2,526	$ 2,631	$ 2,735	$ 2,839
	18	**Average Depreciation Reserve**	**$ -**	**$ -**	**$ 13**	**$ 78**	**$ 182**	**$ 286**	**$ 391**	**$ 495**	**$ 599**	**$ 703**	**$ 807**	**$ 912**	**$ 1,016**	**$ 1,120**	**$ 1,224**	**$ 1,328**	**$ 1,432**	**$ 1,537**	**$ 1,641**	**$ 1,745**	**$ 1,849**	**$ 1,953**	**$ 2,058**	**$ 2,162**	**$ 2,266**	**$ 2,370**	**$ 2,474**	**$ 2,578**	**$ 2,683**	**$ 2,787**
	19	**Total Average Rate Base**	**$ -**	**$ -**	**$ 1,737**	**$ 3,422**	**$ 3,318**	**$ 3,214**	**$ 3,109**	**$ 3,005**	**$ 2,901**	**$ 2,797**	**$ 2,693**	**$ 2,588**	**$ 2,484**	**$ 2,380**	**$ 2,276**	**$ 2,172**	**$ 2,068**	**$ 1,963**	**$ 1,859**	**$ 1,755**	**$ 1,651**	**$ 1,547**	**$ 1,442**	**$ 1,338**	**$ 1,234**	**$ 1,130**	**$ 1,026**	**$ 922**	**$ 817**	**$ 713**
		Plant In Service																														
	20	Distribution Average Plant In Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	21	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	22	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	23	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	24	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	26	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	27	**Total Average Plant in Service**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
		Accumulated Deprecation Reserve																														
Benefit	28	Beginning Depreciation Reserve	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	29	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	30	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	31	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	32	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	33	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	34	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	35	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	36	End Depreciation Reserve	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	37	**Average Depreciation Reserve**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	38	**Total Average Rate Base**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Automation Reliability Benefits

Case No.: U-22070
Exhibit No.: A-158 (SAM-1)
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Witness: SAMcPhail
Date: June 2026

Cost

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ -	$ -	$ 1,737	$ 3,422	$ 3,318	$ 3,214	$ 3,109	$ 3,005	$ 2,901	$ 2,797	$ 2,693	$ 2,588	$ 2,484	$ 2,380	$ 2,276	$ 2,172	$ 2,068	$ 1,963	$ 1,859	$ 1,755	$ 1,651	$ 1,547	$ 1,442	$ 1,338	$ 1,234	$ 1,130	$ 1,026	$ 922	$ 817	$ 713		
2	Total Return on Investment	$ -	$ -	$ 131	$ 258	$ 250	$ 242	$ 234	$ 227	$ 219	$ 211	$ 203	$ 195	$ 187	$ 179	$ 172	$ 164	$ 156	$ 148	$ 140	$ 132	$ 124	$ 117	$ 109	$ 101	$ 93	$ 85	$ 77	$ 69	$ 62	$ 54	**$ 4,340**
3	Total Depreciation Expense	-	-	26	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	**2,839**
4	Total R&PP Tax	-	-	23	46	44	43	42	40	39	37	36	35	33	32	30	29	28	26	25	23	22	21	19	18	16	15	14	12	11	10	**768**
5	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
6	Total Revenue Requirement	$ -	$ -	$ 180	$ 408	$ 399	$ 389	$ 380	$ 371	$ 362	$ 352	$ 343	$ 334	$ 325	$ 315	$ 306	$ 297	$ 288	$ 278	$ 269	$ 260	$ 251	$ 241	$ 232	$ 223	$ 214	$ 204	$ 195	$ 186	$ 177	$ 167	**$ 7,947**

Benefit

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
7	Total Return on Investment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
8	Total Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
9	Total R&PP Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
10	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
11	Total Revenue Requirement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**

Net Cost (Benefit)

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ -	$ -	$ 1,737	$ 3,422	$ 3,318	$ 3,214	$ 3,109	$ 3,005	$ 2,901	$ 2,797	$ 2,693	$ 2,588	$ 2,484	$ 2,380	$ 2,276	$ 2,172	$ 2,068	$ 1,963	$ 1,859	$ 1,755	$ 1,651	$ 1,547	$ 1,442	$ 1,338	$ 1,234	$ 1,130	$ 1,026	$ 922	$ 817	$ 713		
12	Total Return on Investment	-	-	131	258	250	242	234	227	219	211	203	195	187	179	172	164	156	148	140	132	124	117	109	101	93	85	77	69	62	54	**$ 4,340**
13	Total Depreciation Expense	-	-	26	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	**2,839**
14	Total R&PP Tax	-	-	23	46	44	43	42	40	39	37	36	35	33	32	30	29	28	26	25	23	22	21	19	18	16	15	14	12	11	10	**768**
15	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	Total Revenue Requirement	$ -	$ -	$ 180	$ 408	$ 399	$ 389	$ 380	$ 371	$ 362	$ 352	$ 343	$ 334	$ 325	$ 315	$ 306	$ 297	$ 288	$ 278	$ 269	$ 260	$ 251	$ 241	$ 232	$ 223	$ 214	$ 204	$ 195	$ 186	$ 177	$ 167	**$ 7,947**

Footnotes:
Pre-tax return 7.54%
R&PP Tax 1.33%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Automation Projects
Summary Projected Electric Capital Expenditures
For the Test Period 12 Months Ending April, 30 2028
($000)

Case No.: U-22070
Exhibit No.: A-159 (SAM-2)
Page: 1 of 1
Witness: SAMcPhail
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2026-2027 Test Year Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
1	Grid Automation	BROOKLYN02_CAMBRIDGE02	$120,000	1	ATR	Automation - Recloser	COLUMBIA Township	CMI	663,502
2	Grid Automation	DIXIE01_MAYFAIR04	$120,000	1	ATR	Automation - Recloser	MOUNT MORRIS Township	CMI	490,205
3	Grid Automation	LEONARD01_MICHIGAN01	$240,000	2	ATR	Automation - Recloser	GRAND RAPIDS	CMI	357,216
4	Grid Automation	DOEHLERJARVIS02_LEESTREET04	$240,000	2	ATR	Automation - Recloser	GRAND RAPIDS	CMI	248,425
5	Grid Automation	WASHINGTON02_ORIOLE01	$120,000	1	ATR	Automation - Recloser	LUDINGTON	CMI	229,374
6	Grid Automation	CEDARSPRINGS02_HULLSTREET02	$240,000	2	ATR	Automation - Recloser	CEDAR SPRINGS	CMI	214,240
7	Grid Automation	DOEHLERJARVIS05_BOSTONSQUARE02	$120,000	1	ATR	Automation - Recloser	GRAND RAPIDS	CMI	156,752
8	Grid Automation	HARVEYSTREET02_HARVEYSTREET03	$120,000	1	ATR	Automation - Recloser	GRAND RAPIDS	CMI	152,106
9	Grid Automation	HOUGHTONHEIGHTS02_BACKUS01	$360,000	3	ATR	Automation - Recloser	ROSCOMMON Township	CMI	133,204
10	Grid Automation	COWANLAKE02_BRICKER01	$120,000	1	ATR	Automation - Recloser	CANNON Township	CMI	127,667
11	Grid Automation	BLINTON02_BLINTON03	$240,000	2	ATR	Automation - Recloser	GRAND RAPIDS Township	CMI	123,314
12	Grid Automation	LEVELY02_PRICEROAD02	$120,000	1	ATR	Automation - Recloser	EDENVILLE Township	CMI	86,797
13	Grid Automation	ROSEWOOD03_HAGERPARK02	$360,000	3	ATR	Automation - Recloser	GEORGETOWN Township	CMI	67,056
14	Grid Automation	PEARLINE01_PEARLINE02	$360,000	3	ATR	Automation - Recloser	ALLENDALE Township	CMI	60,937
15	Grid Automation	ABERDEEN01_NORTHPARK01	$240,000	2	ATR	Automation - Recloser	GRAND RAPIDS	CMI	60,827
16	Grid Automation	BOWEN03_KENTWOOD04	$240,000	2	ATR	Automation - Recloser	GRAND RAPIDS	CMI	39,868
17	Grid Automation	EASTON01_EASTON02	$140,000	1	ATR	Automation - Recloser	EASTON Township	CMI	38,880
			$3,500,000	**29**					

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Line Regulator Controller Upgrades BCA Methodology

Case No.: U-22070
Exhibit No.: A-160 (SAM-3)
Page: 1 of 6
Witness: SAMcPhail
Date: June 2026

Line No.	(a)	(b)	
1	**Total Benefits**	**$23,606,493**	
2	**Total Reliability Benefits**	**56,625**	**Avoided CMI**
3	**Total Costs**	**$15,129,138**	
4	**NPV**	**$8,477,355**	
5	**Rate Recovery Costs**	**$18,636,699**	
6	**Rate Recovery Benefits**	**$44,544,748**	
7	**Net Rate Recovery**	**$25,908,049**	

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

Reductions in Distribution (Labor & Material)

Savings due to a reduction in Routine Truck Rolls		
	$500	Routine Truck Rolls are saved because all Line Regulator Controls can be manipulated remotely in lieu of having to send personnel there to make voltage adjustments
System Population	1,889,301	
Average # of hours for Routine Work	1	
# of LVD Line Regulator Locations	1800	
Percentage of LVD Circuits that require adjustments to Line Voltage Regulators over the course of a Year	10%	It can be assumed that 10% of all Line Regulator Locations experience voltage adjustments over a 10 year period on average
# of LVD Line Regulator Locations Requiring Adjustments each Year	180	
Annual Average Savings due to Routine Truck Rolls	$90,000	
Reg Material & Labor Savings due to Life Extension for Regulator Tanks		
Average Regulator Tank Cost	$20,000	About 50 Reg Tank replacements take place on average in any given year across the LVD Fleet. Over a ten year period about 500 Regulator Tank replacements will be necessary to restore full functionality to LVD Line Regulator Locations. Regulator Tanks Useful life spans will be extended due to the preventaive maintenance tapping feature which has been turned on for all new replacement Regulator Controls. It is reasonable to assume that annual Regulator Tank Replacement will be reduced by at least 25% on an annual basis due to this preventative maintenance function over a ten year period.
Annual Reduction in # of Tank Replacements	12.5	
Storeroom Loadings Factor	2.3	
Average # of Regulator Tank Replacement per Year	50	
Average # of CE Crew Manhours for a Typical Tank Replacement	8	Includes Electric Field Lab Support functions including replacement of failed tanks at the specific location
CE Crew Hourly Rate (Loaded)	$440	
Average # of EFL Manhours for a Typical Tank Replacement	2.5	Includes Line Regulator Control Operation and Wiring Activities
EFL Hourly Rate (Loaded)	$110	
Total Average Annual Cost Labor Savings	$47,438	
Average Material Savings per Year due to Reg Tank Life Extension	$622,438	
Cellular Cost Savings due to Modem Configurations		
$7.00 per Month (250mb per month per device) based on Actual Data Usage from IT for a sample of Scada enabled Reg Devices	$7	
~900 Multiphase Pole Locations (3 phase)	900	
~340 Multiphase Pole Locations (2 phase)	340	
Annual Cellular Cost for a Single Phase Control 3 phase location	$226,800	
Annual Cellular Cost for a Single Phase Control 2 phase location	$57,120	
Annual Cellular Cost for a Multiiphase Control 3 phase location	$75,600	
Annual Cellular Cost for a Multiiphase Control 2 phase location	$28,560	
Annual Cellular Savings for a Multiphase Control 3 phase location	$151,200	
Annual Cellular Savings for a Multiphase Control 2 phase location	$28,560	
Full deployment starts in 2027 so full value of Cellular savings starts in the year 2027		
% Complete Deployment after 2024	75.33%	
% Complete Deployment after 2025	87.56%	
Total Annual Cellular Savings@100%	$179,760	
Reg Material Avoided Costs due to Replacement of Line Regulator Controls		Because Line Regulator Controls have been replaced across the fleet with all new Controls that have a 10 year Warranty at about 1800 locations across the fleet, a significant amount of costs to replace these controls has been avoided for the next ten years. Conservatively, we can assume that about 10% of these controls would have failed each year starting with the year 2027. In addition, we know that without the execution of this project these controls would have been replaced with Single Phase Controls paired with their corresponding tanks. This substantial cost in future years has been AVOIDED due to the executon of the project.
# of Multiphase Controls Installed 3 Phase Locations	900	
# of Single Phase Controls Replaced at Multiphase Locations	2700	
# of Multiphase Controls Installed 2 Phase Locations	350	
# of Single Phase Controls Replaced at 2 Phase Multiphase Locations	700	
# of Single Phase Controls Replaced at Single Phase locations	1000	
TOTAL # of Single Phase Controls Replaced during the Project	4400	
Average Cost of a Single Phase Control over the next 10 years considering 5% inflation over those years	$7,000	
Current Cost of a Single Phase Reg Control	$6,400	
Average Lifespan of a Regulator Control	20 to 25 years	Reference: Regulator Control Supplier
Total Estimated # of Controls that will fail during a Time Period starting in the year 2027 for the next ten years.		Large Sample Size of 790 were evaluated. Of that sample size 163 were year 2000 or older (pre-2000) representing about 20% overall. So, an extrapolation across the entire population of 4400 Controls results in about 4400 *20% or about 880 Controls that are likely to fail during the 10 year period starting in 2027
Estimated # of Controls that were likely to fail during the time period after completion of the project starting in 2027 over a ten year period	800	
Apply Loading factor of 2.3 assuming these Controls would have been from Stores.	2.3	
Average Annual Rate of Replacement for Reg Controls starting in 2027	10%	
Average Annual Reg Control Replacement Costs starting in 2027	$1,288,000	

Customer Savings (MWh)

Reg-enabled MW Peak Reduction Benefits (MWh)		
Cost/MWh ($)	$32.15	
# of Circuits with CVR (as of 12/31/2024):	430	
2030 # of Circuits	900	
# of CVR circuits with Line Regs:	73	
# of Line Regs supporting CVR:	42	
# of available line regs on CVR circuits:	211	
% of CVR-enabled line regs:	20%	
Expected MWh savings of CVR through 2030 (MWh):	271582	
% of CVR-enabled line regs vs. # of line regs on LVD system:	2%	
Assume 2% support of line regs for expected MWh savings (MWh):	6336.91	Total MWh savings through 2030 (NOT per year)
Assume 2% support of line regs for expected Cost/MWh savings ($):	$203,731.76	Total $ savings through 2030 (NOT per year)
Average Annual Benefit for expected Cost/MWh savings ($):	$18,521.07	

CMI

# of Customers Fleetwide	1,889,301	
Average Length of a Line Regulator Caused Outage (Minutes)	30	
Average # of Customers on an LVD Circuit Outage	151	
Annual Average # of Outages Avoided due to Automatic Preventative Maintenance is equal to the # of Reg Tank Replacements that do not have to happen in a year	13	
Total Average Custimer Minutes Interrupted (CMI) Saved on an Annual Basis	56625	

Benefits Calculations

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Monetized Benefits:													
$ 1,080,000	Avoided Truck Roll Savings	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000	$90,000
$ 7,469,250	Material Savings due to Life Extension	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438	$622,438
$ 222,253	Reg Enabled CVR Benefits	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521	$18,521
$ 1,954,990	Cellular Cost Savings due to Modem Configurations	$0.00	$157,389.87	$179,760	$179,760	$179,760	$179,760	$179,760	$179,760	$179,760	$179,760	$179,760	$179,760
$ 12,880,000	Material Savings due to Failed Reg Controls	$0	$0	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000	$1,288,000
		$731	$888	$2,199	$2,199	$2,199	$2,199	$2,199	$2,199	$2,199	$2,199	$2,199	$2,199

Costs Calculations

Assumptions

Post-Tax WACC (%): 7.25%

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capital Spend ($):	$ 15,129,138	$ 8,000,000	$ 7,646,000										
		8000	7646										

The manufacturers date was recorded from the nameplate on the 790 regulator tanks during line regulator deployment activities
This is considered to be a large sample size against a total population of 1800 locations

The large sample size of 790 were evaluated. Of that sample size 163 were year 2000 or older (pre-2000) representing about 20% overall. So, an extrapolation across the entire population of 4000 controls results in about 4000 *20% or about 800 controls that are likely to fail during the 10 year period starting in 2027 based on average lifespan of 20 to 25 years for a regulator control

Here are the numbers associated with the 163 that were year 2000 or older

Time Span	# of Controls
Pre-1990	1
1990-1995	49
1996-2000	113
2001-2005	116
2006-2010	171
2006	35
Other (Remainder)	450
	340
Total Sample Size	790

Consequently, a total of 163 are the year 2000 or older (pre-2000) or about 20% of the total sample size.
163

% of Sample Size 2000 year or older versus the total Sample Size **20.63%**

So this large sample size is likely representative of the total population and we can extrapolate across the entire populuation to determine the age composition of controls across the LVD fleet.

CAPITAL SPENDING ($000)
Project Name: Line Regulator Controller Upgrades

Note: Capital Spending entered below should include any AFUDC. If a project was started in 2025 or before the total spend to date related to the project should be entered into the Balance as of 12/31/2025 (including any AFUDC).

Cost

Line Item	Schedule B-5 Category (Drop Down Menu)	Look-Up on B-5 Composite Deprecation Rate	Expected COD	Balance as of (12/31/2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1	Distribution	2.98%	2028	-	7,646	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Is Project AFUDC Eligible No

O&M Expense ($000)

Line Item	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1																															

Benefits

Line Item	Schedule B-5 Category (Drop Down Menu)	Look-Up on B-5 Composite Deprecation Rate	Expected COD	Balance as of (12/31/2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1	Distribution	2.98%	2029	-	$622	$1,910	$1,910	$1,910	$1,910	$1,910	$1,910	$1,910	$1,910	$1,910	$1,910	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Is Project AFUDC Eligible No

O&M Expense ($000)

Line Item	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1		266	288	288	288	288	288	288	288	288	288	288	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TO BE UPATED BY REVENUE REQUIREMENTS:

Per 2025 Historical - See Plant Model	
Depreciation Rate Table	
Distribution	2.98%
Production (Hydro)	19.76%
Production (Hydro Ludingtc	2.77%
Production (Steam)	4.11%
Production (Battery)	6.91%
Production (Other)	2.47%
Intangibles	20.00%
E-GP Structures	2.56%
E-GP Computers	20.00%
E-GP Transportation	1.24%
E-GP Other	5.42%
C-GP Structures	1.56%
C-GP Computers	20.00%
C-GP Transportation	0.53%
C-GP Other	5.17%
Production Acq Adjustment	3.45%
N/A - Line Not Used	

Pre-tax return (approved in U-21870)	7.54%
R&PP Tax (U-21870 Exh A-161 (BJV-1))	1.33%

Yes
No

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Line Regulator Controller Upgrades BCA Methodology

Case No.: U-22070
Exhibit No.: A-160 (SAM-3)
Page: 5 of 6
Witness: SAMcPhail
Date: June 2026

	Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Cost		**Plant In Service**																														
	1	Distribution Average Plant In Service	$ 3,823	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646	$ 7,646
	2	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	4	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	5	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	6	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	7	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	8	**Total Average Plant in Service**	**$ 3,823**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**	**$ 7,646**
		Accumulated Depreciation Reserve																														
	9	Beginning Depreciation Reserve	$ -	$ -	$ -	$ 114	$ 341	$ 569	$ 797	$ 1,024	$ 1,252	$ 1,479	$ 1,707	$ 1,935	$ 2,162	$ 2,390	$ 2,617	$ 2,845	$ 3,072	$ 3,300	$ 3,528	$ 3,755	$ 3,983	$ 4,210	$ 4,438	$ 4,666	$ 4,893	$ 5,121	$ 5,348	$ 5,576	$ 5,804	$ 6,031
	10	Depreciation Expense - Distribution	0	0	114	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
	11	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	17	End Depreciation Reserve	$ -	$ -	$ 114	$ 341	$ 569	$ 797	$ 1,024	$ 1,252	$ 1,479	$ 1,707	$ 1,935	$ 2,162	$ 2,390	$ 2,617	$ 2,845	$ 3,072	$ 3,300	$ 3,528	$ 3,755	$ 3,983	$ 4,210	$ 4,438	$ 4,666	$ 4,893	$ 5,121	$ 5,348	$ 5,576	$ 5,804	$ 6,031	$ 6,259
	18	**Average Depreciation Reserve**	**$ -**	**$ -**	**$ 57**	**$ 228**	**$ 455**	**$ 683**	**$ 910**	**$ 1,138**	**$ 1,366**	**$ 1,593**	**$ 1,821**	**$ 2,048**	**$ 2,276**	**$ 2,503**	**$ 2,731**	**$ 2,959**	**$ 3,186**	**$ 3,414**	**$ 3,641**	**$ 3,869**	**$ 4,097**	**$ 4,324**	**$ 4,552**	**$ 4,779**	**$ 5,007**	**$ 5,235**	**$ 5,462**	**$ 5,690**	**$ 5,917**	**$ 6,145**
	19	**Total Average Rate Base**	**$ 3,823**	**$ 7,646**	**$ 7,589**	**$ 7,418**	**$ 7,191**	**$ 6,963**	**$ 6,736**	**$ 6,508**	**$ 6,280**	**$ 6,053**	**$ 5,825**	**$ 5,598**	**$ 5,370**	**$ 5,143**	**$ 4,915**	**$ 4,687**	**$ 4,460**	**$ 4,232**	**$ 4,005**	**$ 3,777**	**$ 3,549**	**$ 3,322**	**$ 3,094**	**$ 2,867**	**$ 2,639**	**$ 2,411**	**$ 2,184**	**$ 1,956**	**$ 1,729**	**$ 1,501**
Benefit		**Plant In Service**																														
	20	Distribution Average Plant In Service	$ 311	$ 1,578	$ 3,488	$ 5,399	$ 7,309	$ 9,219	$ 11,130	$ 13,040	$ 14,951	$ 16,861	$ 18,772	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727	$ 19,727
	21	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	22	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	23	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	24	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	26	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	27	**Total Average Plant in Service**	**$ 311**	**$ 1,578**	**$ 3,488**	**$ 5,399**	**$ 7,309**	**$ 9,219**	**$ 11,130**	**$ 13,040**	**$ 14,951**	**$ 16,861**	**$ 18,772**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**	**$ 19,727**
		Accumulated Depreciation Reserve																														
	28	Beginning Depreciation Reserve	$ -	$ -	$ -	$ -	$ 80	$ 298	$ 572	$ 904	$ 1,292	$ 1,737	$ 2,239	$ 2,797	$ 3,385	$ 3,972	$ 4,559	$ 5,146	$ 5,733	$ 6,321	$ 6,908	$ 7,495	$ 8,082	$ 8,669	$ 9,256	$ 9,844	$ 10,431	$ 11,018	$ 11,605	$ 12,192	$ 12,780	$ 13,367
	29	Depreciation Expense - Distribution	0	0	0	80	218	274	331	388	445	502	559	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587
	30	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	31	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	32	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	33	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	34	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	35	Depreciation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	36	End Depreciation Reserve	$ -	$ -	$ -	$ 80	$ 298	$ 572	$ 904	$ 1,292	$ 1,737	$ 2,239	$ 2,797	$ 3,385	$ 3,972	$ 4,559	$ 5,146	$ 5,733	$ 6,321	$ 6,908	$ 7,495	$ 8,082	$ 8,669	$ 9,256	$ 9,844	$ 10,431	$ 11,018	$ 11,605	$ 12,192	$ 12,780	$ 13,367	$ 13,954
	37	**Average Depreciation Reserve**	**$ -**	**$ -**	**$ -**	**$ 40**	**$ 189**	**$ 435**	**$ 738**	**$ 1,098**	**$ 1,514**	**$ 1,988**	**$ 2,518**	**$ 3,091**	**$ 3,678**	**$ 4,265**	**$ 4,853**	**$ 5,440**	**$ 6,027**	**$ 6,614**	**$ 7,201**	**$ 7,789**	**$ 8,376**	**$ 8,963**	**$ 9,550**	**$ 10,137**	**$ 10,724**	**$ 11,312**	**$ 11,899**	**$ 12,486**	**$ 13,073**	**$ 13,660**
	38	**Total Average Rate Base**	**$ 311**	**$ 1,578**	**$ 3,488**	**$ 5,358**	**$ 7,120**	**$ 8,784**	**$ 10,392**	**$ 11,943**	**$ 13,436**	**$ 14,873**	**$ 16,254**	**$ 16,636**	**$ 16,049**	**$ 15,461**	**$ 14,874**	**$ 14,287**	**$ 13,700**	**$ 13,113**	**$ 12,525**	**$ 11,938**	**$ 11,351**	**$ 10,764**	**$ 10,177**	**$ 9,590**	**$ 9,002**	**$ 8,415**	**$ 7,828**	**$ 7,241**	**$ 6,654**	**$ 6,066**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Line Regulator Controller Upgrades BCA Methodology

Case No.: U-22070
Exhibit No.: A-160 (SAM-3)
Page: 6 of 6
Witness: SAMcPhail
Date: June 2026

Cost

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ 3,823	$ 7,646	$ 7,589	$ 7,418	$ 7,191	$ 6,963	$ 6,736	$ 6,508	$ 6,280	$ 6,053	$ 5,825	$ 5,598	$ 5,370	$ 5,143	$ 4,915	$ 4,687	$ 4,460	$ 4,232	$ 4,005	$ 3,777	$ 3,549	$ 3,322	$ 3,094	$ 2,867	$ 2,639	$ 2,411	$ 2,184	$ 1,956	$ 1,729	$ 1,501	
2	Total Return on Investment	$ 288	$ 577	$ 572	$ 559	$ 542	$ 525	$ 508	$ 491	$ 474	$ 456	$ 439	$ 422	$ 405	$ 388	$ 371	$ 353	$ 336	$ 319	$ 302	$ 285	$ 268	$ 250	$ 233	$ 216	$ 199	$ 182	$ 165	$ 148	$ 130	$ 113	**$ 10,516**
3	Total Depreciation Expense	-	-	114	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	**6,259**
4	Total R&PP Tax	51	102	101	99	96	93	90	87	84	81	78	75	72	69	66	63	60	56	53	50	47	44	41	38	35	32	29	26	23	20	**1,862**
5	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
6	Total Revenue Requirement	$ 339	$ 679	$ 787	$ 886	$ 866	$ 846	$ 825	$ 805	$ 785	$ 765	$ 745	$ 724	$ 704	$ 684	$ 664	$ 644	$ 623	$ 603	$ 583	$ 563	$ 543	$ 522	$ 502	$ 482	$ 462	$ 442	$ 421	$ 401	$ 381	$ 361	**$ 18,637**

Benefit

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ 311	$ 1,578	$ 3,488	$ 5,358	$ 7,120	$ 8,784	$ 10,392	$ 11,943	$ 13,436	$ 14,873	$ 16,254	$ 16,636	$ 16,049	$ 15,461	$ 14,874	$ 14,287	$ 13,700	$ 13,113	$ 12,525	$ 11,938	$ 11,351	$ 10,764	$ 10,177	$ 9,590	$ 9,002	$ 8,415	$ 7,828	$ 7,241	$ 6,654	$ 6,066	
7	Total Return on Investment	$ 23	$ 119	$ 263	$ 404	$ 537	$ 662	$ 784	$ 900	$ 1,013	$ 1,121	$ 1,226	$ 1,254	$ 1,210	$ 1,166	$ 1,122	$ 1,077	$ 1,033	$ 989	$ 944	$ 900	$ 856	$ 812	$ 767	$ 723	$ 679	$ 635	$ 590	$ 546	$ 502	$ 457	**$ 23,314**
8	Total Depreciation Expense	-	-	-	80	218	274	331	388	445	502	559	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	**13,954**
9	Total R&PP Tax	4	21	47	72	95	117	139	159	179	199	217	222	214	206	199	191	183	175	167	159	152	144	136	128	120	112	104	97	89	81	**4,128**
10	Total O&M Expense	266	288	288	288	288	288	288	288	288	288	288	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,149**
11	Total Revenue Requirement	$ 294	$ 428	$ 598	$ 844	$ 1,138	$ 1,342	$ 1,542	$ 1,736	$ 1,926	$ 2,110	$ 2,290	$ 2,064	$ 2,011	$ 1,959	$ 1,907	$ 1,855	$ 1,803	$ 1,751	$ 1,699	$ 1,647	$ 1,595	$ 1,542	$ 1,490	$ 1,438	$ 1,386	$ 1,334	$ 1,282	$ 1,230	$ 1,178	$ 1,126	**$ 44,545**

Net Cost (Benefit)

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ 3,512	$ 6,068	$ 4,101	$ 2,060	$ 71	$ (1,821)	$ (3,656)	$ (5,435)	$ (7,156)	$ (8,821)	$ (10,428)	$ (11,038)	$ (10,678)	$ (10,319)	$ (9,959)	$ (9,600)	$ (9,240)	$ (8,881)	$ (8,521)	$ (8,161)	$ (7,802)	$ (7,442)	$ (7,083)	$ (6,723)	$ (6,363)	$ (6,004)	$ (5,644)	$ (5,285)	$ (4,925)	$ (4,565)	
12	Total Return on Investment	265	458	309	155	5	(137)	(276)	(410)	(540)	(665)	(786)	(832)	(805)	(778)	(751)	(724)	(697)	(670)	(642)	(615)	(588)	(561)	(534)	(507)	(480)	(453)	(426)	(398)	(371)	(344)	**$ (12,798)**
13	Total Depreciation Expense	-	-	114	147	10	(47)	(104)	(161)	(217)	(274)	(331)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	(360)	**(7,695)**
14	Total R&PP Tax	47	81	55	28	1	(24)	(49)	(73)	(96)	(118)	(139)	(147)	(143)	(138)	(133)	(128)	(123)	(119)	(114)	(109)	(104)	(99)	(95)	(90)	(85)	(80)	(75)	(71)	(66)	(61)	**(2,266)**
15	Total O&M Expense	(266)	(288)	(288)	(288)	(288)	(288)	(288)	(288)	(288)	(288)	(288)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(3,149)**
16	Total Revenue Requirement	$ 46	$ 250	$ 189	$ 42	$ (272)	$ (497)	$ (716)	$ (931)	$ (1,141)	$ (1,345)	$ (1,545)	$ (1,339)	$ (1,307)	$ (1,275)	$ (1,243)	$ (1,212)	$ (1,180)	$ (1,148)	$ (1,116)	$ (1,084)	$ (1,052)	$ (1,020)	$ (988)	$ (956)	$ (924)	$ (892)	$ (861)	$ (829)	$ (797)	$ (765)	**$ (25,908)**

Footnotes:
Pre-tax return 7.54%
R&PP Tax 1.33%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Projects
Summary Projected Electric Capital Expenditures
For the Bridge Year 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-161 (SAM-4)
Page: 1 of 1
Witness: SAMcPhail
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected 2026-2027 Bridge Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
1	Grid Automation	REG25_ALCONA DAM_CURTISVILLE	$27,052	1	Regulator Location	Automation - Regulator Controllers	CURTIS Township	Customers Impacted	383
2	Grid Automation	REG26_FOURTEENTH STREET_LIBERTY STREET	$27,052	1	Regulator Location	Automation - Regulator Controllers	FLINT	Customers Impacted	1424
3	Grid Automation	REG25_BATH_BATH	$27,052	1	Regulator Location	Automation - Regulator Controllers	OLIVE Township	Customers Impacted	586
4	Grid Automation	REG25_BELDING_CITY	$27,052	1	Regulator Location	Automation - Regulator Controllers	OGDEN Township	Customers Impacted	218
5	Grid Automation	REG26_CHESANING_PEET	$54,104	2	Regulator Location	Automation - Regulator Controllers	ALBEE Township	Customers Impacted	291
6	Grid Automation	REG25_CEDAR LAKE_VAN ETTEN	$27,052	1	Regulator Location	Automation - Regulator Controllers	OSCODA Township	Customers Impacted	615
7	Grid Automation	REG25_DERBY_DERBY	$27,052	1	Regulator Location	Automation - Regulator Controllers	DOUGLASS Township	Customers Impacted	110
8	Grid Automation	REG26_CENTER ROAD_EVERGREEN	$27,052	1	Regulator Location	Automation - Regulator Controllers	FLINT	Customers Impacted	103
9	Grid Automation	REG26_CHESANING_OAKLEY	$54,104	2	Regulator Location	Automation - Regulator Controllers	RUSH Township	Customers Impacted	687
10	Grid Automation	REG25_FREEPORT_CARLTON CENTER	$81,156	3	Regulator Location	Automation - Regulator Controllers	BOWNE Township	Customers Impacted	375
11	Grid Automation	REG25_GERRISH_GOLF CLUB	$27,052	1	Regulator Location	Automation - Regulator Controllers	CLAM LK Township	Customers Impacted	538
12	Grid Automation	REG25_GERRISH_LEGION	$81,156	3	Regulator Location	Automation - Regulator Controllers	GRAYLING Township	Customers Impacted	530
13	Grid Automation	REG25_GILSON_WYMAN	$27,052	1	Regulator Location	Automation - Regulator Controllers	MILLBROOK Township	Customers Impacted	41
14	Grid Automation	REG25_GUN LAKE_ENGLAND	$27,052	1	Regulator Location	Automation - Regulator Controllers	ORANGEVILLE Township	Customers Impacted	1303
15	Grid Automation	REG25_HARRIETTA_BOON	$27,052	1	Regulator Location	Automation - Regulator Controllers	DICKSON Township	Customers Impacted	73
16	Grid Automation	REG25_HARRIETTA_CABERFAE	$27,052	1	Regulator Location	Automation - Regulator Controllers	BOON Township	Customers Impacted	169
17	Grid Automation	REG25_HIGH BRIDGE_KALEVA	$27,052	1	Regulator Location	Automation - Regulator Controllers	KALEVA	Customers Impacted	340
18	Grid Automation	REG25_HOLTON_MAPLE ISLAND	$27,052	1	Regulator Location	Automation - Regulator Controllers	DAYTON Township	Customers Impacted	340
19	Grid Automation	REG25_HONOR_PLATTE	$27,052	1	Regulator Location	Automation - Regulator Controllers	HOMESTEAD Township	Customers Impacted	835
20	Grid Automation	REG25_ITHACA_COURT HOUSE	$27,052	1	Regulator Location	Automation - Regulator Controllers	NEWARK Township	Customers Impacted	377
21	Grid Automation	REG25_KINGSLEY_CENTER ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	HAMPTON Township	Customers Impacted	145
22	Grid Automation	REG25_MARKER LAKE_KYSER ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	BOSTON Township	Customers Impacted	407
23	Grid Automation	REG25_NINETEEN MILE RD_INDUSTRIAL PARK	$27,052	1	Regulator Location	Automation - Regulator Controllers	BIG RAPIDS Township	Customers Impacted	101
24	Grid Automation	REG25_PIERSON_PIERSON	$27,052	1	Regulator Location	Automation - Regulator Controllers	MT MORRIS Township	Customers Impacted	566
25	Grid Automation	REG25_PRESCOTT_LOGAN	$54,104	2	Regulator Location	Automation - Regulator Controllers	RICHLAND Township	Customers Impacted	387
26	Grid Automation	REG25_PRESCOTT_MAPLE RIDGE	$27,052	1	Regulator Location	Automation - Regulator Controllers	CARROLLTON Township	Customers Impacted	510
27	Grid Automation	REG25_REMUS_MECOSTA	$27,052	1	Regulator Location	Automation - Regulator Controllers	WHEATLAND Township	Customers Impacted	1039
28	Grid Automation	REG25_ROCKFORD_WOLVERINE	$27,052	1	Regulator Location	Automation - Regulator Controllers	WILMOT Township	Customers Impacted	148
29	Grid Automation	REG25_SHERIDAN_FENWICK	$54,104	2	Regulator Location	Automation - Regulator Controllers	EVERGREEN Township	Customers Impacted	394
30	Grid Automation	REG25_STANDISH_STANDISH	$54,104	2	Regulator Location	Automation - Regulator Controllers	ARENAC Township	Customers Impacted	1176
31	Grid Automation	REG25_STANWOOD_TYLER ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	AETNA Township	Customers Impacted	278
32	Grid Automation	REG25_VANDERBILT_WOLVERINE	$27,052	1	Regulator Location	Automation - Regulator Controllers	WILMOT Township	Customers Impacted	469
33	Grid Automation	REG26_BLACK RIVER_ZEELAND	$27,052	1	Regulator Location	Automation - Regulator Controllers	HOLLAND Township	Customers Impacted	144
34	Grid Automation	REG26_CONVIS_MAR CREEK	$27,052	1	Regulator Location	Automation - Regulator Controllers	PENNFIELD Township	Customers Impacted	432
35	Grid Automation	REG26_CUTLERVILLE_SPARTAN	$27,052	1	Regulator Location	Automation - Regulator Controllers	BYRON Township	Customers Impacted	375
36	Grid Automation	REG26_DORR CORNERS_RED RUN	$27,052	1	Regulator Location	Automation - Regulator Controllers	DORR Township	Customers Impacted	1197
37	Grid Automation	REG26_EMERSON_KILMER	$27,052	1	Regulator Location	Automation - Regulator Controllers	CALEDONIA Township	Customers Impacted	1106
38	Grid Automation	REG26_FENNVILLE_COMMERCIAL	$27,052	1	Regulator Location	Automation - Regulator Controllers	CLYDE Township	Customers Impacted	160
39	Grid Automation	REG26_FENNVILLE_PEACH BELT	$27,052	1	Regulator Location	Automation - Regulator Controllers	SAUGATUCK Township	Customers Impacted	135
40	Grid Automation	REG26_FINE LAKE_BRISTOL	$27,052	1	Regulator Location	Automation - Regulator Controllers	JOHNSTOWN Township	Customers Impacted	202
41	Grid Automation	REG26_FINE LAKE_DOWLING	$27,052	1	Regulator Location	Automation - Regulator Controllers	JOHNSTOWN Township	Customers Impacted	88
42	Grid Automation	REG26_FOOTE HYDRO_DISTRIBUTION	$27,052	1	Regulator Location	Automation - Regulator Controllers	LAFAYETTE Township	Customers Impacted	338
43	Grid Automation	REG26_FOREMAN_VERGENNES	$27,052	1	Regulator Location	Automation - Regulator Controllers	ADA Township	Customers Impacted	109
44	Grid Automation	REG26_GREENBUSH_GREENBUSH	$27,052	1	Regulator Location	Automation - Regulator Controllers	GREENBUSH Township	Customers Impacted	364
45	Grid Automation	REG26_GREENBUSH_HARRISVILLE	$27,052	1	Regulator Location	Automation - Regulator Controllers	HARRISVILLE Township	Customers Impacted	687
46	Grid Automation	REG26_HAGER PARK_HAGER PARK	$27,052	1	Regulator Location	Automation - Regulator Controllers	GEORGETOWN Township	Customers Impacted	696
47	Grid Automation	REG26_HALLS LAKE_HALLS LAKE	$27,052	1	Regulator Location	Automation - Regulator Controllers	MARENGO Township	Customers Impacted	57
48	Grid Automation	REG26_HARLEM_BORCULO	$27,052	1	Regulator Location	Automation - Regulator Controllers	OLIVE Township	Customers Impacted	87
49	Grid Automation	REG26_KENTWOOD_PARIS PARK	$27,052	1	Regulator Location	Automation - Regulator Controllers	GAINES Township	Customers Impacted	1229
50	Grid Automation	REG26_LABARGE_ALASKA	$54,104	2	Regulator Location	Automation - Regulator Controllers	BOWNE Township	Customers Impacted	560
51	Grid Automation	REG26_FOURTEENTH STREET_LIPPINCOTT STREET	$27,052	1	Regulator Location	Automation - Regulator Controllers	FLINT	Customers Impacted	840
52	Grid Automation	REG26_LEVEL PARK_COLLIER	$27,052	1	Regulator Location	Automation - Regulator Controllers	BEDFORD Township	Customers Impacted	79
53	Grid Automation	REG26_LINCOLN_LOST LAKE	$54,104	2	Regulator Location	Automation - Regulator Controllers	GUSTIN Township	Customers Impacted	139
54	Grid Automation	REG26_LINCOLN_MIKADO	$135,260	5	Regulator Location	Automation - Regulator Controllers	GREENBUSH Township	Customers Impacted	527
55	Grid Automation	REG26_MILL GROVE_ALLEGAN HYDRO	$27,052	1	Regulator Location	Automation - Regulator Controllers	ALLEGAN Township	Customers Impacted	272
56	Grid Automation	REG26_MOLINE_MOLINE	$27,052	1	Regulator Location	Automation - Regulator Controllers	BYRON Township	Customers Impacted	548
57	Grid Automation	REG26_MORGAN_ORCHARD	$27,052	1	Regulator Location	Automation - Regulator Controllers	PENNFIELD Township	Customers Impacted	535
58	Grid Automation	REG26_MORGAN_ST MARYS	$135,260	5	Regulator Location	Automation - Regulator Controllers	PENNFIELD Township	Customers Impacted	1067
59	Grid Automation	REG26_NORTHERN FIBRE_FIBRE	$54,104	2	Regulator Location	Automation - Regulator Controllers	HOLLAND Township	Customers Impacted	916
60	Grid Automation	REG26_OLIVET_AINGER	$27,052	1	Regulator Location	Automation - Regulator Controllers	CARMEL Township	Customers Impacted	126
61	Grid Automation	REG26_OLIVET_COLLEGE	$54,104	2	Regulator Location	Automation - Regulator Controllers	UNION Township	Customers Impacted	259
62	Grid Automation	REG26_OSCODA_BUTLER HEIGHTS	$54,104	2	Regulator Location	Automation - Regulator Controllers	BALDWIN Township	Customers Impacted	864
63	Grid Automation	REG26_PULLMAN_CHICORA	$54,104	2	Regulator Location	Automation - Regulator Controllers	CLYDE Township	Customers Impacted	388
64	Grid Automation	REG26_PULLMAN_PULLMAN	$27,052	1	Regulator Location	Automation - Regulator Controllers	CLYDE Township	Customers Impacted	60
65	Grid Automation	REG26_SALEM_BURNIPS	$27,052	1	Regulator Location	Automation - Regulator Controllers	SALEM Township	Customers Impacted	303
66	Grid Automation	REG26_SHERMAN_SHERMAN	$27,052	1	Regulator Location	Automation - Regulator Controllers	GREENWOOD Township	Customers Impacted	92
67	Grid Automation	REG26_SPRUCE ROAD_BLACK RIVER	$27,052	1	Regulator Location	Automation - Regulator Controllers	CALEDONIA Township	Customers Impacted	368
68	Grid Automation	REG26_TAWAS_TAWAS	$81,156	3	Regulator Location	Automation - Regulator Controllers	TAWAS Township	Customers Impacted	803
69	Grid Automation	REG26_WAKESHMA_FULTON	$27,052	1	Regulator Location	Automation - Regulator Controllers	WAKESHMA Township	Customers Impacted	150
70	Grid Automation	REG26_WAKESHMA_LEONIDAS	$54,104	2	Regulator Location	Automation - Regulator Controllers	LEONIDAS Township	Customers Impacted	207
71	Grid Automation	REG26_WEBB ROAD_HALE	$27,052	1	Regulator Location	Automation - Regulator Controllers	PLAINFIELD Township	Customers Impacted	104
72	Grid Automation	REG26_WEST MAIN_CURWOOD	$27,052	1	Regulator Location	Automation - Regulator Controllers	MIDDLEBURY Township	Customers Impacted	267
73	Grid Automation	REG26_WILDER_WILDER	$27,052	1	Regulator Location	Automation - Regulator Controllers	ECKFORD Township	Customers Impacted	164
74	Grid Automation	REG26_WOODWARD_PLEASANT LAKE	$81,156	3	Regulator Location	Automation - Regulator Controllers	HARING Township	Customers Impacted	327
75	Grid Automation	REG26_WOODWARD_WOODWARD LAKE	$108,208	4	Regulator Location	Automation - Regulator Controllers	BOON Township	Customers Impacted	596
76	Grid Automation	REG26_WURTSMITH_MISSION	$27,052	1	Regulator Location	Automation - Regulator Controllers	UNION Township	Customers Impacted	216
77	Grid Automation	REG26_YORKVILLE_BATVIEW	$27,052	1	Regulator Location	Automation - Regulator Controllers	RICHLAND Township	Customers Impacted	157
78	Grid Automation	REG26_YORKVILLE_HIGHLAND PARK	$27,052	1	Regulator Location	Automation - Regulator Controllers	PRAIRIEVILLE Township	Customers Impacted	292
79	Grid Automation	REG26_AGNEW_WEYBURN	$27,052	1	Regulator Location	Automation - Regulator Controllers	GRAND HAVEN Township	Customers Impacted	1337
80	Grid Automation	REG26_ALLENDALE_RIVER	$27,052	1	Regulator Location	Automation - Regulator Controllers	CASCADE Township	Customers Impacted	434
81	Grid Automation	REG26_ATLAS_GALE	$27,052	1	Regulator Location	Automation - Regulator Controllers	ATLAS Township	Customers Impacted	1052
82	Grid Automation	REG26_BATH_BATH	$27,052	1	Regulator Location	Automation - Regulator Controllers	OLIVE Township	Customers Impacted	187
83	Grid Automation	REG26_BEAVERTON_TOBACCO	$27,052	1	Regulator Location	Automation - Regulator Controllers	BUCKEYE Township	Customers Impacted	186
84	Grid Automation	REG26_BEERS_SHARP	$27,052	1	Regulator Location	Automation - Regulator Controllers	GAINES Township	Customers Impacted	186
85	Grid Automation	REG26_BIRCH RUN_BIRCH RUN	$27,052	1	Regulator Location	Automation - Regulator Controllers	BIRCH RUN Township	Customers Impacted	96
86	Grid Automation	REG26_BRIDGEPORT_DIXIE	$27,052	1	Regulator Location	Automation - Regulator Controllers	BRIDGEPORT Township	Customers Impacted	140
87	Grid Automation	REG26_CALKINS_BEECHER ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	FLINT Township	Customers Impacted	648
88	Grid Automation	REG26_CALKINS_FLUSHING ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	FLINT Township	Customers Impacted	557
89	Grid Automation	REG26_CAMELOT LAKE_COLEMAN	$27,052	1	Regulator Location	Automation - Regulator Controllers	BEAVERTON Township	Customers Impacted	119
90	Grid Automation	REG26_CARROLLTON_MAPLE RIDGE	$27,052	1	Regulator Location	Automation - Regulator Controllers	CARROLLTON Township	Customers Impacted	487
91	Grid Automation	REG26_CLARE_FARWELL	$27,052	1	Regulator Location	Automation - Regulator Controllers	VERNON Township	Customers Impacted	229
92	Grid Automation	REG26_CLIO_MILL STREET	$81,156	3	Regulator Location	Automation - Regulator Controllers	VIENNA Township	Customers Impacted	534
93	Grid Automation	REG26_COOPER_COOPER CENTER	$54,104	2	Regulator Location	Automation - Regulator Controllers	COOPER Township	Customers Impacted	175
94	Grid Automation	REG26_COOPER_NAGEL	$27,052	1	Regulator Location	Automation - Regulator Controllers	COOPER Township	Customers Impacted	74
95	Grid Automation	REG26_COTTAGE GROVE_PREVO	$27,052	1	Regulator Location	Automation - Regulator Controllers	KAWKAWLIN Township	Customers Impacted	374
96	Grid Automation	REG26_CURTIS_MAGRUDDER	$27,052	1	Regulator Location	Automation - Regulator Controllers	TOBACCO Township	Customers Impacted	21
97	Grid Automation	REG26_DIXIE_BRANCH ROAD	$54,104	2	Regulator Location	Automation - Regulator Controllers	GENESEE Township	Customers Impacted	710
98	Grid Automation	REG26_DUFFIELD_DUFFIELD	$27,052	1	Regulator Location	Automation - Regulator Controllers	GAINES Township	Customers Impacted	78
99	Grid Automation	REG26_DURAND_CITY	$27,052	1	Regulator Location	Automation - Regulator Controllers	OGDEN Township	Customers Impacted	600
100	Grid Automation	REG26_EAST GENESEE AVE_OUTER DRIVE	$27,052	1	Regulator Location	Automation - Regulator Controllers	BUENA VISTA Township	Customers Impacted	15
101	Grid Automation	REG26_EAST GRANT_MUD FLAT	$27,052	1	Regulator Location	Automation - Regulator Controllers	ENSLEY Township	Customers Impacted	156
102	Grid Automation	REG26_ELLIS_LAKES MALL	$27,052	1	Regulator Location	Automation - Regulator Controllers	FRUITPORT Township	Customers Impacted	215
103	Grid Automation	REG26_ELSIE_BANNISTER	$54,104	2	Regulator Location	Automation - Regulator Controllers	RUSH Township	Customers Impacted	121
104	Grid Automation	REG26_FAIRFIELD_JASPER	$27,052	1	Regulator Location	Automation - Regulator Controllers	MADISON Township	Customers Impacted	43
105	Grid Automation	REG26_FISH LAKE_ROSE	$27,052	1	Regulator Location	Automation - Regulator Controllers	ROSE Township	Customers Impacted	684
106	Grid Automation	REG26_GIRARD_DAYBURG ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	COLDWATER Township	Customers Impacted	128
107	Grid Automation	REG26_GREGORY_UNADILLA	$27,052	1	Regulator Location	Automation - Regulator Controllers	UNADILLA Township	Customers Impacted	137
108	Grid Automation	REG26_GULL LAKE_TURNER	$27,052	1	Regulator Location	Automation - Regulator Controllers	BARRY Township	Customers Impacted	100
109	Grid Automation	REG26_HENDERSHOT_CENTENNIAL	$27,052	1	Regulator Location	Automation - Regulator Controllers	RAISIN Township	Customers Impacted	14
110	Grid Automation	REG26_HESPERIA_RURAL	$27,052	1	Regulator Location	Automation - Regulator Controllers	SEVILLE Township	Customers Impacted	505
111	Grid Automation	REG26_HILL ROAD_WALKABOUT	$27,052	1	Regulator Location	Automation - Regulator Controllers	MUNDY Township	Customers Impacted	357
112	Grid Automation	REG26_HOGAN ROAD_HOISINGTON	$27,052	1	Regulator Location	Automation - Regulator Controllers	FENTON Township	Customers Impacted	265
113	Grid Automation	REG26_HOLTON_HOLTON	$27,052	1	Regulator Location	Automation - Regulator Controllers	HOLTON Township	Customers Impacted	404
114	Grid Automation	REG26_HUBBARDSTON ROAD_STONEY CREEK	$27,052	1	Regulator Location	Automation - Regulator Controllers	DALLAS Township	Customers Impacted	63
115	Grid Automation	REG26_KAWKAWLIN_LAGOON BEACH	$27,052	1	Regulator Location	Automation - Regulator Controllers	BANGOR Township	Customers Impacted	876
116	Grid Automation	REG26_KAWKAWLIN_WHEELER ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	BANGOR Township	Customers Impacted	176
117	Grid Automation	REG26_KNIGHT_ROSEMARY	$27,052	1	Regulator Location	Automation - Regulator Controllers	PORTSMOUTH Township	Customers Impacted	1494
118	Grid Automation	REG26_LAINGSBURG_LELAND ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	VICTOR Township	Customers Impacted	209
119	Grid Automation	REG26_LARKIN_N MIDLAND	$27,052	1	Regulator Location	Automation - Regulator Controllers	LINCOLN Township	Customers Impacted	621
120	Grid Automation	REG26_LEHRING_COLE ROAD	$54,104	2	Regulator Location	Automation - Regulator Controllers	BURNS Township	Customers Impacted	251
121	Grid Automation	REG26_LEHRING_MYERS LAKE	$162,312	6	Regulator Location	Automation - Regulator Controllers	ARGENTINE Township	Customers Impacted	933
122	Grid Automation	REG26_LENNON ROAD_SHOPPERS	$27,052	1	Regulator Location	Automation - Regulator Controllers	FLINT Township	Customers Impacted	238
123	Grid Automation	REG26_LESLIE_BUSINESS	$27,052	1	Regulator Location	Automation - Regulator Controllers	UNION Township	Customers Impacted	145
124	Grid Automation	REG26_LEVELY_ALLBRIGHT	$27,052	1	Regulator Location	Automation - Regulator Controllers	BUCKEYE Township	Customers Impacted	311
125	Grid Automation	REG26_LEVELY_STURGEON	$108,208	4	Regulator Location	Automation - Regulator Controllers	TOBACCO Township	Customers Impacted	655
126	Grid Automation	REG26_LINDEN_NORTH LINDEN	$27,052	1	Regulator Location	Automation - Regulator Controllers	FENTON Township	Customers Impacted	782
127	Grid Automation	REG26_LITCHFIELD_QUAKER LAKE	$27,052	1	Regulator Location	Automation - Regulator Controllers	CLARENDON Township	Customers Impacted	56
128	Grid Automation	REG26_MAGNUS_MCKAY FARM	$27,052	1	Regulator Location	Automation - Regulator Controllers	SURREY Township	Customers Impacted	519
129	Grid Automation	REG26_MCCANDLISH_THREAD RIVER	$27,052	1	Regulator Location	Automation - Regulator Controllers	ATLAS Township	Customers Impacted	257
130	Grid Automation	REG26_MCGRAW_PORTSMOUTH	$27,052	1	Regulator Location	Automation - Regulator Controllers	PORTSMOUTH Township	Customers Impacted	556
131	Grid Automation	REG26_MONTROSE_MCKINLEY ROAD	$54,104	2	Regulator Location	Automation - Regulator Controllers	VIENNA Township	Customers Impacted	383
132	Grid Automation	REG26_MORRICE_M-78	$27,052	1	Regulator Location	Automation - Regulator Controllers	ONEIDA Township	Customers Impacted	166
133	Grid Automation	REG26_MORRICE_SOUTH MORRICE	$27,052	1	Regulator Location	Automation - Regulator Controllers	BURNS Township	Customers Impacted	347
134	Grid Automation	REG26_MT FOREST_BENTLEY	$135,260	5	Regulator Location	Automation - Regulator Controllers	GRIM Township	Customers Impacted	553
135	Grid Automation	REG26_MT FOREST_MT FOREST	$108,208	4	Regulator Location	Automation - Regulator Controllers	LINCOLN Township	Customers Impacted	496
136	Grid Automation	REG26_NEFF ROAD_DODGE ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	VIENNA Township	Customers Impacted	232
137	Grid Automation	REG26_NESTROM_SCENIC DRIVE	$54,104	2	Regulator Location	Automation - Regulator Controllers	LAKETON Township	Customers Impacted	863
138	Grid Automation	REG26_NEW HAVEN_JUDDVILLE	$27,052	1	Regulator Location	Automation - Regulator Controllers	BRADY Township	Customers Impacted	370
139	Grid Automation	REG26_NEW LOTHROP_BYRON ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	MAPLE GROVE Township	Customers Impacted	60
140	Grid Automation	REG26_NORTH MUSKEGON_STATE PARK	$54,104	2	Regulator Location	Automation - Regulator Controllers	BANGOR Township	Customers Impacted	860
141	Grid Automation	REG26_OAK STREET_COOPER STREET	$27,052	1	Regulator Location	Automation - Regulator Controllers	BLACKMAN Township	Customers Impacted	106
142	Grid Automation	REG26_OSHTEMO_ALMENA	$27,052	1	Regulator Location	Automation - Regulator Controllers	OSHTEMO Township	Customers Impacted	567
143	Grid Automation	REG26_OTISVILLE_IRISH ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	FOREST Township	Customers Impacted	98
144	Grid Automation	REG26_OTISVILLE_STATE ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	FOREST Township	Customers Impacted	191
145	Grid Automation	REG26_OWOSSO_GOULD	$27,052	1	Regulator Location	Automation - Regulator Controllers	CALEDONIA Township	Customers Impacted	717
146	Grid Automation	REG26_PINCONNING_WHITE FEATHER	$27,052	1	Regulator Location	Automation - Regulator Controllers	LINCOLN Township	Customers Impacted	95
147	Grid Automation	REG26_PORTAGE_SHAVER ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	SCHOOLCRAFT Township	Customers Impacted	1183
148	Grid Automation	REG26_PORTER_PARTS	$27,052	1	Regulator Location	Automation - Regulator Controllers	GRAND BLANC Township	Customers Impacted	318
149	Grid Automation	REG26_PRICE ROAD_PRICE	$27,052	1	Regulator Location	Automation - Regulator Controllers	LINCOLN Township	Customers Impacted	257
150	Grid Automation	REG26_ROTHBURY_NEW ERA	$27,052	1	Regulator Location	Automation - Regulator Controllers	BENONA Township	Customers Impacted	465
151	Grid Automation	REG26_RUSSELLVILLE_RICHFIELD	$27,052	1	Regulator Location	Automation - Regulator Controllers	RICHFIELD Township	Customers Impacted	305
152	Grid Automation	REG26_RUSSELLVILLE_VASSAR ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	GENESEE Township	Customers Impacted	152
153	Grid Automation	REG26_RUSSELLVILLE_VICTORIA	$54,104	2	Regulator Location	Automation - Regulator Controllers	RICHFIELD Township	Customers Impacted	1025
154	Grid Automation	REG26_SALZBURG_SALZBURG	$54,104	2	Regulator Location	Automation - Regulator Controllers	BANGOR Township	Customers Impacted	128
155	Grid Automation	REG26_SEVEN MILE_MAIDA	$27,052	1	Regulator Location	Automation - Regulator Controllers	PINCONNING Township	Customers Impacted	70
156	Grid Automation	REG26_SEVEN MILE_QUARTERLINE	$27,052	1	Regulator Location	Automation - Regulator Controllers	BROOKS Township	Customers Impacted	113
157	Grid Automation	REG26_SKYLARK_HILL	$27,052	1	Regulator Location	Automation - Regulator Controllers	GRAND BLANC Township	Customers Impacted	979
158	Grid Automation	REG26_SKYLARK_ROCKING CHAIR	$27,052	1	Regulator Location	Automation - Regulator Controllers	GRAND BLANC Township	Customers Impacted	997
159	Grid Automation	REG26_SKYLARK_SUN VALLEY	$27,052	1	Regulator Location	Automation - Regulator Controllers	ATLAS Township	Customers Impacted	1016
160	Grid Automation	REG26_SPRING ARBOR_CHAPEL	$27,052	1	Regulator Location	Automation - Regulator Controllers	SPRING ARBOR Township	Customers Impacted	122
161	Grid Automation	REG26_SPRING DRIVE_BISHOP LAKE	$27,052	1	Regulator Location	Automation - Regulator Controllers	SHERMAN Township	Customers Impacted	825
162	Grid Automation	REG26_SQUIRE HILL_EDGEWATER	$27,052	1	Regulator Location	Automation - Regulator Controllers	FLINT Township	Customers Impacted	1230
163	Grid Automation	REG26_ST CHARLES_FERGUS	$27,052	1	Regulator Location	Automation - Regulator Controllers	ALBEE Township	Customers Impacted	116
164	Grid Automation	REG26_STEEL DRIVE_VISTA	$27,052	1	Regulator Location	Automation - Regulator Controllers	TYRONE Township	Customers Impacted	663
165	Grid Automation	REG26_SWARTZ CREEK_MORRISH ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	GAINES Township	Customers Impacted	1003
166	Grid Automation	REG26_THOMAS_THOMAS	$27,052	1	Regulator Location	Automation - Regulator Controllers	THOMAS Township	Customers Impacted	79
167	Grid Automation	REG26_TINSMAN_FISH LAKE ROAD	$27,052	1	Regulator Location	Automation - Regulator Controllers	HOLLY Township	Customers Impacted	118
168	Grid Automation	REG26_TOWN LINE_FRASER	$27,052	1	Regulator Location	Automation - Regulator Controllers	MONITOR Township	Customers Impacted	248
169	Grid Automation	REG26_TOWN LINE_MACKINAW	$27,052	1	Regulator Location	Automation - Regulator Controllers	KAWKAWLIN Township	Customers Impacted	57
170	Grid Automation	REG26_WALDO_LABORATORY	$27,052	1	Regulator Location	Automation - Regulator Controllers	DEWITT Township	Customers Impacted	834
171	Grid Automation	REG26_WAMPLERS_FRANKLIN	$27,052	1	Regulator Location	Automation - Regulator Controllers	MANCHESTER Township	Customers Impacted	241
172	Grid Automation	REG26_WARNER_MILO	$27,052	1	Regulator Location	Automation - Regulator Controllers	PRAIRIEVILLE Township	Customers Impacted	838
173	Grid Automation	REG26_WHITE CLOUD_WILLIAM STREET	$27,052	1	Regulator Location	Automation - Regulator Controllers	SHERMAN Township	Customers Impacted	277
174	Grid Automation	REG26_WINGATE_NORTH	$27,052	1	Regulator Location	Automation - Regulator Controllers	FREEDOM Township	Customers Impacted	177
175	Grid Automation	REG26_WINGATE_SOUTH	$27,052	1	Regulator Location	Automation - Regulator Controllers	JOHNSTOWN Township	Customers Impacted	162
			$6,276,064	232					

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Voltage Regulator Controller Inventory Record

Case No.: U-22070
Exhibit No.: A-162 (SAM-5)
Page: 1 of 1
Witness: SAMcPhail
Date: June 2026

Line No.	(a)	(b)	(c)
1	**Assessment Activity**	**# of Multiphase Controls**	**# of Single Phase Controls**
2	**# of Regulator Controllers Available for final Year (2026) of Deployment**	185	66
3	**# of Regulator Controllers in Inventory as of 4/1/2026**	141	57
4	**# of Regulator Controllers Installed between 1/1/2026 and 4/1/2026**	44	9
5	**Estimated # of Regulator Controllers left to be Installed after 4/1/2026**	127	45
6	**Estimated # overall Regulator Controllers to be installed during the 2026 Deployment Year**	171	54
7	**Estimated # Regulator Controllers Leftover at 2026 Year End**	14	12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Metro Modernization Reliability Benefits

Case No.: U-22070
Exhibit No.: A-163 (SAM-6)
Page: 1 of 5
Witness: SAMcPhail
Date: June 2026

Line No.	(a)	(b)	
1	**Reliability Benefits**	**1,062,438**	**Avoided CMI**
2	**Rate Recovery Costs**	**$ 44,496,963**	

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

1889301	**customer population**
60	**average time to visit a site with a crew going into enclosed spaces**
157	**number of vaults today**

Benefits Calculations

Reduce patrol time via not having to check so many device locations in manholes to **validate the state of the system** and location of the fault.

5	average number of switching and tagging points during an incident to validate
60	average length of time to validate a site
300	minutes to validate the state of the system before restoration
30	projected validation minutes in new state
270	minutes of validation saved
1561	customer affected annually
421470	saved customer minutes
0.222	**SAIDI**
0.0014	SAIDI per vault

		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
SAIDI	**Sum**	0.0000	0.0028	0.0099	0.0170	0.0240	0.0311	0.0381	0.0452	0.0523	0.0593	0.0664	0.0735

Remote Restoration

this is at the end of each outage incident that we can avoid returning to the open vault/circuit situation because it can be closed in remotely.

1,561	customer affected annually
60	average time it takes to set up for restoration which is being eliminated
93,660	annual minutes saved due to remote restoration
596.56	minutes saved per vault

		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
SAIDI	**Sum**	0.0000	0.0006	0.0022	0.0038	0.0054	0.0069	0.0085	0.0101	0.0117	0.0133	0.0148	0.0164

Planned Transfers < instead of sending crews to multiple vaults, execute return to normal switching steps remotely without crew involvement

5	average number of switching and tagging points in a switching order
60	average length of time to validate a site
50	number of switching orders executed in a year
15	time it takes in new state
237.5	saved crew hours per switching order

Public safety/security:

high water alarms to avoid flooding vaults which dump all customers.

historical flooding outage data:

		cust average	min	custmin	
2024	1	87	313	27231	
2021	2	460.5		191000	
2019	3			26112	
				48869	annual flooding outage minutes avoided due to high water sensors/alarms
				311	per vault

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
SAIDI	0.00000	0.00033	0.00115	0.00198	0.00280	0.00362	0.00445	0.00527	0.00610	0.00692	0.00774	0.00857

Safety how many people hours of exposure is being eliminated

24	number of outage incidents in 2024
370	number of switching times a vault would be visited
15	average time at a site spent doing the hazardous work associated with entering vaults
2	average number of persons in a crew
185	total people hours of exposure to vaults by crews eliminated
1.18	people hours of exposure per vault

exposure	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
hours	0.0	2.4	8.2	14.1	20.0	25.9	31.8	37.7	43.6	49.5	55.4	61.3

Timeline	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Vault Deployment Forecast	0	2	5	5	5	5	5	5	5	5	5	5
Vault Investment by Year ($)		$ 844,133	$ 2,110,333	$ 2,110,333	$ 2,110,333	$ 2,110,333	$ 2,110,333	$ 2,110,333	$ 2,110,333	$ 2,110,333	$ 2,110,333	$ 2,110,333

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Metro Modernization Reliability Benefits

Case No.: U-22070
Exhibit No.: A-163 (SAM-6)
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CAPITAL SPENDING ($000)
Project Name: Metro Modernization

Note: Capital Spending entered below should include any AFUDC. If a project was started in 2025 or before the total spend to date related to the project should be entered into the Balance as of 12/31/2025 (including any AFUDC).

Cost

Line Item	Schedule B-5 Category (Drop Down Menu)	Look-Up on B-5 Composite Deprecation Rate	Expected COD	Balance as of (12/31/2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1	Distribution	2.98%	2027	-	-	844	2,110	2,110	2,110	2,110	2,110	2,110	2,110	2,110	2,110	2,110	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Distribution	2.98%	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution	2.98%	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	2.98%	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Distribution	2.98%	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Distribution	2.98%	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	2.98%	2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Is Project AFUDC Eligible No

O&M Expense ($000)

Line Item	Description		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Benefits

Line Item	Schedule B-5 Category (Drop Down Menu)	Look-Up on B-5 Composite Deprecation Rate	Expected COD	Balance as of (12/31/2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Is Project AFUDC Eligible No

O&M Expense ($000)

Line Item	Description		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TO BE UPATED BY REVENUE REQUIREMENTS:

Per 2025 Historical - See Plant Model	
Depreciation Rate Table	
Distribution	2.98%
Production (Hydro)	19.76%
Production (Hydro Ludingto	2.77%
Production (Steam)	4.11%
Production (Battery)	6.91%
Production (Other)	2.47%
Intangibles	20.00%
E-GP Structures	2.56%
E-GP Computers	20.00%
E-GP Transportation	1.24%
E-GP Other	5.42%
C-GP Structures	1.56%
C-GP Computers	20.00%
C-GP Transportation	0.53%
C-GP Other	5.17%
Production Acq Adjustment	3.45%
N/A - Line Not Used	

Pre-tax return (approved in U-21870)	7.54%
R&PP Tax (U-21870 Exh A-161 (BJV-1))	1.33%

Yes
No

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Metro Modernization Reliability Benefits

Case No.: U-22070
Exhibit No.: A-163 (SAM-6)
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Witness: SAMcPhail
Date: June 2026

	Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Cost		**Plant In Service**																														
	1	Distribution Average Plant In Service	$ -	$ 422	$ 1,899	$ 4,010	$ 6,120	$ 8,230	$ 10,341	$ 12,451	$ 14,561	$ 16,672	$ 18,782	$ 20,892	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947	$ 21,947
	2	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	4	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	5	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	6	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	7	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	8	**Total Average Plant in Service**	**$ -**	**$ 422**	**$ 1,899**	**$ 4,010**	**$ 6,120**	**$ 8,230**	**$ 10,341**	**$ 12,451**	**$ 14,561**	**$ 16,672**	**$ 18,782**	**$ 20,892**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**	**$ 21,947**
		Accumulated Deprecation Reserve																														
	9	Beginning Depreciation Reserve	$ -	$ -	$ 6	$ 63	$ 182	$ 364	$ 609	$ 917	$ 1,288	$ 1,721	$ 2,217	$ 2,776	$ 3,398	$ 4,052	$ 4,705	$ 5,358	$ 6,011	$ 6,665	$ 7,318	$ 7,971	$ 8,625	$ 9,278	$ 9,931	$ 10,584	$ 11,238	$ 11,891	$ 12,544	$ 13,198	$ 13,851	$ 14,504
	10	Deprecation Expense - Distribution	0	6	57	119	182	245	308	371	433	496	559	622	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653
	11	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	17	End Depreciation Reserve	$ -	$ 6	$ 63	$ 182	$ 364	$ 609	$ 917	$ 1,288	$ 1,721	$ 2,217	$ 2,776	$ 3,398	$ 4,052	$ 4,705	$ 5,358	$ 6,011	$ 6,665	$ 7,318	$ 7,971	$ 8,625	$ 9,278	$ 9,931	$ 10,584	$ 11,238	$ 11,891	$ 12,544	$ 13,198	$ 13,851	$ 14,504	$ 15,157
	18	**Average Depreciation Reserve**	**$ -**	**$ 3**	**$ 35**	**$ 122**	**$ 273**	**$ 487**	**$ 763**	**$ 1,102**	**$ 1,504**	**$ 1,969**	**$ 2,497**	**$ 3,087**	**$ 3,725**	**$ 4,378**	**$ 5,032**	**$ 5,685**	**$ 6,338**	**$ 6,991**	**$ 7,645**	**$ 8,298**	**$ 8,951**	**$ 9,605**	**$ 10,258**	**$ 10,911**	**$ 11,564**	**$ 12,218**	**$ 12,871**	**$ 13,524**	**$ 14,178**	**$ 14,831**
	19	**Total Average Rate Base**	**$ -**	**$ 419**	**$ 1,865**	**$ 3,887**	**$ 5,847**	**$ 7,743**	**$ 9,577**	**$ 11,349**	**$ 13,057**	**$ 14,702**	**$ 16,285**	**$ 17,805**	**$ 18,222**	**$ 17,569**	**$ 16,916**	**$ 16,263**	**$ 15,609**	**$ 14,956**	**$ 14,303**	**$ 13,649**	**$ 12,996**	**$ 12,343**	**$ 11,690**	**$ 11,036**	**$ 10,383**	**$ 9,730**	**$ 9,076**	**$ 8,423**	**$ 7,770**	**$ 7,117**
Benefit		**Plant In Service**																														
	20	Distribution Average Plant In Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	21	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	22	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	23	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	24	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	26	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	27	**Total Average Plant in Service**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
		Accumulated Deprecation Reserve																														
	28	Beginning Depreciation Reserve	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	29	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	30	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	31	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	32	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	33	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	34	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	35	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	36	End Depreciation Reserve	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	37	**Average Depreciation Reserve**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	38	**Total Average Rate Base**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Metro Modernization Reliability Benefits

Case No.: U-22070
Exhibit No.: A-163 (SAM-6)
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Witness: SAMcPhail
Date: June 2026

Cost

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ -	$ 419	$ 1,865	$ 3,887	$ 5,847	$ 7,743	$ 9,577	$ 11,349	$ 13,057	$ 14,702	$ 16,285	$ 17,805	$ 18,222	$ 17,569	$ 16,916	$ 16,263	$ 15,609	$ 14,956	$ 14,303	$ 13,649	$ 12,996	$ 12,343	$ 11,690	$ 11,036	$ 10,383	$ 9,730	$ 9,076	$ 8,423	$ 7,770	$ 7,117	
2	Total Return on Investment	$ -	$ 32	$ 141	$ 293	$ 441	$ 584	$ 722	$ 856	$ 984	$ 1,109	$ 1,228	$ 1,342	$ 1,374	$ 1,325	$ 1,275	$ 1,226	$ 1,177	$ 1,128	$ 1,078	$ 1,029	$ 980	$ 931	$ 881	$ 832	$ 783	$ 734	$ 684	$ 635	$ 586	$ 537	**$ 24,926**
3	Total Depreciation Expense	-	6	57	119	182	245	308	371	433	496	559	622	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	**15,157**
4	Total R&PP Tax	-	6	25	52	78	103	128	151	174	196	217	238	243	235	226	217	208	200	191	182	173	165	156	147	139	130	121	112	104	95	**4,413**
5	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Revenue Requirement	$ -	$ 43	$ 222	$ 464	$ 701	$ 932	$ 1,158	$ 1,378	$ 1,592	$ 1,801	$ 2,004	$ 2,202	$ 2,271	$ 2,213	$ 2,155	$ 2,097	$ 2,039	$ 1,981	$ 1,923	$ 1,865	$ 1,807	$ 1,749	$ 1,691	$ 1,633	$ 1,575	$ 1,517	$ 1,459	$ 1,401	$ 1,343	$ 1,285	**$ 44,497**

Benefit

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
7	Total Return on Investment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
8	Total Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total R&PP Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Total Revenue Requirement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**

Net Cost (Benefit)

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ -	$ 419	$ 1,865	$ 3,887	$ 5,847	$ 7,743	$ 9,577	$ 11,349	$ 13,057	$ 14,702	$ 16,285	$ 17,805	$ 18,222	$ 17,569	$ 16,916	$ 16,263	$ 15,609	$ 14,956	$ 14,303	$ 13,649	$ 12,996	$ 12,343	$ 11,690	$ 11,036	$ 10,383	$ 9,730	$ 9,076	$ 8,423	$ 7,770	$ 7,117	
12	Total Return on Investment	-	32	141	293	441	584	722	856	984	1,109	1,228	1,342	1,374	1,325	1,275	1,226	1,177	1,128	1,078	1,029	980	931	881	832	783	734	684	635	586	537	**$ 24,926**
13	Total Depreciation Expense	-	6	57	119	182	245	308	371	433	496	559	622	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	**15,157**
14	Total R&PP Tax	-	6	25	52	78	103	128	151	174	196	217	238	243	235	226	217	208	200	191	182	173	165	156	147	139	130	121	112	104	95	**4,413**
15	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Total Revenue Requirement	$ -	$ 43	$ 222	$ 464	$ 701	$ 932	$ 1,158	$ 1,378	$ 1,592	$ 1,801	$ 2,004	$ 2,202	$ 2,271	$ 2,213	$ 2,155	$ 2,097	$ 2,039	$ 1,981	$ 1,923	$ 1,865	$ 1,807	$ 1,749	$ 1,691	$ 1,633	$ 1,575	$ 1,517	$ 1,459	$ 1,401	$ 1,343	$ 1,285	**$ 44,497**

Footnotes:
Pre-tax return 7.54%
R&PP Tax 1.33%

Line No.	(a)	(b)	
1	**Total Benefits**	**$**	**17,764,242**
2	**Total Costs**	**$**	**17,180,152**
3	**NPV**	**$**	**584,091**
4	**Rate Recovery Costs**	**$**	**42,385,239**
5	**Rate Recovery Benefits**	**$**	**56,261,299**
6	**Net Rate Recovery**	**$**	**13,876,060**

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

	1,889,301	Total Electric Customers
$	440.00	Typical 3 person Elec Dist Crew $/hour (loaded costs)
	15%	Distribution Asset Management Year to Year Improvement %
	5%	Asset Data Quality Beginning Perecentage
	36%	Asset Management System (AMS) maturity %
	3%	Asset Depreciation Improvement value
	85%	% Work Assignned to CE Crews
	15%	% Work Assignned to Contract Crews
$	955.00	Contractor Crew Cost $/hour (direct cost)

	2,295	Five Year Average of Annual Outages per feeder
$	357.29	Average O&M Spend per outage on Feeder
	40%	Avoided Restoration Costs Loading Multiplier
	31%	Overtime %.
	105%	Maturity Cost Adder.
	23,267	Medium & Large C&I customer count

Benefits Calculations

Benefit Calculations are summarized in the "Benefits & Costs Data" worksheet.
The "Benefit Details" worksheet describes the different project impacts on the E
The "Asset Details" worksheet includes asset specific benefit ca
The "Avoided Restoration Costs" worksheet is used to show a multi-year breakdown of avoided restoration c

Monetized Benefits($): *(yearly values in thousands)*

$ 17,764,242	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Tota per Year	$ -	$ 129	$ 628	$ 1,542	$ 2,980	$ 4,147	$ 5,483	$ 6,584	$ 7,570

Costs Calculations

WACC **7.25%**

Capital Spend ($): *(yearly values in thousands)*

$ 17,180,152	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Total per Year	$ 3,331	$ 2,506	$ 10,254	$ 1,804	$ 1,804	$ 400	$ 400	$ 400	$ 400

Line No.				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Total of all Costs**			$ 3,331	$ 2,506	$ 10,254	$ 1,804	$ 1,804	$ 400	$ 400	$ 400	$ 400
2												
3	**Asset Repository (AR)**			**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
4	Asset Count Project Scope			20	20	20	20	20	20	20	20	20
5	Planned Yearly Assets			7	6	6	1	0	0	0	0	0
6	Planned Assets Cumulative			7	13	19	20	20	20	20	20	20
7	Asset Percentage			35%	65%	95%	100%	100%	100%	100%	100%	100%
8		Months		12	12	12	3					
9	DICE			$ 700								
10	AR Cost	IT	90	$ 1,080	$ 1,080	$ 1,080	$ 270	$ -	$ -	$ -	$ -	$ -
11	Overheads			$ 1,024	$ 324	$ 324	$ 81					
12				$ 2,804	$ 1,404	$ 1,404	$ 351					
13												
14	**Asset Performance Management (APM)**			**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
15	Asset Count Project Scope			20	20	20	20	20	20	20	20	20
16	Planned Yearly Assets			2	5	13	0	0	0	0	0	0
17	Planned Assets Cumulative			2	7	20	20	20	20	20	20	20
18	Asset Percentage			10%	35%	100%	100%	100%	100%	100%	100%	100%
19		Months		9	12	12	12	3				
20	APM Cost	IT	45	$ 405	$ 540	$ 6,500	$ -	$ -	$ -	$ -	$ -	$ -
21	Overheads			$ 122	$ 162	$ 1,950	$ -	$ -				
22	Total			$ 527	$ 702	$ 8,450	$ -	$ -				
23												
24	**Asset Investment Planning (AIP)**			**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
25	Asset Count Project Scope			20	20	20	20	20	20	20	20	20
26	Planned Yearly Assets			2	5	6	6	1	0	0	0	0
27	Planned Assets Cumulative			2	7	13	19	20	20	20	20	20
28	Asset Percentage			10%	35%	65%	95%	100%	100%	100%	100%	100%
29												
30	**Device Management (DM)**			**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
31	Asset Count Project Scope			20	20	20	20	20	20	20	20	20
32	Planned Yearly Assets			2	5	6	6	1	0	0	0	0
33	Planned Assets Cumulative			2	7	13	19	20	20	20	20	20
34	Asset Percentage			10%	35%	65%	95%	100%	100%	100%	100%	100%
35		Months		0	0	0	9	12				
36	DM Cost	IT	90	$ -	$ -	$ -	$ 810	$ 1,080	$ -	$ -	$ -	$ -
37	Overheads			$ -	$ -	$ -	$ 243	$ 324				
38	Total			$ -	$ -	$ -	$ 1,053	$ 1,404				
39												
40	**DistAM Asset Management System (AMS)**			**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
41	AMS Team				$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400

Asset Repository (AR)					**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
	Asset Count Project Scope				20	20	20	20	20	20	20	20	20
	Planned Yearly Assets				7	6	6	1	0	0	0	0	0
	Planned Assets Cumulative				7	13	19	20	20	20	20	20	20
	AR Asset Coverage				35%	65%	95%	100%	100%	100%	100%	100%	100%
	Asset Data Quality Percentage		**Improvement/Year =>**	15%	5%	6%	7%	8%	9%	10%	12%	13%	15%
	AR Effective Percentage				2%	4%	6%	8%	9%	10%	12%	13%	15%

Asset Performance Management (APM)					**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
	Asset Count Project Scope				20	20	20	20	20	20	20	20	20
	Planned Yearly Assets				2	5	6	6	1	0	0	0	0
	Planned Assets Cumulative				2	7	13	19	20	20	20	20	20
	APM Asset Health Coverage				10%	35%	65%	95%	100%	100%	100%	100%	100%
	Asset Data Quality Percentage	**Same values as AR**	**Improvement/Year =>**	15%	5%	6%	7%	8%	9%	10%	12%	13%	15%
	APM Effective Percentage				1%	2%	4%	7%	9%	10%	12%	13%	15%

Asset Investment Planning (AIP)				**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
	AIP Implementation	AIP Implemented Jun/2025		100%	100%	100%	100%	100%	100%	100%	100%	100%

Device Management (DM)				**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
	DM Implementation			0%	0%	0%	25%	100%	100%	100%	100%	100%

DistAM Asset Project				**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Asset Management System (AMS) Maturity Level	Industry expert Assessment => 36%	**Improvement/Year =>**	15%	36%	41%	48%	55%	63%	72%	83%	96%	100%
DistAM Maturity Level (AR x APM x AIP)				0.009%	1.3%	4.1%	7.2%	8.7%	10.1%	11.6%	13.3%	15.3%
Overall DistAM Effectiveness (AMS Maturity x DistAM)				0.003%	0.5%	1.9%	4.0%	5.5%	7.3%	9.6%	12.7%	15.3%

Reduced Avoided Capital Costs	**Distribution Capacity. Annual Deferred Savings. Depreciation**	Customer Outage Reduction	$ -	$ 82,098	$ 400,012	$ 982,459	$ 1,898,979	$ 2,643,579	$ 3,496,133	$ 4,198,541	$ 4,828,322
Reduced Avoided O&M Costs	**Distribution: O&M. Avoided O&M from Reduced Failures**		$ -	$ 4,130	$ 20,125	$ 49,428	$ 95,539	$ 133,000	$ 175,892	$ 211,231	$ 242,915
Avoided Restoration Costs	**Electric Utility: Reliability. Reliability Value from Outages Avoided**		$ -	$ 372	$ 1,541	$ 3,217	$ 5,286	$ 6,255	$ 7,031	$ 7,177	$ 7,016
Improved Power Quality	**Societal Impacts. Customer Risk. Improved Power Quality**	Customer Improvement in Quality	$ -	$ 9,271	$ 45,170	$ 110,941	$ 214,436	$ 298,517	$ 394,789	$ 474,106	$ 545,222
Reliability Degradation Risk	**Electric Utility: Risk. Reliability Value from Degradation Risk**		$ -	$ 33,100	$ 161,273	$ 396,098	$ 765,612	$ 1,065,813	$ 1,409,538	$ 1,692,728	$ 1,946,637
	Total Benefits		$ -	$ 128,971	$ 628,121	$ 1,542,143	$ 2,979,852	$ 4,147,164	$ 5,483,383	$ 6,583,783	$ 7,570,113

CAPITAL SPENDING ($000)
Project Name: Distribution Asset Management

Note: Capital Spending entered below should include any AFUDC. If a project was started in 2025 or before the total spend to date related to the project should be entered into the Balance as of 12/31/2025 (including any AFUDC).

Cost

Line Item	Schedule B-5 Category (Drop Down Menu)	Look-Up on B-5 Composite Deprecation Rate	Expected COD	Balance as of (12/31/2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1	Distribution	2.98%	2028	-	2,506	10,254	1,804	1,804	400	400	400	400	400	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Is Project AFUDC Eligible No

O&M Expense ($000)

Line Item	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1																															

Benefits

Line Item	Schedule B-5 Category (Drop Down Menu)	Look-Up on B-5 Composite Deprecation Rate	Expected COD	Balance as of (12/31/2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1	Distribution	2.98%	2029	-	-	115	561	1,379	2,665	3,709	4,906	5,891	6,775	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Is Project AFUDC Eligible No

O&M Expense ($000)

Line Item	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1		-	14	67	164	315	438	578	693	795	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TO BE UPATED BY REVENUE REQUIREMENTS:

Per 2025 Historical - See Plant Model	
Depreciation Rate Table	
Distribution	2.98%
Production (Hydro)	19.76%
Production (Hydro Ludingto	2.77%
Production (Steam)	4.11%
Production (Battery)	6.91%
Production (Other)	2.47%
Intangibles	20.00%
E-GP Structures	2.56%
E-GP Computers	20.00%
E-GP Transportation	1.24%
E-GP Other	5.42%
C-GP Structures	1.56%
C-GP Computers	20.00%
C-GP Transportation	0.53%
C-GP Other	5.17%
Production Acq Adjustment	3.45%
N/A - Line Not Used	

Pre-tax return (approved in U-21870)	7.54%
R&PP Tax (U-21870 Exh A-161 (BJV-1))	1.33%

Yes
No

	Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Cost		**Plant In Service**																														
	1	Distribution Average Plant In Service	$ 1,253	$ 7,633	$ 13,662	$ 15,466	$ 16,568	$ 16,968	$ 17,368	$ 17,768	$ 18,168	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368
	2	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	4	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	5	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	6	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	7	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	8	**Total Average Plant in Service**	**$ 1,253**	**$ 7,633**	**$ 13,662**	**$ 15,466**	**$ 16,568**	**$ 16,968**	**$ 17,368**	**$ 17,768**	**$ 18,168**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**	**$ 18,368**
		Accumulated Deprecation Reserve																														
	9	Beginning Depreciation Reserve	$ -	$ -	$ -	$ 203	$ 664	$ 1,157	$ 1,662	$ 2,179	$ 2,708	$ 3,249	$ 3,795	$ 4,342	$ 4,889	$ 5,436	$ 5,982	$ 6,529	$ 7,076	$ 7,622	$ 8,169	$ 8,716	$ 9,263	$ 9,809	$ 10,356	$ 10,903	$ 11,450	$ 11,996	$ 12,543	$ 13,090	$ 13,637	$ 14,183
	10	Deprecation Expense - Distribution	0	0	203	460	493	505	517	529	541	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
	11	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	17	End Depreciation Reserve	$ -	$ -	$ 203	$ 664	$ 1,157	$ 1,662	$ 2,179	$ 2,708	$ 3,249	$ 3,795	$ 4,342	$ 4,889	$ 5,436	$ 5,982	$ 6,529	$ 7,076	$ 7,622	$ 8,169	$ 8,716	$ 9,263	$ 9,809	$ 10,356	$ 10,903	$ 11,450	$ 11,996	$ 12,543	$ 13,090	$ 13,637	$ 14,183	$ 14,730
	18	**Average Depreciation Reserve**	**$ -**	**$ -**	**$ 102**	**$ 434**	**$ 910**	**$ 1,409**	**$ 1,920**	**$ 2,443**	**$ 2,978**	**$ 3,522**	**$ 4,069**	**$ 4,615**	**$ 5,162**	**$ 5,709**	**$ 6,256**	**$ 6,802**	**$ 7,349**	**$ 7,896**	**$ 8,443**	**$ 8,989**	**$ 9,536**	**$ 10,083**	**$ 10,630**	**$ 11,176**	**$ 11,723**	**$ 12,270**	**$ 12,816**	**$ 13,363**	**$ 13,910**	**$ 14,457**
	19	**Total Average Rate Base**	**$ 1,253**	**$ 7,633**	**$ 13,560**	**$ 15,032**	**$ 15,658**	**$ 15,559**	**$ 15,448**	**$ 15,325**	**$ 15,190**	**$ 14,846**	**$ 14,299**	**$ 13,753**	**$ 13,206**	**$ 12,659**	**$ 12,112**	**$ 11,566**	**$ 11,019**	**$ 10,472**	**$ 9,925**	**$ 9,379**	**$ 8,832**	**$ 8,285**	**$ 7,738**	**$ 7,192**	**$ 6,645**	**$ 6,098**	**$ 5,552**	**$ 5,005**	**$ 4,458**	**$ 3,911**
Benefit		**Plant In Service**																														
	20	Distribution Average Plant In Service	$ -	$ 58	$ 396	$ 1,366	$ 3,387	$ 6,574	$ 10,882	$ 16,280	$ 22,613	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001	$ 26,001
	21	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	22	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	23	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	24	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	26	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	27	**Total Average Plant in Service**	**$ -**	**$ 58**	**$ 396**	**$ 1,366**	**$ 3,387**	**$ 6,574**	**$ 10,882**	**$ 16,280**	**$ 22,613**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**	**$ 26,001**
		Accumulated Deprecation Reserve																														
	28	Beginning Depreciation Reserve	$ -	$ -	$ -	$ -	$ 20	$ 121	$ 317	$ 641	$ 1,125	$ 1,798	$ 2,572	$ 3,346	$ 4,120	$ 4,894	$ 5,668	$ 6,442	$ 7,216	$ 7,990	$ 8,764	$ 9,538	$ 10,312	$ 11,086	$ 11,860	$ 12,634	$ 13,408	$ 14,182	$ 14,955	$ 15,729	$ 16,503	$ 17,277
	29	Deprecation Expense - Distribution	0	0	0	20	101	196	324	485	673	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774
	30	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	31	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	32	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	33	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	34	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	35	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	36	End Depreciation Reserve	$ -	$ -	$ -	$ 20	$ 121	$ 317	$ 641	$ 1,125	$ 1,798	$ 2,572	$ 3,346	$ 4,120	$ 4,894	$ 5,668	$ 6,442	$ 7,216	$ 7,990	$ 8,764	$ 9,538	$ 10,312	$ 11,086	$ 11,860	$ 12,634	$ 13,408	$ 14,182	$ 14,955	$ 15,729	$ 16,503	$ 17,277	$ 18,051
	37	**Average Depreciation Reserve**	**$ -**	**$ -**	**$ -**	**$ 10**	**$ 71**	**$ 219**	**$ 479**	**$ 883**	**$ 1,462**	**$ 2,185**	**$ 2,959**	**$ 3,733**	**$ 4,507**	**$ 5,281**	**$ 6,055**	**$ 6,829**	**$ 7,603**	**$ 8,377**	**$ 9,151**	**$ 9,925**	**$ 10,699**	**$ 11,473**	**$ 12,247**	**$ 13,021**	**$ 13,795**	**$ 14,568**	**$ 15,342**	**$ 16,116**	**$ 16,890**	**$ 17,664**
	38	**Total Average Rate Base**	**$ -**	**$ 58**	**$ 396**	**$ 1,356**	**$ 3,317**	**$ 6,355**	**$ 10,403**	**$ 15,397**	**$ 21,152**	**$ 23,815**	**$ 23,042**	**$ 22,268**	**$ 21,494**	**$ 20,720**	**$ 19,946**	**$ 19,172**	**$ 18,398**	**$ 17,624**	**$ 16,850**	**$ 16,076**	**$ 15,302**	**$ 14,528**	**$ 13,754**	**$ 12,980**	**$ 12,206**	**$ 11,432**	**$ 10,659**	**$ 9,885**	**$ 9,111**	**$ 8,337**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Asset Management BCA Methodology

Case No.: U-22070
Exhibit No.: A-164 (SAM-7)
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Witness: SAMcPhail
Date: June 2026

	Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
Cost	1	Total Average Rate Base	$ 1,253	$ 7,633	$ 13,560	$ 15,032	$ 15,658	$ 15,559	$ 15,448	$ 15,325	$ 15,190	$ 14,846	$ 14,299	$ 13,753	$ 13,206	$ 12,659	$ 12,112	$ 11,566	$ 11,019	$ 10,472	$ 9,925	$ 9,379	$ 8,832	$ 8,285	$ 7,738	$ 7,192	$ 6,645	$ 6,098	$ 5,552	$ 5,005	$ 4,458	$ 3,911	
	2	Total Return on Investment	$ 94	$ 576	$ 1,022	$ 1,133	$ 1,181	$ 1,173	$ 1,165	$ 1,155	$ 1,145	$ 1,119	$ 1,078	$ 1,037	$ 996	$ 954	$ 913	$ 872	$ 831	$ 790	$ 748	$ 707	$ 666	$ 625	$ 583	$ 542	$ 501	$ 460	$ 419	$ 377	$ 336	$ 295	**$ 23,495**
	3	Total Depreciation Expense	-	-	203	460	493	505	517	529	541	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	**14,730**
	4	Total R&PP Tax	17	102	181	201	209	208	206	205	203	198	191	184	176	169	162	154	147	140	132	125	118	111	103	96	89	81	74	67	60	52	**4,160**
	5	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
	6	Total Revenue Requirement	$ 111	$ 677	$ 1,407	$ 1,794	$ 1,883	$ 1,886	$ 1,888	$ 1,889	$ 1,889	$ 1,864	$ 1,816	$ 1,767	$ 1,719	$ 1,670	$ 1,622	$ 1,573	$ 1,525	$ 1,476	$ 1,428	$ 1,379	$ 1,331	$ 1,282	$ 1,234	$ 1,185	$ 1,136	$ 1,088	$ 1,039	$ 991	$ 942	$ 894	**$ 42,385**

	Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
Benefit	1	Total Average Rate Base	$ -	$ 58	$ 396	$ 1,356	$ 3,317	$ 6,355	$ 10,403	$ 15,397	$ 21,152	$ 23,815	$ 23,042	$ 22,268	$ 21,494	$ 20,720	$ 19,946	$ 19,172	$ 18,398	$ 17,624	$ 16,850	$ 16,076	$ 15,302	$ 14,528	$ 13,754	$ 12,980	$ 12,206	$ 11,432	$ 10,659	$ 9,885	$ 9,111	$ 8,337	
	7	Total Return on Investment	$ -	$ 4	$ 30	$ 102	$ 250	$ 479	$ 784	$ 1,161	$ 1,595	$ 1,796	$ 1,737	$ 1,679	$ 1,621	$ 1,562	$ 1,504	$ 1,446	$ 1,387	$ 1,329	$ 1,270	$ 1,212	$ 1,154	$ 1,095	$ 1,037	$ 979	$ 920	$ 862	$ 804	$ 745	$ 687	$ 629	**$ 29,861**
	8	Total Depreciation Expense	-	-	-	20	101	196	324	485	673	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774	**18,051**
	9	Total R&PP Tax	-	1	5	18	44	85	139	206	282	318	308	297	287	277	266	256	246	235	225	215	204	194	184	173	163	153	142	132	122	111	**5,287**
	10	Total O&M Expense	-	14	67	164	315	438	578	693	795	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,063**
	11	Total Revenue Requirement	$ -	$ 19	$ 102	$ 304	$ 710	$ 1,197	$ 1,825	$ 2,544	$ 3,345	$ 2,888	$ 2,819	$ 2,750	$ 2,681	$ 2,613	$ 2,544	$ 2,475	$ 2,407	$ 2,338	$ 2,269	$ 2,201	$ 2,132	$ 2,063	$ 1,995	$ 1,926	$ 1,857	$ 1,789	$ 1,720	$ 1,651	$ 1,583	$ 1,514	**$ 56,261**

	Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
Net Cost (Benefit)	1	Total Average Rate Base	$ 1,253	$ 7,575	$ 13,164	$ 13,677	$ 12,341	$ 9,203	$ 5,045	$ (73)	$ (5,962)	$ (8,969)	$ (8,742)	$ (8,515)	$ (8,288)	$ (8,061)	$ (7,833)	$ (7,606)	$ (7,379)	$ (7,152)	$ (6,925)	$ (6,697)	$ (6,470)	$ (6,243)	$ (6,016)	$ (5,789)	$ (5,561)	$ (5,334)	$ (5,107)	$ (4,880)	$ (4,653)	$ (4,425)	
	12	Total Return on Investment	94	571	993	1,031	931	694	380	(5)	(450)	(676)	(659)	(642)	(625)	(608)	(591)	(574)	(556)	(539)	(522)	(505)	(488)	(471)	(454)	(436)	(419)	(402)	(385)	(368)	(351)	(334)	**$ (6,365)**
	13	Total Depreciation Expense	-	-	203	440	392	309	193	44	(132)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	(227)	**(3,321)**
	14	Total R&PP Tax	17	101	176	183	165	123	67	(1)	(80)	(120)	(117)	(114)	(111)	(108)	(105)	(102)	(99)	(95)	(92)	(89)	(86)	(83)	(80)	(77)	(74)	(71)	(68)	(65)	(62)	(59)	**(1,127)**
	15	Total O&M Expense	-	(14)	(67)	(164)	(315)	(438)	(578)	(693)	(795)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(3,063)**
	16	Total Revenue Requirement	$ 111	$ 659	$ 1,305	$ 1,490	$ 1,172	$ 688	$ 63	$ (655)	$ (1,457)	$ (1,023)	$ (1,003)	$ (983)	$ (963)	$ (943)	$ (922)	$ (902)	$ (882)	$ (862)	$ (842)	$ (822)	$ (801)	$ (781)	$ (761)	$ (741)	$ (721)	$ (701)	$ (680)	$ (660)	$ (640)	$ (620)	**$ (13,876)**

Footnotes:
Pre-tax return 7.54%
R&PP Tax 1.33%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Weather Stations Reliability Benefits

Case No.: U-22070
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Line No.	(a)	(b)
1	**Total Reliability Benefits**	**12,575,250**
2	**Rate Recovery Costs**	**$ 4,498,559**

Avoided CMI

PROJECT ASSUMPTIONS AND DETAILED CALCULATIONS

Assumptions

14 Hrs	**Average restoration time for a typical storm (based on 2024 storms)**
82 Hrs	**Average restoration time for a catastrophic storm (based on 2024 catastrophic storms)**
150	**Average # of crews during "Gray Sky" storm**
10	**Estimate of installation time. (2 hours per weather station, total of 45 weather stations per year)**
15	**Average # of "Gray Sky" or Larger storms per year**
25	**Estimate time (hours) for repairs and maintenance**
1,889,301	**Number of electric customers**
18,900	**Amount of customers needed to be without power in order for a "Gray Sky" storm to be declared**

Benefits Calculations

Reliability SAVINGS CALCULATIONS

18,900	**Amount of customers needed to be without powe**
60	**Number of minutes in the average restoration time saved per storm**
15	**Average # of "Gray Sky" or Larger storms per year**
1,889,301	**Number of electric customers**
1/14	**Fraction of the total restoration time being saved (see A10 for average restoration time for typical storm)**
0.64	**Total SAIDI Savings per year**

	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
SAIDI minutes	0.032	0.193	0.643	0.643	0.643	0.643	0.643	0.643	0.643	0.643	0.643	0.643

	Adding 5	Adding 25	Adding 70									
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Total # of weather stations	5	30	100	100	100	100	100	100	100	100	100	100

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Weather Stations Reliability Benefits

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CAPITAL SPENDING ($000)
Project Name: Weather Stations

Note: Capital Spending entered below should include any AFUDC. If a project was started in 2025 or before the total spend to date related to the project should be entered into the Balance as of 12/31/2025 (including any AFUDC).

Cost

Line Item	Schedule B-5 Category (Drop Down Menu)	Look-Up on B-5 Composite Deprecation Rate	Expected COD	Balance as of (12/31/2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1	Distribution	2.98%	2028	-	1,200	670	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	2.98%	2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Is Project AFUDC Eligible No

O&M Expense ($000)

Line Item	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1																															

Benefits

Line Item	Schedule B-5 Category (Drop Down Menu)	Look-Up on B-5 Composite Deprecation Rate	Expected COD	Balance as of (12/31/2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	2.98%	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Is Project AFUDC Eligible No

O&M Expense ($000)

Line Item	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
1		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TO BE UPATED BY REVENUE REQUIREMENTS:

Per 2025 Historical - See Plant Model Depreciation Rate Table	
Distribution	2.98%
Production (Hydro)	19.76%
Production (Hydro Ludingto	2.77%
Production (Steam)	4.11%
Production (Battery)	6.91%
Production (Other)	2.47%
Intangibles	20.00%
E-GP Structures	2.56%
E-GP Computers	20.00%
E-GP Transportation	1.24%
E-GP Other	5.42%
C-GP Structures	1.56%
C-GP Computers	20.00%
C-GP Transportation	0.53%
C-GP Other	5.17%
Production Acq Adjustment	3.45%
N/A - Line Not Used	

Pre-tax return (approved in U-21870	7.54%
R&PP Tax (U-21870 Exh A-161 (BJV-1	1.33%

Yes
No

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Weather Stations Reliability Benefits

Case No.: U-22070
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	Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Cost		**Plant In Service**																														
	1	Distribution Average Plant In Service	$ 600	$ 1,535	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870	$ 1,870
	2	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	4	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	5	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	6	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	7	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	8	**Total Average Plant in Service**	**$ 600**	**$ 1,535**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**	**$ 1,870**
		Accumulated Deprecation Reserve																														
	9	Beginning Depreciation Reserve	$ -	$ -	$ -	$ 28	$ 83	$ 139	$ 195	$ 250	$ 306	$ 362	$ 417	$ 473	$ 529	$ 584	$ 640	$ 696	$ 751	$ 807	$ 863	$ 918	$ 974	$ 1,030	$ 1,085	$ 1,141	$ 1,197	$ 1,252	$ 1,308	$ 1,364	$ 1,419	$ 1,475
	10	Deprecation Expense - Distribution	0	0	28	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
	11	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	17	End Depreciation Reserve	$ -	$ -	$ 28	$ 83	$ 139	$ 195	$ 250	$ 306	$ 362	$ 417	$ 473	$ 529	$ 584	$ 640	$ 696	$ 751	$ 807	$ 863	$ 918	$ 974	$ 1,030	$ 1,085	$ 1,141	$ 1,197	$ 1,252	$ 1,308	$ 1,364	$ 1,419	$ 1,475	$ 1,531
	18	**Average Depreciation Reserve**	**$ -**	**$ -**	**$ 14**	**$ 56**	**$ 111**	**$ 167**	**$ 223**	**$ 278**	**$ 334**	**$ 390**	**$ 445**	**$ 501**	**$ 557**	**$ 612**	**$ 668**	**$ 724**	**$ 779**	**$ 835**	**$ 891**	**$ 946**	**$ 1,002**	**$ 1,058**	**$ 1,113**	**$ 1,169**	**$ 1,225**	**$ 1,280**	**$ 1,336**	**$ 1,392**	**$ 1,447**	**$ 1,503**
	19	**Total Average Rate Base**	**$ 600**	**$ 1,535**	**$ 1,856**	**$ 1,814**	**$ 1,759**	**$ 1,703**	**$ 1,647**	**$ 1,592**	**$ 1,536**	**$ 1,480**	**$ 1,425**	**$ 1,369**	**$ 1,313**	**$ 1,258**	**$ 1,202**	**$ 1,146**	**$ 1,091**	**$ 1,035**	**$ 979**	**$ 924**	**$ 868**	**$ 812**	**$ 757**	**$ 701**	**$ 645**	**$ 590**	**$ 534**	**$ 478**	**$ 423**	**$ 367**
Benefit		**Plant In Service**																														
	20	Distribution Average Plant In Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	21	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	22	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	23	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	24	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	26	Distribution Average Plant In Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	27	**Total Average Plant in Service**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
		Accumulated Deprecation Reserve																														
	28	Beginning Depreciation Reserve	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	29	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	30	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	31	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	32	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	33	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	34	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	35	Deprecation Expense - Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	36	End Depreciation Reserve	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	37	**Average Depreciation Reserve**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	38	**Total Average Rate Base**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Weather Stations Reliability Benefits

Case No.: U-22070
Exhibit No.: A-165 (SAM-8)
Page: 5 of 5
Witness: SAMcPhail
Date: June 2026

Cost

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ 600	$ 1,535	$ 1,856	$ 1,814	$ 1,759	$ 1,703	$ 1,647	$ 1,592	$ 1,536	$ 1,480	$ 1,425	$ 1,369	$ 1,313	$ 1,258	$ 1,202	$ 1,146	$ 1,091	$ 1,035	$ 979	$ 924	$ 868	$ 812	$ 757	$ 701	$ 645	$ 590	$ 534	$ 478	$ 423	$ 367		
2	Total Return on Investment	$ 45	$ 116	$ 140	$ 137	$ 133	$ 128	$ 124	$ 120	$ 116	$ 112	$ 107	$ 103	$ 99	$ 95	$ 91	$ 86	$ 82	$ 78	$ 74	$ 70	$ 65	$ 61	$ 57	$ 53	$ 49	$ 44	$ 40	$ 36	$ 32	$ 28	**$ 2,521**
3	Total Depreciation Expense	-	-	28	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	**1,531**
4	Total R&PP Tax	8	20	25	24	23	23	22	21	21	20	19	18	18	17	16	15	15	14	13	12	12	11	10	9	9	8	7	6	6	5	**446**
5	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
6	Total Revenue Requirement	$ 53	$ 136	$ 193	$ 217	$ 212	$ 207	$ 202	$ 197	$ 192	$ 187	$ 182	$ 177	$ 172	$ 167	$ 162	$ 157	$ 152	$ 148	$ 143	$ 138	$ 133	$ 128	$ 123	$ 118	$ 113	$ 108	$ 103	$ 98	$ 93	$ 88	**$ 4,499**

Benefit

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
7	Total Return on Investment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
8	Total Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
9	Total R&PP Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
10	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
11	Total Revenue Requirement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**

Net Cost (Benefit)

Line	Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	Total
1	Total Average Rate Base	$ 600	$ 1,535	$ 1,856	$ 1,814	$ 1,759	$ 1,703	$ 1,647	$ 1,592	$ 1,536	$ 1,480	$ 1,425	$ 1,369	$ 1,313	$ 1,258	$ 1,202	$ 1,146	$ 1,091	$ 1,035	$ 979	$ 924	$ 868	$ 812	$ 757	$ 701	$ 645	$ 590	$ 534	$ 478	$ 423	$ 367		
12	Total Return on Investment	45	116	140	137	133	128	124	120	116	112	107	103	99	95	91	86	82	78	74	70	65	61	57	53	49	44	40	36	32	28	**$ 2,521**
13	Total Depreciation Expense	-	-	28	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	**1,531**
14	Total R&PP Tax	8	20	25	24	23	23	22	21	21	20	19	18	18	17	16	15	15	14	13	12	12	11	10	9	9	8	7	6	6	5	**446**
15	Total O&M Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
16	Total Revenue Requirement	$ 53	$ 136	$ 193	$ 217	$ 212	$ 207	$ 202	$ 197	$ 192	$ 187	$ 182	$ 177	$ 172	$ 167	$ 162	$ 157	$ 152	$ 148	$ 143	$ 138	$ 133	$ 128	$ 123	$ 118	$ 113	$ 108	$ 103	$ 98	$ 93	$ 88	**$ 4,499**

Footnotes:
Pre-tax return 7.54%
R&PP Tax 1.33%

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBIT

OF

HEIDI J. MYERS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Investment Recovery Mechanism
Annual Revenue Requirement
($000)

Case No.: U-22070
Exhibit No.: A-166 (HJM-1)
Page: 1 of 3
Witness: HJMyers
Date: June 2026

Line No.	Description	12 Mos. End 4/30/28	12 Mos. End 4/30/29	Source
	(a)	(b)	(c)	(d)
	Capital Investment [1]			
1	Lines Reliability - LVD	208,660	208,660	
2	Lines Reliability - HVD	83,617	83,617	
3	System Protection	4,672	4,672	
4	Resiliency	17,716	17,716	
5	**Total IRM Capital Investment**	**314,665**	**314,665**	Sum Lines 1-4
	Revenue Requirement Summary			
6	Return on Rate Base	12,669	37,671	Page 2, Line 6
7	Depreciation Expense	3,734	11,962	Page 2, Line 9
8	Property Tax	3,832	8,011	Page 2, Line 12
9	**Total Revenue Requirement**	**20,235**	**57,644**	Sum Lines 7-9

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Distribution Investment Recovery Mechanism

Annual Revenue Requirement

($000)

Case No.: U-22070

Exhibit No.: A-166 (HJM-1)

Page: Page 2 of 3

Witness: HJMyers

Date: June 2026

Line No.	Description	12 Mos. End 4/30/28	12 Mos. End 4/30/29	Source
	(a)	(b)	(c)	(e)
1	Average Plant in Service	125,237	401,258	Page 3 Line 4
2	Average CWIP	32,096	70,739	Page 3 Line 9
3	Average Depreciation Reserve	(1,867)	(9,715)	Page 3 Line 13
4	Average Rate Base	155,466	462,283	Sum Lines 1-3
5	Times Pretax Rate of Return	8.15%	8.15%	Line 13
6	Return on Average Rate Base	12,669	37,671	Line 4 X Line 5
7	Depreciable Balance	125,237	401,258	Line 1
8	Depreciation Rate	2.98%	2.98%	Line 14
9	Depreciation Expense	3,734	11,962	Line 7 X Line 8
10	Taxable Balance	282,569	590,687	p3 Line 3 + 50% Line 8
11	Property Tax Rate	0.01356	0.01356	Line 15
12	Property Tax Expense	3,832	8,011	Line 10 X Line 11
13	Pretax Rate of Return	8.15%		Exh. A-14 (MRB-1), Sch. D-1
14	Depreciation Rate	2.98%		WP-HLP-25
15	Property Tax Rate	0.01356		Exh. A-193 (BJV-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Investment Recovery Mechanism
Annual Revenue Requirement
($000)

Case No.: U-22070
Exhibit No.: A-166 (HJM-1)
Page: Page 3 of 3
Witness: HJMyers
Date: June 2026

Line No.	Description	12 Mos. End 4/30/28	12 Mos. End 4/30/29	Source
	(a)	(b)	(c)	(e)
	Plant in Service			
1	Beginning Plant in Service	-	250,473	Line 3
2	Closings	250,473	301,570	(Line 5 + Line 6) * 79.6%
3	Ending Plant in Service	250,473	552,043	Sum Lines 1-3
4	Average Plant in Service	125,237	401,258	Average Line 1 & 3
	Construction Work in Progress			
5	Beginning CWIP	-	64,192	Line 8
6	Capital Spending	314,665	314,665	p1 Line 6
7	Closings	(250,473)	(301,570)	(Line 2)
8	Ending CWIP	64,192	77,287	Sum Lines 4-6
9	Average CWIP	32,096	70,739	Average Line 5 & 8
	Accumulated Depreciation			
10	Beginning Accumulated Depreciation	-	3,734	Line 13
11	Depreciation	3,734	11,962	Page 2 Line 9
12	Ending Accumulated Depreciation	3,734	15,696	Sum Line 10-11
13	Average Accumulated Depreciation	1,867	9,715	Average Line 10 & 12

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

JENNIFER M. PARTLAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
Page: 1 of 35
Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Asset Relocations								
		Associated HVD Lines Project:							
1	LVD Asset Relocations	Greenville (20B STR 606-642)	89	1.8	Miles	LVD Underbuild	Leelanau	Obligation to serve	40,406
2		Bellevue 24A (exit rebuild)	8	0.2	Miles	LVD Underbuild	Calhoun	Obligation to serve	6,095
3		Erie (064O)	350	8.0	Miles	LVD Underbuild	Monroe	Obligation to serve	204,608
4		Nashville (42A Hastings-Nashville)	525	11.2	Miles	LVD Underbuild	Barry	Obligation to serve	138,261
5		LN082F WAYLND 46 KV SPLIT LN BUSKIRK%*13	4	0.1	Miles	LVD Underbuild	Allegan	Obligation to serve	7,778
6		Wirtz Rd 33AE (STR 510 - 800)	350	8.0	Miles	LVD Underbuild	Gladwin	Obligation to serve	435,498
7		Morrice (028I Springbrook - Newburg)	300	6.3	Miles	LVD Underbuild	Shiawassee	Obligation to serve	415,951
8		Niagara (034O)	2	0.0	Miles	LVD Underbuild	Saginaw	Obligation to serve	1,088
9		Hodenpyl (STR 210 - STR104)	175	3.9	Miles	LVD Underbuild	Wexford	Obligation to serve	83,179
10		Golden 49R (STR 376 - 379)	12	0.3	Miles	LVD Underbuild	Midland	Obligation to serve	3,420
11		Golden 49D (STR 377/1 - 5)	4	0.1	Miles	LVD Underbuild	Midland	Obligation to serve	1,140
12		Union St (32F underground replacement)	17	0.4	Miles	LVD Underbuild	Leelanau	Obligation to serve	11,388
13		Golden (049R)	19	0.5	Miles	LVD Underbuild	Midland	Obligation to serve	1,603
14		Stover Line relocates	5	0.0	Miles	LVD Underbuild	Antrim	Obligation to serve	1,212
15		Union City (025A)	42	1.0	Miles	LVD Underbuild	Calhoun	Obligation to serve	-
16		Hughes Rd - 016E	4	0.1	Miles	LVD Underbuild	Calhoun	Obligation to serve	2,652
17		Niagara (034B-Structure #478 to 500)	17	0.4	Miles	LVD Underbuild	Saginaw	Obligation to serve	5,442
18		Walker 115B (STR 4708 - TWR 4731) Grand Valley DBL	87	2.1	Miles	LVD Underbuild	Kent	Obligation to serve	76,935
19		Grand Valley 51F (STR 45- STR 111)	175	3.8	Miles	LVD Underbuild	Kent	Obligation to serve	13,878
20		Merrill 108A (Center)	205	4.6	Miles	LVD Underbuild	Midland	Obligation to serve	43,206
21		Union City (025A)	328	7.9	Miles	LVD Underbuild	Calhoun	Obligation to serve	-
22		Nashville 42A(Hastings-STR 32)	36	0.7	Miles	LVD Underbuild	Barry	Obligation to serve	8,641
23		Mt. Pleasant	167	3.8	Miles	LVD Underbuild	Isabella	Obligation to serve	187,082
24		CEMENT CITY CENTER RBLD 3.38 MI%	175	3.4	Miles	LVD Underbuild	Jackson	Obligation to serve	105,101
25	LVD Asset Relocations	Pole Replacements	4,670	1660	Poles	LVD Underbuild	Various locations statewide	Obligation to serve	1,110,165
26	LVD Asset Relocations	Switch Replacements	1,677	73	Switches	LVD Underbuild	Various locations statewide	Obligation to serve	104,750
27		**LVD Lines Relocations Total - LVD Underbuild**	**9,443**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
Page: 2 of 35
Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/S	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	Right-of-Way Procurement	**13,333**	n/a	n/a	Right of Way			n/a
2	LVD Lines Reliability	LVD Pole Ground Line Inspection Pole Replacements	32,351	3,228	Poles	Pole Replacements	Various locations statewide	Customer-outage-minutes avoided	8302
3	LVD Lines Reliability	POLE LAINGSBURG_ROUND LAKE	1,080	108	Poles	Pole Replacements	SHIAWASSEE	Customer-outage-minutes avoided	278
4		POLE WEST ROAD_WOOD ROAD	40	4	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	10
5		POLE BENNINGTON_GRAND RIVER	1,710	171	Poles	Pole Replacements	SHIAWASSEE	Customer-outage-minutes avoided	440
6		POLE MORRICE_SOUTH MORRICE	2,060	206	Poles	Pole Replacements	SHIAWASSEE	Customer-outage-minutes avoided	530
7		POLE NEWBURG_SHIATOWN	610	61	Poles	Pole Replacements	SHIAWASSEE	Customer-outage-minutes avoided	157
8		POLE DUFFIELD_DUFFIELD	1,280	128	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	329
9		POLE LEHRING_MYERS LAKE	1,820	182	Poles	Pole Replacements	SHIAWASSEE	Customer-outage-minutes avoided	468
10		POLE BISHOP_RAINBOW	550	55	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	141
11		POLE GENESEEVILLE_ROGERS	1,080	108	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	278
12		POLE NEW LOTHROP_REED ROAD	740	74	Poles	Pole Replacements	SHIAWASSEE	Customer-outage-minutes avoided	190
13		POLE OTISVILLE_IRISH ROAD	1,640	164	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	422
14		POLE BELL ROAD_ALBEE	2,270	227	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	584
15		POLE ELSIE_BANNISTER	1,900	190	Poles	Pole Replacements	CLINTON	Customer-outage-minutes avoided	489
16		POLE CHAPIN_CHAPIN	910	91	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	234
17		POLE CHAPIN_MARION	2,100	210	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	540
18		POLE BRECKENRIDGE_VILLAGE	680	68	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	175
19		POLE EDGEWOOD_DISTRIBUTION	1,510	151	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	388
20		POLE MERRILL_MERRILL	960	96	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	247
21		POLE PORTSMOUTH_INDIANTOWN	1,980	198	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	509
22		POLE KNIGHT_FARLEY	1,430	143	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	368
23		POLE OBERLIN_MERIDITH	1,580	158	Poles	Pole Replacements	GLADWIN	Customer-outage-minutes avoided	406
24		POLE COTTAGE GROVE_PREVO	1,900	190	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	489
25		POLE Portage_Mustangs	97	11	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	28
26		POLE LIBERTY_WASHINGTON	261	21	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	54
27		POLE PORTAGE-CARPENTER CORNERS	47	3	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	8
28		POLE DELTON_DELTON	187	39	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	100
29		POLE HAMILTON_HAMILTON	200	20	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	51
30		POLE KINDERHOOK_GILEAD	210	21	Poles	Pole Replacements	BRANCH	Customer-outage-minutes avoided	54
31		POLE PULLMAN_CHICORA	256	54	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	139
32		POLE BELKNAP_TODD FARM	100	10	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	26
33		POLE GUN LAKE ENGLAND	425	33	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	85
34		POLE LETTS RD_MONROE RD	1,170	117	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	301
35		POLE MIDDLETON_NEWARK	1,830	183	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	471
36		POLE EDGEWOOD_DISTRIBUTION	850	85	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	219
37		POLE KAWKAWLIN_RUSSELL	710	71	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	183
38		POLE GLEN LAKE_ARBOR	280	28	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	72
39		POLE BIRCHWOOD_BIRCHWOOD	20	2	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	5
40		POLE BIRCHWOOD_KENMORE	40	4	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	10
41		POLE WEALTHY STREET_INDIANA	60	6	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	15
42		POLE BEALS ROAD_BURTON HEIGHTS	20	2	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	5
43		POLE NEFF ROAD_DODGE ROAD	161	19	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	49
44		POLE BARRYTON_BARRYTON	40	4	Poles	Pole Replacements	MECOSTA	Customer-outage-minutes avoided	10
45		POLE RODNEY_HORSE HEAD LAKE	108	12	Poles	Pole Replacements	MECOSTA	Customer-outage-minutes avoided	31
46		POLE WAYLAND_WAYLAND POLE	18	2	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	5
47		POLE DORR CORNERS_RED RUN	74	10	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	26
48		POLE AUBURN_ELEVATOR	51	8	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	21
49		P0LE HAMMOND ROAD_INDUSTRIAL PARK	120	12	Poles	Pole Replacements	GRAND TRAVERSE	Customer-outage-minutes avoided	31
50		POLE HAMMOND ROAD_AIRPORT RD	30	3	Poles	Pole Replacements	GRAND TRAVERSE	Customer-outage-minutes avoided	8
51		**Pole Replacements Subtotal**	**69,545**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	POLE CASS ROAD_GARFIELD	100	10	Poles	Pole Replacements	GRAND TRAVERSE	Customer-outage-minutes avoided	26
2		POLE TRUFANT_GOWEN	247	29	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	75
3		POLE CASS ROAD_CASS ROAD	20	2	Poles	Pole Replacements	GRAND TRAVERSE	Customer-outage-minutes avoided	5
4		POLE PORTSMOUTH_INDIANTOWN	10	1	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	3
5		POLE ST HELEN_KENO	10	1	Poles	Pole Replacements	ROSCOMMON	Customer-outage-minutes avoided	3
6		POLE Club_Village	190	19	Poles	Pole Replacements	MUSKEGON	Customer-outage-minutes avoided	49
7		POLE MIDLAND_NORTHWOOD	80	8	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	21
8		POLE MONTAGUE_DOWLING POLE	137	12	Poles	Pole Replacements	MUSKEGON	Customer-outage-minutes avoided	31
9		POLE HOSPITAL_KIDS CREEK	6	1	Poles	Pole Replacements	GRAND TRAVERSE	Customer-outage-minutes avoided	3
10		POLE MILLER ROAD_NERREDIA STREET	31	2	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	5
11		POLE FLUSHING_SEYMOUR ROAD	213	19	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	49
12		POLE RAVENNA_MOORLAND	475	41	Poles	Pole Replacements	MUSKEGON	Customer-outage-minutes avoided	105
13		POLE MAYNARD_BESTWALL	50	5	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	13
14		POLE SWARTZ CREEK_MAPLE RD	264	23	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	59
15		POLE BEERS_BALDWIN RD	282	23	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	59
16		POLE REED CITY_HOLDENVILLE	189	19	Poles	Pole Replacements	OSCEOLA	Customer-outage-minutes avoided	49
17		POLE PEARLINE_COPPER BEACH	9	2	Poles	Pole Replacements	OTTAWA	Customer-outage-minutes avoided	5
18		POLE HARVARD LAKE_HARVARD LAKE	290	29	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	75
19		POLE Greenwood_M-33	250	25	Poles	Pole Replacements	OGEMAW	Customer-outage-minutes avoided	64
20		POLE PEARLINE_WINDFIELD	9	2	Poles	Pole Replacements	OTTAWA	Customer-outage-minutes avoided	5
21		POLE25 Backus_Springbrook	177	19	Poles	Pole Replacements	ROSCOMMON	Customer-outage-minutes avoided	49
22		POLE HARVARD LAKE_COURTLAND	120	12	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	31
23		POLE HARRIET_HARRIET	257	22	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	57
24		POLE NUNICA_LEONARD	259	34	Poles	Pole Replacements	OTTAWA	Customer-outage-minutes avoided	87
25		POLE FROST_LEOTA	180	18	Poles	Pole Replacements	CLARE	Customer-outage-minutes avoided	46
26		POLE MILE RD_INDUSTRIAL PARK	162	14	Poles	Pole Replacements	MECOSTA	Customer-outage-minutes avoided	36
27		POLE STANTON_DICKERSON LAKE	160	16	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	41
28		RLBY POLE LEVELY_ALLBRIGHT	150	15	Poles	Pole Replacements	GLADWIN	Customer-outage-minutes avoided	39
29		POLE O-AT-KA_PINE GROVE	60	6	Poles	Pole Replacements	GRAND TRAVERSE	Customer-outage-minutes avoided	15
30		POLE SHATTUCK_CENTER ROAD	120	12	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	31
31		POLE TRUFANT_HUNTER LAKE	540	54	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	139
32		POLE KNIGHT_FARLEY	180	18	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	46
33		POLE LYONS_COLLINS-RURAL	152	20	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	51
34		POLE COTTAGE GROVE_PREVO	86	8	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	21
35		POLE NORTHPORT_LIGHTHOUSE	160	16	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	41
36		POLE NORTHPORT_MANITOU	120	12	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	31
37		POLE GLEN LAKE_BURDICKVILLE	180	18	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	46
38		POLE SMITH CREEK_SKIPARK	15	1	Poles	Pole Replacements	OGEMAW	Customer-outage-minutes avoided	3
39		POLE ALABAMA_KING ROAD	4	1	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	3
40		POLE ALABAMA_YANKEE	23	3	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	8
41		POLE BRIDGEPORT_DIXIE	310	31	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	80
42		POLE BRIDGEPORT_BRIDGEPORT	92	12	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	31
43		POLE Whittemore Reno	100	10	Poles	Pole Replacements	IOSCO	Customer-outage-minutes avoided	26
44		POLE DALE ROAD_M-18	39	5	Poles	Pole Replacements	GLADWIN	Customer-outage-minutes avoided	13
45		POLE CLIMAX_CLIMAX	400	40	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	103
46		POLE GLENDALE_KEYES	250	25	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	64
47		POLE MARTIN_SHELBYVILLE	260	26	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	67
48		POLE MENDON_M-60	420	42	Poles	Pole Replacements	ST JOSEPH	Customer-outage-minutes avoided	108
49		POLE AUGUSTA_AUGUSTA	1,480	148	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	381
50		POLE KILGORE_TIMBERLANE	90	9	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	23
51		POLE KENDALL_SAGE	550	35	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	90
52		POLE KILGORE_WISTERIA	60	6	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	15
53		POLE NEFF ROAD_LEWIS ROAD	430	43	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	111
54		POLE OSHTEMO_ALMENA	30	3	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	8
55		POLE DUQUITE_SAGANING	687	64	Poles	Pole Replacements	ARENAC	Customer-outage-minutes avoided	165
56		POLE DELTON_DELTON	30	3	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	8
57		POLE TAMARACK_LAKEVIEW	550	55	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	141
58		POLE BYRON CENTER_CARLISLE	150	15	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	39
59		POLE CLIMAX_AGGREGATES	50	5	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	13
60		POLE GULL LAKE_WILLOW BEACH	40	4	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	10
61		**Pole Replacements Subtotal**	**11,986**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
Page: 4 of 35
Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected riod Spend	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	POLE WHITTUM_KINNEVILLE	30	3	Poles	Pole Replacements	EATON	Customer-outage-minutes avoided	8
2		POLE HARPER ROAD_AURELIUS	40	4	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	10
3		POLE UPTON_MT HOPE	90	9	Poles	Pole Replacements	EATON	Customer-outage-minutes avoided	23
4		POLE NORTH LANSING_VALLEY FARMS	230	23	Poles	Pole Replacements	CLINTON	Customer-outage-minutes avoided	59
5		POLE DIMONDALE_ROSSMAN	390	39	Poles	Pole Replacements	EATON	Customer-outage-minutes avoided	100
6		POLE WHITTUM_M-50	60	6	Poles	Pole Replacements	EATON	Customer-outage-minutes avoided	15
7		POLE POTTERVILLE_POTTERVILLE	60	6	Poles	Pole Replacements	EATON	Customer-outage-minutes avoided	15
8		POLE WHITTUM_ROYSTON	160	16	Poles	Pole Replacements	EATON	Customer-outage-minutes avoided	41
9		POLE BEHNKE_RIVER RD	300	30	Poles	Pole Replacements	BRANCH	Customer-outage-minutes avoided	77
10		POLE BELL ROAD_ALBEE	430	43	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	111
11		POLE BLUE WATER_TOWNSEND RD	60	6	Poles	Pole Replacements	CLINTON	Customer-outage-minutes avoided	15
12		POLE BURR OAK_INDUSTRIAL	460	46	Poles	Pole Replacements	ST JOSEPH	Customer-outage-minutes avoided	118
13		POLE CHESANING_PEET	420	42	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	108
14		POLE CLOVERLEAF_ELY HWY	290	29	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	75
15		POLE COLEMAN_COLEMAN	120	12	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	31
16		POLE COLON_COLON	350	35	Poles	Pole Replacements	ST JOSEPH	Customer-outage-minutes avoided	90
17		POLE COLON_PALMER	310	31	Poles	Pole Replacements	ST JOSEPH	Customer-outage-minutes avoided	80
18		POLE DUTTON_GLENWOOD	210	21	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	54
19		POLE Elm St_Main	330	33	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	85
20		POLE ELM STREET_PORTER	330	33	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	85
21		POLE ELM STREET_CHAMPION	370	37	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	95
22		POLE FINE LAKE_BRISTOL	330	33	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	85
23		POLE FRONTIER_RANSOM	400	40	Poles	Pole Replacements	HILLSDALE	Customer-outage-minutes avoided	103
24		POLE GILSON_WYMAN	330	33	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	85
25		POLE HOMESTEAD_JOYFIELD	370	37	Poles	Pole Replacements	BENZIE	Customer-outage-minutes avoided	95
26		POLE HOMESTEAD_BEULAH	300	30	Poles	Pole Replacements	BENZIE	Customer-outage-minutes avoided	77
27		POLE HUBBARDSTON ROAD_HUBBARDSTON	340	34	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	87
28		POLE HUNT ROAD_MOORE ROAD	460	46	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	118
29		POLE KNIGHT_ROSEMARY	350	35	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	90
30		POLE KOLASSA_KOSMERICK	380	38	Poles	Pole Replacements	BRANCH	Customer-outage-minutes avoided	98
31		POLE LEITH STREET_FRANKLIN	270	27	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	69
32		POLE WATKINS_HAMILTON	110	11	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	28
33		POLE CARLETON ROAD_GAIGE ROAD	20	2	Poles	Pole Replacements	HILLSDALE	Customer-outage-minutes avoided	5
34		POLE CARLETON ROAD_BECK ROAD	40	4	Poles	Pole Replacements	HILLSDALE	Customer-outage-minutes avoided	10
35		POLE WATKINS_KNAPP	20	2	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	5
36		POLE HALLS LAKE_HALLS LAKE	30	3	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	8
37		POLE MESICK_SHERMAN	440	44	Poles	Pole Replacements	WEXFORD	Customer-outage-minutes avoided	113
38		POLE JONESVILLE_JONESVILLE	50	5	Poles	Pole Replacements	HILLSDALE	Customer-outage-minutes avoided	13
39		POLE READING_CITY	20	2	Poles	Pole Replacements	HILLSDALE	Customer-outage-minutes avoided	5
40		POLE Morgan_Orchard	360	36	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	93
41		POLE JONESVILLE_MILNES	20	2	Poles	Pole Replacements	HILLSDALE	Customer-outage-minutes avoided	5
42		POLE OLIVET_COLLEGE	430	43	Poles	Pole Replacements	EATON	Customer-outage-minutes avoided	111
43		POLE ONSTED_ROME CENTER	380	38	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	98
44		POLE ORLEANS_LONG LAKE	280	28	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	72
45		POLE Columbia_Airport	20	2	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	5
46		POLE Columbia_Columbia	50	5	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	13
47		POLE Renton_Watkins	220	22	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	57
48		POLE Morgan_St Mary's	430	43	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	111
49		POLE Elm St_Verona	640	64	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	165
50		POLE Alder Creek_Lee Lake	1,350	135	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	347
51		POLE Ft Custer_Guard	40	4	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	10
52		POLE Bedford_Halbert	80	8	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	21
53		POLE Springfield_Biscuit	60	6	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	15
54		POLE Ft Custer_Harmonia	150	15	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	39
55		POLE Springfield_Upton	360	36	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	93
56		POLE Bedford_Meachem	110	11	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	28
57		POLE PARNALL_PARNALL RD	220	22	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	57
58		POLE GERRISH_MERRIO	60	6	Poles	Pole Replacements	ROSCOMMON	Customer-outage-minutes avoided	15
59		POLE CHESANING_CHESANING	240	24	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	62
60		POLE CHESANING_OAKLEY	230	23	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	59
61		**Pole Replacements Subtotal**	**15,030**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
Page: 5 of 35
Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected riod Spend	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	POLE PINCONNING_PINCONNING	410	41	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	105
2		POLE MILLER ROAD_YALE STREET	70	7	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	18
3		POLE BOMAN_RIVERVIEW	110	11	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	28
4		POLE CALKINS_FLUSHING ROAD	160	16	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	41
5		POLE WAGER_FLINT PARK	290	29	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	75
6		POLE SQUIRE HILL_HILLSIDE	50	5	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	13
7		POLE SLOAN_LAVELLE ROAD	70	7	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	18
8		POLE RIVERDALE_SUMNER	380	38	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	98
9		POLE FOREMAN_VERGENNES	110	11	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	28
10		POLE AUGUSTA_HOSPITAL	20	2	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	5
11		POLE CALVIN_ROSEMONT	30	3	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	8
12		POLE DUTTON_DUTTON	30	3	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	8
13		POLE DUTTON_CRYSTAL SPRINGS	50	5	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	13
14		POLE CALEDONIA_92ND STREET	140	14	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	36
15		POLE COOPER_NAGEL	110	11	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	28
16		POLE SANDERSON_COUNTY FARM	260	26	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	67
17		POLE KALARAMA_ROMENCE	80	8	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	21
18		POLE MIDWAY_NAOMI	40	4	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	10
19		POLE DRAKE ROAD_COUNTRY CLUB	20	2	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	5
20		POLE KALARAMA_ANGLING	100	10	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	26
21		POLE EASTWOOD_EAST	40	4	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	10
22		POLE HASKELITE_RICHMOND	10	1	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	3
23		POLE STANDALE_PARKSIDE	20	2	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	5
24		POLE ZYLMAN_ZYLMAN	90	9	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	23
25		POLE FOUR MILE_GREENRIDGE	40	4	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	10
26		POLE HARVEY STREET_SUNSHINE	10	1	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	3
27		POLE TWELFTH STREET_WESTFIELD	40	4	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	10
28		POLE PALMER_REED	70	7	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	18
29		POLE RIVERTOWN_SATTLER	20	2	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	5
30		POLE KILGORE_MOUNT EVEREST	110	11	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	28
31		POLE PAVILION_MERIDETH	20	2	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	5
32		POLE PICKEREL_INDIAN LAKE	50	5	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	13
33		POLE PICKEREL_EAST LAKE	60	6	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	15
34		POLE WEALTHY STREET_NORTHWEST	40	4	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	10
35		POLE LINDEN_NORTH LINDEN	40	4	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	10
36		POLE KILGORE_MILHAM	20	2	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	5
37		POLE PALMER_HEALY	10	1	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	3
38		POLE OAKWOOD_BROADWAY	190	19	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	49
39		POLE KROMDYKE_RAMONA	10	1	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	3
40		POLE SCOTTS_WHITE	90	9	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	23
41		POLE PALMER_WATER LIFT	60	6	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	15
42		POLE TWILIGHT_GULL ROAD	30	3	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	8
43		POLE TEXAS_BASS LAKE	40	4	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	10
44		POLE MOSEL_ALLEN	40	4	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	10
45		POLE PALMER_LAKESIDE	10	1	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	3
46		POLE PAVILION_DAVIS CREEK	10	1	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	3
47		POLE SCOTTS_SCOTTS	180	18	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	46
48		POLE RIVERTOWN_POTOMAC	30	3	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	8
49		POLE BOSTON SQUARE_MULICK PARK	50	5	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	13
50		POLE OAKWOOD_PARKVIEW	40	4	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	10
51		POLE WEALTHY STREET_GODFREY	30	3	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	8
52		POLE MOSEL_PITCHER	60	6	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	15
53		POLE BEALS ROAD_DIVISION ROAD	30	3	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	8
54		POLE BOSTON SQUARE_KALAMAZOO	80	8	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	21
55		POLE ABERDEEN_HOLLYWOOD	40	4	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	10
56		POLE TEXAS_EAGLE LAKE	100	10	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	26
57		POLE KELLOGGSVILLE_MAJESTIC	50	5	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	13
58		POLE HASKELITE_BISSELL	40	4	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	10
59		POLE STADIUM_COLLEGE	110	11	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	28
60		POLE SINCLAIR_HERITAGE HILL	20	2	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	5
61		**Pole Replacements Subtotal**	**4,560**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	POLE HASKELITE_3 MILE	40	4	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	10
2		POLE LEFFINGWELL_NOTTINGHAM	30	3	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	8
3		POLE BOSTON SQUARE_HALL	60	6	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	15
4		POLE LINDEN_LOBDELL	80	8	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	21
5		POLE BOSTON SQUARE_NELAND	80	8	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	21
6		POLE SWARTZ CREEK_MORRISH ROAD	80	8	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	21
7		POLE COOPER_COOPER CENTER	20	2	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	5
8		POLE READING_CAMBRIA	240	24	Poles	Pole Replacements	HILLSDALE	Customer-outage-minutes avoided	62
9		POLE ABERDEEN_RICKMAN	290	29	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	75
10		POLE OAKWOOD_HILLCREST	60	6	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	15
11		POLE ATWATER_CRONK	20	2	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	5
12		POLE MT MORRIS_WOOLFIT	150	15	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	39
13		POLE JUDD ROAD_OTTAWA	40	4	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	10
14		POLE JUDD ROAD_HOLIDAY	40	4	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	10
15		POLE LENNON ROAD_SHOPPERS	20	2	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	5
16		POLE JUDD ROAD_MANDEVILLE	180	18	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	46
17		POLE OSHTEMO_HURD	30	3	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	8
18		POLE MANITOU BEACH_DEVILS LAKE	150	15	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	39
19		POLE JUDD ROAD_CARMANWOOD	10	1	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	3
20		POLE LENNON ROAD_OTTERBURN	20	2	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	5
21		POLE MICHIGAN_LOOKOUT	90	9	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	23
22		POLE KELLOGGSVILLE_LEISURE	70	7	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	18
23		POLE PECK ROAD_WISE ROAD	30	3	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	8
24		POLE BELDING_COOKS CORNERS	90	9	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	23
25		POLE BIG PRAIRIE_BIG BEND	80	8	Poles	Pole Replacements	NEWAYGO	Customer-outage-minutes avoided	21
26		POLE LYONS_LYONS-MUIR	150	15	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	39
27		POLE BURLINGAME_MICHAEL	160	16	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	41
28		POLE BURLINGAME_NEWHALL	100	10	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	26
29		POLE FOUR MILE_CORDES	50	5	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	13
30		POLE CENTREVILLE_LAKE TEMPLENE	340	34	Poles	Pole Replacements	ST JOSEPH	Customer-outage-minutes avoided	87
31		POLE BECK ROAD_CONSEAR	110	11	Poles	Pole Replacements	MONROE	Customer-outage-minutes avoided	28
32		POLE WILDWOOD_YARDMAN	30	3	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	8
33		POLE Prescott_Maple Ridge	160	16	Poles	Pole Replacements	OGEMAW	Customer-outage-minutes avoided	41
34		POLE LEE STREET_KIRTLAND	50	5	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	13
35		POLE PLAINFIELD_BELMONT	40	4	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	10
36		POLE PEACH RIDGE_BALLARD	150	15	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	39
37		POLE GREENVILLE_WILLIAMS ST	210	21	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	54
38		POLE GREENVILLE_WASHINGTON ST	260	26	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	67
39		POLE WALKER_REMEMBRANCE	50	5	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	13
40		POLE MANITOU BEACH_ADDISON	200	20	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	51
41		POLE NORTON_HILE ROAD	160	16	Poles	Pole Replacements	MUSKEGON	Customer-outage-minutes avoided	41
42		POLE BURLINGAME_BURLINGAME	160	16	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	41
43		POLE COLLEGE PARK_RIVERSIDE	110	11	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	28
44		POLE BEADLE_SPAULDING	240	24	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	62
45		POLE MAUMEE_LENAWEE ST	190	19	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	49
46		POLE TEMPERANCE_WOOD ROAD	130	13	Poles	Pole Replacements	MONROE	Customer-outage-minutes avoided	33
47		POLE Noble_Whitney	110	11	Poles	Pole Replacements	ARENAC	Customer-outage-minutes avoided	28
48		POLE DEERFIELD_RODESILER	170	17	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	44
49		POLE BLISSFIELD_CITY	150	15	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	39
50		POLE HALEY ROAD_MEDINA	100	10	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	26
51		POLE BEECHER_DISPOSAL	30	3	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	8
52		POLE BEECHER_ANDERSON	50	5	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	13
53		POLE MARKER LAKE_KYSER ROAD	40	4	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	10
54		POLE FAIRFIELD_WESTON	170	17	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	44
55		POLE REED CITY_MEDICAL - ESIC OHL	70	7	Poles	Pole Replacements	OSCEOLA	Customer-outage-minutes avoided	18
56		POLE BLISSFIELD_SUGAR MILL	130	13	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	33
57		POLE QUINCY_CHICAGO ROAD	260	26	Poles	Pole Replacements	BRANCH	Customer-outage-minutes avoided	67
58		POLE WALDRON_BETZER	60	6	Poles	Pole Replacements	HILLSDALE	Customer-outage-minutes avoided	15
59		POLE TRIPP ROAD_TRIPP ROAD	250	25	Poles	Pole Replacements	HILLSDALE	Customer-outage-minutes avoided	64
60		POLE LAMBERTVILLE_SUMMERFIELD	110	11	Poles	Pole Replacements	MONROE	Customer-outage-minutes avoided	28
61		**Pole Replacements Subtotal**	**6,750**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	POLE LASALLE_TELEGRAPH	20	2	Poles	Pole Replacements	MONROE	Customer-outage-minutes avoided	5
2		POLE TEMPERANCE_CRABB ROAD	150	15	Poles	Pole Replacements	MONROE	Customer-outage-minutes avoided	39
3		POLE FAIRFIELD_JASPER	240	24	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	62
4		POLE QUINCY_QUINCY	270	27	Poles	Pole Replacements	BRANCH	Customer-outage-minutes avoided	69
5		POLE NORTH ADAMS_BUCK LAKE	560	56	Poles	Pole Replacements	HILLSDALE	Customer-outage-minutes avoided	144
6		POLE BEHNKE_ANGOLA ROAD	90	9	Poles	Pole Replacements	BRANCH	Customer-outage-minutes avoided	23
7		POLE SPRINGFIELD_HELMER	280	28	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	72
8		POLE CONVIS_CONVIS	20	2	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	5
9		POLE TEKONSHA_TEKONSHA	510	51	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	131
10		POLE Whittemore M-65	120	12	Poles	Pole Replacements	IOSCO	Customer-outage-minutes avoided	31
11		POLE LOMBARD_SHERIDAN	260	26	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	67
12		POLE LAMBERTVILLE_WHITEFORD	40	4	Poles	Pole Replacements	MONROE	Customer-outage-minutes avoided	10
13		POLE LASALLE_DIXIE	160	16	Poles	Pole Replacements	MONROE	Customer-outage-minutes avoided	41
14		POLE AUSTIN_LONG LAKE	20	2	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	5
15		POLE PALMYRA_DRIGGS	540	54	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	139
16		POLE TEKONSHA_WAGNER	510	51	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	131
17		POLE ELM STREET_VAN BUREN	10	1	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	3
18		POLE ERIE_PERE MARQUETTE	100	10	Poles	Pole Replacements	MONROE	Customer-outage-minutes avoided	26
19		POLE AUBURN_AUBURN	230	23	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	59
20		POLE Bessinger_Quarry	200	20	Poles	Pole Replacements	ARENAC	Customer-outage-minutes avoided	51
21		POLE ERIE_COUSINO ROAD	90	9	Poles	Pole Replacements	MONROE	Customer-outage-minutes avoided	23
22		POLE LASALLE_OTTER CREEK	250	25	Poles	Pole Replacements	MONROE	Customer-outage-minutes avoided	64
23		POLE MICHIGAN CENTER_BALLARD	80	8	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	21
24		POLE Prescott_Logan	150	15	Poles	Pole Replacements	OGEMAW	Customer-outage-minutes avoided	39
25		POLE LOMBARD_LOMBARD	240	24	Poles	Pole Replacements	CALHOUN	Customer-outage-minutes avoided	62
26		POLE MICHIGAN CENTER_PAGE	260	26	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	67
27		POLE Alger_Forest Lake	480	48	Poles	Pole Replacements	ARENAC	Customer-outage-minutes avoided	123
28		POLE CARY ROAD_JEFFERSON ROAD	70	7	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	18
29		POLE Turner_Gates	150	15	Poles	Pole Replacements	ARENAC	Customer-outage-minutes avoided	39
30		POLE MANCHESTER_AUSTIN ROAD	80	8	Poles	Pole Replacements	WASHTENAW	Customer-outage-minutes avoided	21
31		POLE ESSEXVILLE_CENTER ROAD	10	1	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	3
32		POLE BRIDGE STREET_WATER STREET	160	16	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	41
33		POLE INGHAM_GREENWOOD PARK	50	5	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	13
34		POLE MANCHESTER_LOGAN ROAD	160	16	Poles	Pole Replacements	WASHTENAW	Customer-outage-minutes avoided	41
35		POLE OHMAN ROAD_HERSEY	100	10	Poles	Pole Replacements	OSCEOLA	Customer-outage-minutes avoided	26
36		POLE LESLIE_BUSINESS	60	6	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	15
37		POLE FOREST GROVE_ROYAL	10	1	Poles	Pole Replacements	OTTAWA	Customer-outage-minutes avoided	3
38		POLE PECK ROAD_M-91	20	2	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	5
39		POLE FOREST GROVE_GREENLY	20	2	Poles	Pole Replacements	OTTAWA	Customer-outage-minutes avoided	5
40		POLE Withey Lake_Petit	250	25	Poles	Pole Replacements	OGEMAW	Customer-outage-minutes avoided	64
41		POLE MANCHESTER_DUNCAN	240	24	Poles	Pole Replacements	WASHTENAW	Customer-outage-minutes avoided	62
42		POLE CADILLAC_CENTRAL	340	34	Poles	Pole Replacements	WEXFORD	Customer-outage-minutes avoided	87
43		POLE BATTEESE_MUNITH	320	32	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	82
44		POLE PARNALL_DISPOSAL	140	14	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	36
45		POLE MAINES ROAD_WELLMAN ROAD	20	2	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	5
46		POLE BATTEESE_COON HILL	230	23	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	59
47		POLE CARY ROAD_MOSCOW	240	24	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	62
48		POLE FREELAND_RURAL	50	5	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	13
49		POLE BROOKLYN_FORD	50	5	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	13
50		POLE REYNOLDS_SEARS	10	1	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	3
51		POLE OAK STREET_COOPER STREET	10	1	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	3
52		POLE OAK STREET_WEST GANSON	20	2	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	5
53		POLE BALZER_COMSTOCK	80	8	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	21
54		POLE CARY ROAD_WOODSTOCK	130	13	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	33
55		POLE OAK STREET_PLYMOUTH	50	5	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	13
56		POLE INGHAM_THIRD STREET	10	1	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	3
57		POLE CARY ROAD_LAKE COLUMBIA	220	22	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	57
58		POLE CLEAR LAKE_WATERLOO	70	7	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	18
59		POLE BRIDGE STREET_HUPP AVENUE	40	4	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	10
60		POLE BATTEESE_PLEASANT LAKE	250	25	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	64
61		**Pole Replacements Subtotal**	**9,540**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
Page: 8 of 35
Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	POLE HOPKINS_MONTEREY	570	57	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	147
2		POLE VANDERCOOK LAKE_HAGUE ROAD	220	22	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	57
3		POLE VANDERCOOK LAKE_VANDERCOOK LAKE POL	150	15	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	39
4		POLE OAK STREET_STATE STREET	30	3	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	8
5		POLE ONSTED_ONSTED	200	20	Poles	Pole Replacements	LENAWEE	Customer-outage-minutes avoided	51
6		POLE ESSEXVILLE_ESSEXVILLE	60	6	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	15
7		POLE WISNER_MONROE	20	2	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	5
8		POLE BROUGHWELL_SURBROOK	370	37	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	95
9		POLE BLACKMAN_HURST	20	2	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	5
10		POLE Backus_Maple Valley	110	11	Poles	Pole Replacements	ROSCOMMON	Customer-outage-minutes avoided	28
11		POLE FREELAND_FREELAND	140	14	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	36
12		POLE BROUGHWELL_MINARD	50	5	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	13
13		POLE CADILLAC_BERRY LAKE	20	2	Poles	Pole Replacements	WEXFORD	Customer-outage-minutes avoided	5
14		POLE WEST CLARK LAKE_EAGLE POINT	50	5	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	13
15		POLE WEST CLARK LAKE_GRAND	40	4	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	10
16		POLE BLACKMAN_SANDSTONE	30	3	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	8
17		POLE EAST JACKSON_TROJAN	70	7	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	18
18		POLE ASHLEY_GARFIELD	30	3	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	8
19		POLE EIGHT POINT_WHITE BIRCH	70	7	Poles	Pole Replacements	CLARE	Customer-outage-minutes avoided	18
20		POLE PECK ROAD_ORE-IDA	50	5	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	13
21		POLE CUTLERVILLE_GAINES	70	7	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	18
22		POLE REED CITY_HIGH SCHOOL	80	8	Poles	Pole Replacements	MECOSTA	Customer-outage-minutes avoided	21
23		POLE HARRISON_STOCKWELL	230	23	Poles	Pole Replacements	CLARE	Customer-outage-minutes avoided	59
24		POLE EIGHT POINT_LAKE GEORGE	80	8	Poles	Pole Replacements	CLARE	Customer-outage-minutes avoided	21
25		POLE CARROLLTON_CARROLLTON	260	26	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	67
26		POLE BULLOCK_PRAIRIE	10	1	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	3
27		POLE NORTH ALLEGAN_HUBBARD	140	14	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	36
28		POLE SALEM_BURNIPS	180	18	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	46
29		POLE SALEM_NORTH DORR	590	59	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	152
30		POLE MARTIN_HYBELS	120	12	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	31
31		POLE FROST_LONG LAKE	40	4	Poles	Pole Replacements	CLARE	Customer-outage-minutes avoided	10
32		POLE NORTH ALLEGAN_ROCKWELL	130	13	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	33
33		POLE MIDDLETON_MIDDLETON	110	11	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	28
34		POLE SHIELDS_SHIELDS	160	16	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	41
35		POLE ROSCOMMON_SOUTH BRANCH	60	6	Poles	Pole Replacements	ROSCOMMON	Customer-outage-minutes avoided	15
36		POLE ALDRICH_COUNTY	50	5	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	13
37		POLE POTTER_KIRK	90	9	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	23
38		POLE RUSSELLVILLE_RICHFIELD	130	13	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	33
39		POLE TEFT ROAD_GRAHAM	60	6	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	15
40		POLE DORR CORNERS_100TH STREET	150	15	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	39
41		POLE IRON STREET_TERM	40	4	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	10
42		POLE STANWOOD_TYLER ROAD	220	22	Poles	Pole Replacements	MECOSTA	Customer-outage-minutes avoided	57
43		POLE GILKEY CREEK_WOLCOTT	100	10	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	26
44		POLE HOPKINS_HOPKINS	50	5	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	13
45		POLE ALAMO_OWEN	140	14	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	36
46		POLE ROSCOMMON_PIONEER	90	9	Poles	Pole Replacements	ROSCOMMON	Customer-outage-minutes avoided	23
47		POLE FOURTEENTH STREET_TOBIAS ST	100	10	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	26
48		POLE STATE STREET_MACKINAW	100	10	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	26
49		POLE ALAMO_PINE GROVE	390	39	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	100
50		POLE FOURTEENTH STREET_LIPPINCOTT STREET	140	14	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	36
51		POLE IRISH ROAD_CRYSTALWOOD	100	10	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	26
52		POLE BULLOCK_STEWART	330	33	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	85
53		POLE THOMAS_THOMAS	50	5	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	13
54		POLE FOURTEENTH STREET_LIBERTY STREET	90	9	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	23
55		POLE TEFT ROAD_LAKEFIELD	90	9	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	23
56		POLE INGERSOLL_SASSE	220	22	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	57
57		POLE FOURTEENTH STREET_SOUTH WESTERN	120	12	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	31
58		POLE SURREY_SURREY	130	13	Poles	Pole Replacements	CLARE	Customer-outage-minutes avoided	33
59		POLE MANNSIDING_CEDAR	120	12	Poles	Pole Replacements	CLARE	Customer-outage-minutes avoided	31
60		POLE IRISH ROAD_BELLE MEADE	10	1	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	3
61		**Pole Replacements Subtotal**	**7,670**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	POLE ST CHARLES_SAGINAW	460	46	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	118
2		POLE MAGNUS_MCKAY FARM	10	1	Poles	Pole Replacements	CLARE	Customer-outage-minutes avoided	3
3		POLE MILL GROVE_ALLEGAN HYDRO	150	15	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	39
4		POLE OBERLIN_PRATT LAKE	70	7	Poles	Pole Replacements	GLADWIN	Customer-outage-minutes avoided	18
5		POLE SURREY_MAIN STREET	110	11	Poles	Pole Replacements	ISABELLA	Customer-outage-minutes avoided	28
6		POLE OBERLIN_BENMARK	150	15	Poles	Pole Replacements	GLADWIN	Customer-outage-minutes avoided	39
7		POLE LEELANAU_OMENA BAY	110	11	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	28
8		POLE NORTHPORT_OMENA	70	7	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	18
9		POLE BRECKENRIDGE_WHEELER	150	15	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	39
10		POLE PINCONNING_WHITE FEATHER	170	17	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	44
11		POLE CARROLLTON_MAPLE RIDGE	50	5	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	13
12		POLE CARROLLTON_ZILWAUKEE	40	4	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	10
13		POLE DUQUITE_JOHNSFIELD	210	21	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	54
14		POLE MARION_GASCOM	100	10	Poles	Pole Replacements	OSCEOLA	Customer-outage-minutes avoided	26
15		POLE MCBAIN_VOGEL CENTER	80	8	Poles	Pole Replacements	MISSAUKEE	Customer-outage-minutes avoided	21
16		POLE LAKE ODESSA_LAKE	60	6	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	15
17		POLE HUBBARDSTON ROAD_STONEY CREEK	130	13	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	33
18		POLE HOUGHTON HEIGHTS_MERRITT	130	13	Poles	Pole Replacements	MISSAUKEE	Customer-outage-minutes avoided	33
19		POLE CEDAR LAKE_VAN ETTEN RUSH	100	10	Poles	Pole Replacements	IOSCO	Customer-outage-minutes avoided	26
20		POLE GRAYLING_RIVER RUSH	100	10	Poles	Pole Replacements	CRAWFORD	Customer-outage-minutes avoided	26
21		POLE ROSE CITY_COYOTES	100	10	Poles	Pole Replacements	OGEMAW	Customer-outage-minutes avoided	26
22		POLE BARNARD_WEISS	90	9	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	23
23		POLE SMALLWOOD DAM_DISTRIBUTION	50	5	Poles	Pole Replacements	GLADWIN	Customer-outage-minutes avoided	13
24		POLE MCBAIN_LAKE CITY	90	9	Poles	Pole Replacements	MISSAUKEE	Customer-outage-minutes avoided	23
25		POLE FREEPORT_CARLTON CENTER	510	51	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	131
26		POLE LAKE ODESSA_INDUSTRIAL	50	5	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	13
27		POLE LAKE ODESSA_BONANZA	10	1	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	3
28		POLE MIDDLEVILLE_BUSINESS	30	3	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	8
29		POLE CRYSTAL_CRYSTAL ROAD	410	41	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	105
30		POLE BARRYTON_CHIPPEWA LAKE	110	11	Poles	Pole Replacements	MECOSTA	Customer-outage-minutes avoided	28
31		POLE NINETEEN MILE RD_CEMENT	160	16	Poles	Pole Replacements	MECOSTA	Customer-outage-minutes avoided	41
32		POLE CRYSTAL_MT HOPE ROAD	170	17	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	44
33		POLE HOSPITAL_ELMWOOD	330	33	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	85
34		POLE DONTZ ROAD_KOTT ROAD	10	1	Poles	Pole Replacements	MANISTEE	Customer-outage-minutes avoided	3
35		POLE KENT CITY_TYRONE	410	41	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	105
36		POLE BARNARD_BAYSIDE	110	11	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	28
37		POLE STARKS_LEE POLE	140	14	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	36
38		POLE ITHACA_COURT HOUSE	600	60	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	154
39		POLE MARKEY_MONTYVILLE	60	6	Poles	Pole Replacements	ROSCOMMON	Customer-outage-minutes avoided	15
40		POLE SEVEN MILE_MAIDA	120	12	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	31
41		POLE NORTH KENT_FIVE MILE	10	1	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	3
42		POLE CLYDE ROAD_STATE ROAD	230	23	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	59
43		POLE ONEKAMA_ONEKAMA	740	74	Poles	Pole Replacements	MANISTEE	Customer-outage-minutes avoided	190
44		POLE LELAND_LELAND	320	32	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	82
45		POLE SNYDER_WELLSTON	10	1	Poles	Pole Replacements	MANISTEE	Customer-outage-minutes avoided	3
46		POLE PENINSULA_MAPLETON	690	69	Poles	Pole Replacements	GRAND TRAVERSE	Customer-outage-minutes avoided	177
47		POLE KENT CITY_CASNOVIA	360	36	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	93
48		POLE SEVEN MILE_QUARTERLINE	110	11	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	28
49		POLE ONEKAMA_BEAR LAKE	550	55	Poles	Pole Replacements	MANISTEE	Customer-outage-minutes avoided	141
50		POLE LAKE CITY_JENNINGS	140	14	Poles	Pole Replacements	MISSAUKEE	Customer-outage-minutes avoided	36
51		POLE GLEN LAKE_HOMESTEAD	130	13	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	33
52		POLE MAPLE CITY_SUGAR LOAF	70	7	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	18
53		POLE ONEKAMA_CHIEF	340	34	Poles	Pole Replacements	MANISTEE	Customer-outage-minutes avoided	87
54		POLE COGGINS_NEWBERG	120	12	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	31
55		POLE MAPLE CITY_CEDAR	800	80	Poles	Pole Replacements	LEELANAU	Customer-outage-minutes avoided	206
56		POLE PEACH RIDGE_KENOWA	120	12	Poles	Pole Replacements	OTTAWA	Customer-outage-minutes avoided	31
57		POLE TAWAS_TAWAS	270	27	Poles	Pole Replacements	IOSCO	Customer-outage-minutes avoided	69
58		POLE SHATTUCK_FOX GLEN	10	1	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	3
59		POLE MCGRAW_CASS	30	3	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	8
60		POLE GREENBUSH_HARRISVILLE POLE RUSH	20	2	Poles	Pole Replacements	ALCONA	Customer-outage-minutes avoided	5
61		**Pole Replacements Subtotal**	**11,080**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	POLE GREENBUSH_GREENBUSH RUSH	30	3	Poles	Pole Replacements	ALCONA	Customer-outage-minutes avoided	8
2		POLE 5 CHANNELS HYDRO_DISTR RUSH	30	3	Poles	Pole Replacements	IOSCO	Customer-outage-minutes avoided	8
3		POLE TAWAS_EAST TAWAS RUSH	10	1	Poles	Pole Replacements	IOSCO	Customer-outage-minutes avoided	3
4		POLE WEBB ROAD_HALE RUSH	60	6	Poles	Pole Replacements	IOSCO	Customer-outage-minutes avoided	15
5		POLE CHEYENNE_MCCARTY	70	7	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	18
6		POLE DAVENPORT_CONGRESS	120	12	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	31
7		POLE HACKETT_DICE ROAD	140	14	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	36
8		POLE SEIDEL_PLAZA	30	3	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	8
9		POLE BARNARD_BARNARD	10	1	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	3
10		POLE MCGRAW_PORTSMOUTH	110	11	Poles	Pole Replacements	BAY	Customer-outage-minutes avoided	28
11		POLE SEIDEL_BROCKWAY	60	6	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	15
12		POLE RYNO_MORENCI	20	2	Poles	Pole Replacements	OSCODA	Customer-outage-minutes avoided	5
13		POLE SMITH CREEK_WRIGHT	10	1	Poles	Pole Replacements	OGEMAW	Customer-outage-minutes avoided	3
14		POLE HARRIETTA_CABERFAE	20	2	Poles	Pole Replacements	WEXFORD	Customer-outage-minutes avoided	5
15		POLE TUSTIN_LUTHER	250	25	Poles	Pole Replacements	OSCEOLA	Customer-outage-minutes avoided	64
16		POLE SIMMONS_CABIN LAKE	70	7	Poles	Pole Replacements	OGEMAW	Customer-outage-minutes avoided	18
17		POLE HACKETT_HACKETT	140	14	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	36
18		POLE BLACK RIVER_ZEELAND	350	35	Poles	Pole Replacements	OTTAWA	Customer-outage-minutes avoided	90
19		POLE WOODLAND_BARNUM	180	18	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	46
20		POLE TUSTIN_LEROY	210	21	Poles	Pole Replacements	OSCEOLA	Customer-outage-minutes avoided	54
21		POLE MARION_MILL	200	20	Poles	Pole Replacements	OSCEOLA	Customer-outage-minutes avoided	51
22		POLE WOODWARD_PLEASANT LAKE	80	8	Poles	Pole Replacements	WEXFORD	Customer-outage-minutes avoided	21
23		POLE PRICE ROAD_MERIDIAN	250	25	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	64
24		POLE PRICE ROAD_PRICE	110	11	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	28
25		POLE CLYDE ROAD_GLENN ROAD	490	49	Poles	Pole Replacements	IONIA	Customer-outage-minutes avoided	126
26		POLE CHEBOYGAN_ALVERNO	290	29	Poles	Pole Replacements	CHEBOYGAN	Customer-outage-minutes avoided	75
27		POLE KELLOGGSVILLE_CHEMICAL	350	35	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	90
28		POLE SMALLWOOD DAM_WOODEN SHOE	60	6	Poles	Pole Replacements	GLADWIN	Customer-outage-minutes avoided	15
29		POLE TAMARACK_AMBLE	240	24	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	62
30		POLE RUTLAND_COOK RD	20	2	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	5
31		POLE MESICK_SPRINGVILLE	340	34	Poles	Pole Replacements	WEXFORD	Customer-outage-minutes avoided	87
32		POLE MIDDLEVILLE_LAFAYETTE	40	4	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	10
33		POLE HASTINGS_HANOVER	120	12	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	31
34		POLE WOODLAND_WOODBURY	20	2	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	5
35		POLE RUTLAND_TANNER LAKE	80	8	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	21
36		POLE BROGAN_SOUTH	60	6	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	15
37		POLE HASTINGS_BROADWAY	150	15	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	39
38		POLE DELTON_CLOVERDALE	60	6	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	15
39		POLE ANTRIM_ELK RAPIDS	280	28	Poles	Pole Replacements	ANTRIM	Customer-outage-minutes avoided	72
40		POLE BROGAN_BROGAN	170	17	Poles	Pole Replacements	BARRY	Customer-outage-minutes avoided	44
41		POLE CHEBOYGAN_SEYMOUR	70	7	Poles	Pole Replacements	CHEBOYGAN	Customer-outage-minutes avoided	18
42		POLE ANTRIM_BASS LAKE	150	15	Poles	Pole Replacements	ANTRIM	Customer-outage-minutes avoided	39
43		POLE BATES_ACME	90	9	Poles	Pole Replacements	GRAND TRAVERSE	Customer-outage-minutes avoided	23
44		POLE EAST JORDAN_WILLIAMS STREET	10	1	Poles	Pole Replacements	CHARLEVOIX	Customer-outage-minutes avoided	3
45		POLE STOCKBRIDGE_MORTON	160	16	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	41
46		POLE PARMA_PARMA	100	10	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	26
47		POLE PARMA_BALDWIN	70	7	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	18
48		POLE MICOR_LOSEY	40	4	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	10
49		POLE EAST JACKSON_DONNELY	30	3	Poles	Pole Replacements	JACKSON	Customer-outage-minutes avoided	8
50		POLE SYLVAN_CITY	200	20	Poles	Pole Replacements	WASHTENAW	Customer-outage-minutes avoided	51
51		POLE CENTRAL LAKE_CENTRAL LAKE	60	6	Poles	Pole Replacements	ANTRIM	Customer-outage-minutes avoided	15
52		POLE VIPOND_SPLAKE	10	1	Poles	Pole Replacements	KALKASKA	Customer-outage-minutes avoided	3
53		POLE BOYNE CITY_BOYNE CITY	30	3	Poles	Pole Replacements	CHARLEVOIX	Customer-outage-minutes avoided	8
54		POLE MANCELONA_LEETSVILLE	40	4	Poles	Pole Replacements	KALKASKA	Customer-outage-minutes avoided	10
55		POLE CENTRAL LAKE_ELLSWORTH	60	6	Poles	Pole Replacements	ANTRIM	Customer-outage-minutes avoided	15
56		POLE ALDEN_CLAM	160	16	Poles	Pole Replacements	KALKASKA	Customer-outage-minutes avoided	41
57		POLE KELLOGGSVILLE_HOME ACRES	160	16	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	41
58		POLE EDMORE_CEDAR LAKE	30	3	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	8
59		POLE EDMORE_SIX LAKES	70	7	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	18
60		POLE MANTON_GILBERT	960	96	Poles	Pole Replacements	WEXFORD	Customer-outage-minutes avoided	247
61		**Pole Replacements Subtotal**	**7,830**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	POLE ROSEBUSH_DELWIN	190	19	Poles	Pole Replacements	ISABELLA	Customer-outage-minutes avoided	49
2		POLE RIVERDALE_RIVERDALE	220	22	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	57
3		POLE TITUS LAKE_TENTH STREET	390	39	Poles	Pole Replacements	ALLEGAN	Customer-outage-minutes avoided	100
4		POLE FRANKENMUTH_MAIN STREET	100	10	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	26
5		POLE MORLEY_HOLLAND	70	7	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	18
6		POLE GILSON_ROCK LAKE	50	5	Poles	Pole Replacements	MONTCALM	Customer-outage-minutes avoided	13
7		POLE BAVARIAN_JEFFERSON	60	6	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	15
8		POLE ROEDEL ROAD_JUNCTION RD	190	19	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	49
9		POLE BAVARIAN_WEISS	20	2	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	5
10		POLE EAST GENESEE AVE_BAGLEY	220	22	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	57
11		POLE ROEDEL ROAD_BAKER	80	8	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	21
12		POLE PARKWAY_SOUTH CENTRAL	140	14	Poles	Pole Replacements	KALAMAZOO	Customer-outage-minutes avoided	36
13		POLE EAST GENESEE AVE_OUTER DRIVE	60	6	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	15
14		POLE WALNUT_GILKEY	320	32	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	82
15		POLE RANGER LAKE_LUPTON	70	7	Poles	Pole Replacements	IOSCO	Customer-outage-minutes avoided	18
16		POLE EAST GENESEE AVE_GENESEE	70	7	Poles	Pole Replacements	SAGINAW	Customer-outage-minutes avoided	18
17		POLE FORDYCE_LINCOLN	120	12	Poles	Pole Replacements	ISABELLA	Customer-outage-minutes avoided	31
18		POLE ISABELLA_PICKARD	20	2	Poles	Pole Replacements	ISABELLA	Customer-outage-minutes avoided	5
19		POLE CHEESMAN_MONROE	30	3	Poles	Pole Replacements	GRATIOT	Customer-outage-minutes avoided	8
20		POLE FOREST GROVE_OTTOGAN	360	36	Poles	Pole Replacements	OTTAWA	Customer-outage-minutes avoided	93
21		POLE ISABELLA_MISSION	40	4	Poles	Pole Replacements	ISABELLA	Customer-outage-minutes avoided	10
22		POLE FORDYCE_BAMBER	130	13	Poles	Pole Replacements	ISABELLA	Customer-outage-minutes avoided	33
23		POLE BYRON CENTER_BYRON CENTER	100	10	Poles	Pole Replacements	KENT	Customer-outage-minutes avoided	26
24		POLE JASPER_LAPORTE	140	14	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	36
25		POLE ISABELLA_REMUS	40	4	Poles	Pole Replacements	ISABELLA	Customer-outage-minutes avoided	10
26		POLE KIPP RD_COLLEGE RD	70	7	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	18
27		POLE SKYLARK_HILL	50	5	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	13
28		POLE PEWAMO_FOWLER	200	20	Poles	Pole Replacements	CLINTON	Customer-outage-minutes avoided	51
29		POLE MILBOURNE_DARTMOUTH	150	15	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	39
30		POLE MILBOURNE_DUPONT	70	7	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	18
31		POLE VAN ATTA_LEGG PARK	280	28	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	72
32		POLE VAN ATTA_POWELL	150	15	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	39
33		POLE BALLENGER_HOSPITAL	10	1	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	3
34		POLE SKYLARK_ROCKING CHAIR	120	12	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	31
35		POLE FIELD ROAD_PARKER CREEK	20	2	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	5
36		POLE HOGSBACK_PINE TREE	20	2	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	5
37		POLE CORUNNA_STATE RD	130	13	Poles	Pole Replacements	SHIAWASSEE	Customer-outage-minutes avoided	33
38		POLE CORUNNA_COURTHOUSE	110	11	Poles	Pole Replacements	SHIAWASSEE	Customer-outage-minutes avoided	28
39		POLE KIPP ROAD_COLUMBIA ROAD	80	8	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	21
40		POLE DUNHAM_FREEMAN	140	14	Poles	Pole Replacements	GENESEE	Customer-outage-minutes avoided	36
41		POLE LEVELY_STURGEON	220	22	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	57
42		POLE THORNTON_NIELSON RD	80	8	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	21
43		POLE THORNTON_WEST RIVER RD	190	19	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	49
44		POLE GLADWIN_CEDAR	30	3	Poles	Pole Replacements	GLADWIN	Customer-outage-minutes avoided	8
45		POLE WURTSMITH_AIR BASE	330	33	Poles	Pole Replacements	IOSCO	Customer-outage-minutes avoided	85
46		POLE CURTIS_MAGRUDDER	230	23	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	59
47		POLE LARKIN_EASTMAN	10	1	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	3
48		POLE BRADFORD_DISTRIBUTION	50	5	Poles	Pole Replacements	MIDLAND	Customer-outage-minutes avoided	13
49		POLE PEWAMO_PEWAMO POLE	20	2	Poles	Pole Replacements	CLINTON	Customer-outage-minutes avoided	5
50		POLE RED CEDAR_NORTHWIND POLE	10	1	Poles	Pole Replacements	INGHAM	Customer-outage-minutes avoided	3
51		POLE MT PLEASANT/BROADWAY	982	105	Poles	Pole Replacements	UNION	Customer-outage-minutes avoided	270
52		**Pole Replacements Subtotal**	**6,982**						
53		**LVD Lines Reliability Subtotal (Pole Replacements Total)**	**150,973**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
Page: 12 of 35
Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	RLBY HUBBARD LK_MILLER RD 681	429	1.1	Miles	Zonal Health Improvements	ALCONA	Customer-outage-minutes avoided	175,873
2		RLBY OTSEGO_FARMER 830 and 832	331	0.8	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	238,511
3		RLBY MARTIN_SHELBYVILLE LCP 212	116	0.4	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	14,278
4		RLBY MILL GROVE ALLEGAN HYDRO PULL POL	10	0.0	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	8,238
5		SYSP TITUS LAKE TENTH STREET	33	0.0	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	20,640
6		VOLT FENNVILLE_COMMERCIAL LCP SUB	41	0.3	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	2,047
7		PERRYMAN ST #1 SAUG ECNC RSU	25	0.0	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	9,810
8		RLBY SAUGATUCK-DOUGLAS LCP 140	468	0.6	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	391
9		GRID SALEM01	23	0.0	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	1,857
10		RLBY MANCELONA_ALBA LCP 083	131	0.5	Miles	Zonal Health Improvements	ANTRIM	Customer-outage-minutes avoided	36,170
11		RLBY SHANTY CREEK_LODGE	647	0.7	Miles	Zonal Health Improvements	ARENAC	Customer-outage-minutes avoided	14,536
12		RLBY DUQUITE_PINE RIVER LCP 253 ESIC OHL	99	0.3	Miles	Zonal Health Improvements	ARENAC	Customer-outage-minutes avoided	8,405
13		APPR HZD STANDISH_STANDISH LCP494	316	0.0	Miles	Zonal Health Improvements	ARENAC	Customer-outage-minutes avoided	6,400
14		LINDSEY RD ECNC RSO	10	0.0	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	1,000
15		RLBY WHITTEMORE_M-65 LCP 408	59	0.1	Miles	Zonal Health Improvements	BATTLE CREEK	Customer-outage-minutes avoided	804
16		RLBY WHITTEMORE_BEAR PAW LCP 28 OHL	81	0.0	Miles	Zonal Health Improvements	BATTLE CREEK	Customer-outage-minutes avoided	21,471
17		RLBY FRANKFORT_ELBERTA LCP 5415	95	0.0	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	275
18		RLBY Frankfort_Gateway LCP 5545	287	1.3	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	14,182
19		RLBY HOMESTEAD_BEULAH LCP 734	629	0.9	Miles	Zonal Health Improvements	BENZIE	Customer-outage-minutes avoided	76,439
20		KOLASSA_MATTESON LCP 706	257	0.9	Miles	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	1,749
21		RLBY BRONSON MILL ST 334 2,3,5	675	3.6	Miles	Zonal Health Improvements	BRANCH	Customer-outage-minutes avoided	7,670
22		15 MILE ROAD_15 MI LCP 006 PH3 ESIC OHL	24	0.0	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	733
23		RLBY20 PRINCETON BROWNLEE FIRST ZONE DEM	24	0.0	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	16,433
24		FUSE GOGUAC_LAKEVIEW	7	0.0	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	28,429
25		GRID Goguac01	70	0.0	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	331,440
26		RLBY BEADLE SPAULDING 257 PT2	237	0.3	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	113,460
27		VOLT 048204-6571 ORCHARD BEACH DR	15	1.0	Miles	Zonal Health Improvements	CHEBOYGAN	Customer-outage-minutes avoided	501
28		VOLT MANNSIDING CEDAR LCP 462	125	0.6	Miles	Zonal Health Improvements	CLARE	Customer-outage-minutes avoided	320
29		RLBY DEER LAKE BALL AVE LCP 794	354	1.1	Miles	Zonal Health Improvements	CLARE	Customer-outage-minutes avoided	40,650
30		RLBY HARRISON STOCKWELL LCP 129	308	1.0	Miles	Zonal Health Improvements	CLARE	Customer-outage-minutes avoided	77,301
31		RLBY CONVIS_CONVIS LCP 363	349	0.8	Miles	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	22,876
32		13 MILE RD RSO	20	0.0	Miles	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	1,000
33		RLBY OLIVET COLLEGE 149	94	0.4	Miles	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	3,449
34		ASSYRIA HWY. RLBY RSU	18	0.0	Miles	Zonal Health Improvements	EATON	Customer-outage-minutes avoided	851
35		RLBY MACKINAW CITY_STATE PARK LCP SUB	613	0.7	Miles	Zonal Health Improvements	EMMET	Customer-outage-minutes avoided	20,252
36		VOLT KEARSLEY_COVERT ROAD LCP 793	53	0.1	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	1,000
37		RLBY FOURTEENTH-SOUTHWESTERN ATR LOOP	508	0.6	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	1,746
38		VOLT STANLEY_SUMMIT LCP SUB	283	0.5	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	52,170
39		VOLT Mayfair/Cass	142	0.0	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	33,147
40		VOLT LEITH STREET_WESTERN ROAD LCP 011	171	0.0	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	10,870
41		VOLT MONTROSE_MCKINLEY ROAD LCP SUB	75	0.0	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	496
42		RLBY GLADWIN BUZZELL LCP 309	243	0.8	Miles	Zonal Health Improvements	GLADWIN	Customer-outage-minutes avoided	452
43		FUSE GLADWIN_RURAL	188	0.0	Miles	Zonal Health Improvements	GLADWIN	Customer-outage-minutes avoided	124,884
44		RLBY WIRTZ ROAD_WILDWOOD LCP 309	791	3.0	Miles	Zonal Health Improvements	GLADWIN	Customer-outage-minutes avoided	135,032
45		RLBY Silver Lake Secor LCP 5452	361	0.8	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	84,818
46		HZRD PENINSULA-MCKINLEY ROAD LCP 535	37	0.1	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	39,672
47		HZRD PENINSULA-MAPLETON LCP 7938	49	0.1	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	180
48		HZRD PENINSULA-MAPLETON LCP 796	125	0.7	Miles	Zonal Health Improvements	GRAND TRAVERSE	Customer-outage-minutes avoided	47,480
49		FUSE MIDDLETON_NEWARK	154	0.0	Miles	Zonal Health Improvements	GRATIOT	Customer-outage-minutes avoided	21,008
50		VOLT STURGEON_ST ANDREWS LCP 0030	26	0.3	Miles	Zonal Health Improvements	GRATIOT	Customer-outage-minutes avoided	25,566
51		RLBY JONESVILLE_MILNES LCP 390	307	0.4	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	44,917
52		FUSE LITCHFIELD_ADAMS RD	42	0.0	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	1,000
53		CAMDEN_MONTGOMERY PHASE SWAPS	13	0.0	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	310
54		CAMDEN_CAMDEN 1ST ZONE REBUILD	268	0.9	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	63,831
55		RLBY CAMDEN_CAMDEN LCP 153J	180	0.5	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	91,632
56		RLBY NORTH LANSING_LABORATORY LCP 027	62	0.9	Miles	Zonal Health Improvements	INGHAM	Customer-outage-minutes avoided	6,091
57		RLBY15 DIMONDALE-DIMONDALE	945	1.6	Miles	Zonal Health Improvements	INGHAM	Customer-outage-minutes avoided	128,146
58		RLBY HARPER ROAD_ARENS LCP 363	1,316	0.5	Miles	Zonal Health Improvements	INGHAM	Customer-outage-minutes avoided	271,366
59		RLBY15 BATTEESE/MUNITH 10832 Waterloo-Mu	13	0.0	Miles	Zonal Health Improvements	INGHAM	Customer-outage-minutes avoided	263
60		RLBY TURNER_GATES LCP 783	205	1.5	Miles	Zonal Health Improvements	IOSCO	Customer-outage-minutes avoided	36,712
61		RLBY SHERMAN_SHERMAN 324	506	0.8	Miles	Zonal Health Improvements	IOSCO	Customer-outage-minutes avoided	13,840
62		RLBY FIVE CHANNELS HYDRO - NEW SUB	888	0.2	Miles	Zonal Health Improvements	IOSCO	Customer-outage-minutes avoided	23,153
63		RLBY COOKE DAM/SUB MONUMENT ESIC	32	0.2	Miles	Zonal Health Improvements	IOSCO	Customer-outage-minutes avoided	640
64		RLBY FOOTE HYDRO_REA RD SUB (NEW)	133	0.2	Miles	Zonal Health Improvements	IOSCO	Customer-outage-minutes avoided	22,910
65		VOLT MT PLEASANT_BROADWAY LCP 431	37	0.0	Miles	Zonal Health Improvements	ISABELLA	Customer-outage-minutes avoided	646
66		VOLT Mt Pleasant_Broadway LCP 011	51	2.9	Miles	Zonal Health Improvements	ISABELLA	Customer-outage-minutes avoided	109,201
67		GRID AUTO PARNALL SUB WEATHER STATION	13	0.0	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	0
68		RLBY WILDWOOD_MACKLIN SUB	166	0.3	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	199,440
69		RLBY SPRING ARBOR_ARBOR HILLS	129	0.2	Miles	Zonal Health Improvements	JACKSON	Customer-outage-minutes avoided	2,418
70		RLBY WARNER_BURCHETT LCP CKT_LCP320	1,793	3.6	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	2,529,293
71		**Zonal Health Improvements Subtotal**	**17,323**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	RLBY18 Alder Creek - E Leroy LCP 614	383	1.0	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	131,744
2		RLBY Alder Creek - E Leroy LCP 661	372	1.3	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	129,460
3		RLBY YORKVILLE_BAYVIEW LCP 144 Part2	640	2.2	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	131,283
4		RLBY AUGUSTA-AUGUSTA LCP 596	1,153	1.4	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	77,678
5		GRID RIDGEVIEW01_GALESBURG01	24	0.0	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	282,960
6		VOLT PARKWAY_VINE 1408	145	0.8	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	2,810
7		FUSE STADIUM_COLLEGE LCP 304 1	10	0.0	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	412
8		VOLT PARKWAY_VINE	201	0.0	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	224
9		RLBY Alden_Clam LCP 7009 Master	145	0.3	Miles	Zonal Health Improvements	KALKASKA	Customer-outage-minutes avoided	408,676
10		VOLT MOLINE_MOLINE TLM	124	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	1,000
11		RLBY LABARGE ALASKA 68th St LCP 208 1-12	293	1.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	148,551
12		RLBY Meadowbrooke Cherry LCP 464	128	0.6	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	125,442
13		RLBY Foreman Vergennes LCP 673	376	0.6	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	39,941
14		RLBY KRAFT AVENUE/TAHOE. LCP 260	138	0.3	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	13,206
15		RLBY BRETON-PLYMOUTH LCP 484	204	0.3	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	83,028
16		VOLT DoehlerJarvis_	209	0.4	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	85,063
17		RLBY BRETON_TOWERS LCP SUB	172	0.1	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	110,000
18		VOLT BOWEN_KIMBERLY TLM 0611201102	53	0.2	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	70,348
19		RLBY Kelloggsvl LCP 084	352	0.4	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	143,264
20		Failure UG Lines Parkway Ave	10	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	407
21		VOLT BEALS RD_CLYDE PARK TLM 0612112106	164	0.1	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	83,148
22		VOLT McKee Ave SW Low Voltage	110	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	33,770
23		VOLT OHS 26th St SW Wyoming	10	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	4,029
24		VOLT 3268 Clyde Park Ave SW Low Voltage	70	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	860
25		VOLT HANSEN-HANSEN TLM 4207	85	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	595
26		VOLT HANSEN-HANSEN TLM 4301	71	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	345
27		RLBY PARAMOUNT-NORTHLAND FARMS LCP	615	1.6	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	827,368
28		RLBY ABERDEEN_HOLLYWOOD LCP 755	151	0.2	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	306,869
29		RLBY Knapp/Perkins LCP 86	690	1.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	313,000
30		RLBY LEFINGWEL_BRADFORDEB	422	0.5	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	213,954
31		VOLT Leonard_Taylor	181	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	312
32		RLBY HARVEY_CORRECTION SUB	48	0.1	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	32,171
33		VOLT HARVEY STREET_DIAMOND TLM0711293101	53	0.3	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	26,871
34		HARVEY_FULLER TLM 0711294410	107	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	435
35		FUSE RAMONA_BLODGETT	105	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	549
36		RLBY HASKELITE_ANN STREET LCP CKT	32	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	76,464
37		GRID WEALTHY ST01_WEALTHY08	29	0.6	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	289,680
38		GRID WEALTHY ST01_STANDALE01	20	0.0	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	1,091
39		VOLT Wealthy St_Indiana	193	0.1	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	97,851
40		RLBY CANNONSBURG-GRASS LAKE SUNFISH L	168	0.3	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	85,176
41		RLBY Bella Vista/Blakely LCP-545	634	2.1	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	143,229
42		RLBY CANONSBURG_WEST CANNON LCP-317	709	0.8	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	16,742
43		RLBY ENGLISHVILLE/PINE ISL LCP505	462	0.9	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	28,299
44		RLBY Rockford/Summit LCP-565	354	0.5	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	265,445
45		RLBY HULL STREET--LIME LAKE LCP814	442	0.9	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	34,397
46		RLBY ROCKFORD_SUMMIT SUB	558	0.9	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	604,770
47		RLBY CDR SPRING_EDGERTON LCP 814	489	1.3	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	115,264
48		RLBY Cedar Springs-White Creek LCP 902	218	0.3	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	123,754
49		APPR RLBYCEDAR SPRINGS_NELSONLCP179	629	0.8	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	459,565
50		RLBY CDR Springs WhiteCreek LCP810	412	0.9	Miles	Zonal Health Improvements	KENT	Customer-outage-minutes avoided	234,815
51		HZRD MAPLE CITY-CEDAR E BODUS RD	349	1.1	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	2,156
52		RLBY Northport Lighthouse LCP 598 Part AB	595	1.1	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	116,584
53		HZRD NORTHPORT_LIGHTHOUSE LCP 6055	50	0.2	Miles	Zonal Health Improvements	LEELANAU	Customer-outage-minutes avoided	16,244
54		HZRD HIGH BRIDGE-CREAMERY LCP 410	33	0.2	Miles	Zonal Health Improvements	MANISTEE	Customer-outage-minutes avoided	2,730
55		RLBY ARCADIA-STARKE LCP 553 Part 12	550	1.9	Miles	Zonal Health Improvements	MANISTEE	Customer-outage-minutes avoided	9,155
56		RLBY CHAUVEZ PARK LCP 302	838	2.7	Miles	Zonal Health Improvements	MASON	Customer-outage-minutes avoided	74,732
57		HZRD Remus-Mecosta LCP 707	493	1.4	Miles	Zonal Health Improvements	MECOSTA	Customer-outage-minutes avoided	123,711
58		RLBY Bradford Distribution LCP 372	65	0.3	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	24,513
59		RLBY Camelot Lake Loomis LCP 182	450	0.8	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	47,922
60		RLBY Camelot Lake Loomis LCP 132	615	1.0	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	71,438
61		RLBY PRICE ROAD_PRICE LCP 0031	430	0.7	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	49,587
62		RLBY EASTLAWN_FLAJOLE LCP 0338	242	0.4	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	122,585
63		FUSE ASHMAN CIRCLE_ASHMAN	342	0.0	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	17,296
64		RLBY Thornton_Nelson LCP 093J	450	1.0	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	16,266
65		RLBY Curtis Magrudder LCP 247 TW	438	1.0	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	71,127
66		RLBY SANDERSON_COUNTY FARM LCP 414	194	0.4	Miles	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	126,259
67		RLBY CRYSTAL_CRYSTAL RD 468	717	1.5	Miles	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	113,656
68		RLBY PECK ROAD_WISE ROAD LCP SUB ALL	2,660	5.6	Miles	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	8,500
69		RLBY MCCRACKEN_LEON LCP 365	363	0.5	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	9,600
70		RLBY EAST MUSKEGON_QUARTERLINE LCP 681	46	0.5	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	12,161
71		RLBY WESTERN AVENUE LCP 168 1-30	419	0.7	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	47,160
72		VOLT SPRING DRIVE_BISHOP LAKE LCP sub	200	0.0	Miles	Zonal Health Improvements	NEWAYGO	Customer-outage-minutes avoided	34,200
73		RLBY ALGER_FOREST LK	165	0.7	Miles	Zonal Health Improvements	OGEMAW	Customer-outage-minutes avoided	16,485
74		RLBY MARION-GASCOM LCP 063	86	0.1	Miles	Zonal Health Improvements	OSCEOLA	Customer-outage-minutes avoided	150,733
75		RLBY REED CITY_MEDICAL LCP 668	387	0.4	Miles	Zonal Health Improvements	OSCEOLA	Customer-outage-minutes avoided	24,040
76		RLBY RANGER LAKE_GOODAR LCP 158	318	1.0	Miles	Zonal Health Improvements	OSCODA	Customer-outage-minutes avoided	172,633
77		WLDFRE ABBE_HWY33 LCP 198 ALL	2,633	9.0	Miles	Zonal Health Improvements	OSCODA	Customer-outage-minutes avoided	207,005
78		RLBY MURNER_VAN TYLE OROURKE BLVD	1,185	0.0	Miles	Zonal Health Improvements	OTSEGO	Customer-outage-minutes avoided	34,320
79		**Zonal Health Improvements Subtotal**	**28,677**						
80		**LVD Lines Reliability Subtotal (Zonal Health Total)**	**46,000**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Lines Reliability - LVD	SCDY CEDAR SPRINGS_EDGERTON	484	0.95	Miles	2.01 Targeted Circuit Improvements - Secondary	North Kent	Service Quality; Customers	67
2		SCDY COLLEGE PARK_MADISON	496	0.79	Miles	2.01 Targeted Circuit Improvements - Secondary	Adrian	Service Quality; Customers	1167
3		SCDY EASTWOOD_TEXEL	810	3.84	Miles	2.01 Targeted Circuit Improvements - Secondary	Kalamazoo	Service Quality; Customers	498
4		SCDY ELEVENTH STREET_BASELINE	182	0.9	Miles	2.01 Targeted Circuit Improvements - Secondary	Kalamazoo	Service Quality; Customers	62
5		SCDY ELM STREET_PORTER	2,561	9.61	Miles	2.01 Targeted Circuit Improvements - Secondary	Battle Creek	Service Quality; Customers	1,286
6		SCDY ELM STREET_VERONA	5,803	16.35	Miles	2.01 Targeted Circuit Improvements - Secondary	Battle Creek	Service Quality; Customers	3,277
7		SCDY EMERALD_BANBURY	1	0.01	Miles	2.01 Targeted Circuit Improvements - Secondary	Kalamazoo	Service Quality; Customers	1
8		SCDY KEATING_WOOD STREET	675	1.08	Miles	2.01 Targeted Circuit Improvements - Secondary	Muskegon	Service Quality; Customers	268
9		SCDY KENDALL_WESTWOOD	568	6.19	Miles	2.01 Targeted Circuit Improvements - Secondary	Kalamazoo	Service Quality; Customers	938
10		SCDY KINDERHOOK_GILEAD	104	1.36	Miles	2.01 Targeted Circuit Improvements - Secondary	Coldwater	Service Quality; Customers	297
11		SCDY LEVEL PARK_LEVEL PARK	220	0.97	Miles	2.01 Targeted Circuit Improvements - Secondary	Battle Creek	Service Quality; Customers	61
12		SCDY LIBERTY_WASHINGTON	2,148	7.38	Miles	2.01 Targeted Circuit Improvements - Secondary	Battle Creek	Service Quality; Customers	599
13		SCDY LOMBARD_SHERIDAN	1,414	2.53	Miles	2.01 Targeted Circuit Improvements - Secondary	Battle Creek	Service Quality; Customers	1064
14		SCDY MAPLE GROVE_HENRY STREET	76	0.5	Miles	2.01 Targeted Circuit Improvements - Secondary	Muskegon	Service Quality; Customers	31
15		SCDY MAPLE GROVE_SUMMIT AVENUE	873	5.02	Miles	2.01 Targeted Circuit Improvements - Secondary	Muskegon	Service Quality; Customers	551
16		SCDY MCCRACKEN_SHERMAN	44	0.14	Miles	2.01 Targeted Circuit Improvements - Secondary	Muskegon	Service Quality; Customers	30
17		SCDY MICHIGAN_LOOKOUT	104	0.39	Miles	2.01 Targeted Circuit Improvements - Secondary	Grand Rapids	Service Quality; Customers	32
18		SCDY MUSKEGON HEIGHTS_E CENTRAL	90	0.22	Miles	2.01 Targeted Circuit Improvements - Secondary	Muskegon	Service Quality; Customers	4
19		SCDY ORIOLE_WHITTIER	543	1.2	Miles	2.01 Targeted Circuit Improvements - Secondary	Ludington	Service Quality; Customers	144
20		SCDY OSHTEMO_HURD	40	0.15	Miles	2.01 Targeted Circuit Improvements - Secondary	Kalamazoo	Service Quality; Customers	13
21		SCDY PHILLIPS_MILWOOD	616	2.04	Miles	2.01 Targeted Circuit Improvements - Secondary	Kalamazoo	Service Quality; Customers	311
22		SCDY PISTON RING_STATE	484	0.95	Miles	2.01 Targeted Circuit Improvements - Secondary	North Kent	Service Quality; Customers	90
23		SCDY SUMMIT_FRANCIS STREET	944	5.31	Miles	2.01 Targeted Circuit Improvements - Secondary	Jackson	Service Quality; Customers	1,100
24		SCDY SUMMIT_SOUTH STREET	643	3.54	Miles	2.01 Targeted Circuit Improvements - Secondary	Jackson	Service Quality; Customers	394
25		**LVD Lines Reliability Subtotal (Secondary Total)**	**19,922**						
26	Lines Reliability - LVD	UINJ Cable Rejuvenation Flint	2,480	6.00	Miles	Underground Cable Rejuvenation	Flint Area	Customer-outage-minutes avoided	58,370
27		UINJ Cable Rejuvenation Grand Rapids	10,485	10.00	Miles	Underground Cable Rejuvenation	Grand Rapids Area	Customer-outage-minutes avoided	644,781
28		UINJ Cable Rejuvenation Traverse City	11,415	10.00	Miles	Underground Cable Rejuvenation	Traverse City Area	Customer-outage-minutes avoided	507,569
29		**LVD Lines Reliability Subtotal (Underground Cable Total)**	**24,380**						
30	Lines Reliability - LVD	RLBY CHEBOYGAN-SEYMOUR LCP 250	931	2.5	Miles	Voltage Conversions	CHEBOYGAN	Customer-outage-minutes avoided	78,764
31		RLBY PRESCOTT_MAPLE RIDGE	471	1.0	Miles	Voltage Conversions	OGEMAW	Customer-outage-minutes avoided	1,369,230
32		RLBY RYNO_MAPES SUB	2,322	3.8	Miles	Voltage Conversions	OSCODA	Customer-outage-minutes avoided	237,191
33		RLBY GERRISH SUB VOLTAGE CONVERSION	4,907	9.3	Miles	Voltage Conversions	CLINTON	Customer-outage-minutes avoided	949,014
34		RLBY EIGHT POINT LK GEORGE	1,004	3.0	Miles	Voltage Conversions	OSCEOLA	Customer-outage-minutes avoided	254,911
35		RLBY EDMORE/CEDAR LAKE VOLT CONV	3,821	15.0	Miles	Voltage Conversions	MONTCALM	Customer-outage-minutes avoided	200,000
36		RLBY CONVIS_CONVIS 304 PART B	243	0.4	Miles	Voltage Conversions	EATON	Customer-outage-minutes avoided	220,654
37		RLBY NOBLE_WHITNEY	1,368	5.1	Miles	Voltage Conversions	ARENAC	Customer-outage-minutes avoided	73,885
38		RLBY STANWOOD-RIVERSWAY	2,857	12.0	Miles	Voltage Conversions	NEWAYGO	Customer-outage-minutes avoided	525,008
39		VOLT STATE STREET_MACKINAW LCP 684J	113	0.3	Miles	Voltage Conversions	SAGINAW	Customer-outage-minutes avoided	27,960
40		DtoY VANDERBILT_CORWITH LCP 248	122	0.3	Miles	Voltage Conversions	OTSEGO	Customer-outage-minutes avoided	17,801
41		RLBY LABARGE ALASKA 68th St LCP208 13-24	352	0.3	Miles	Voltage Conversions	KENT	Customer-outage-minutes avoided	246,982
42		RLBY LAKE ODESSA LAKE LCP 585	242	0.5	Miles	Voltage Conversions	IONIA	Customer-outage-minutes avoided	100,871
43		RLBY MAUMEE_MAPLE ST LCP 028	248	1.0	Miles	Voltage Conversions	LENAWEE	Customer-outage-minutes avoided	13,356
44		DTOY SCOTTVILLE_SCOTTVILLE 656B	2,472	0.5	Miles	Voltage Conversions	MASON	Customer-outage-minutes avoided	31,956
45		RLBY Standwood-Tyler Rd	193	1.9	Miles	Voltage Conversions	MECOSTA	Customer-outage-minutes avoided	3,409
46		RLBY PIGEON LAKE_PIGEON LCP 146 PT4	188	1.7	Miles	Voltage Conversions	OTTAWA	Customer-outage-minutes avoided	80,336
47		VOLT PLAINWELL_HEIGHTS	433	3.8	Miles	Voltage Conversions	ALLEGAN	Customer-outage-minutes avoided	2,493
48		RLBY-VC-CARY RD_WOODSTOCK	2,049	17.4	Miles	Voltage Conversions	LENAWEE	Customer-outage-minutes avoided	106,170
49		DtoY VANDERBILT_WOLVERINE LCP 490	816	3.9	Miles	Voltage Conversions	OTSEGO	Customer-outage-minutes avoided	5,656
50		RLBY AU GRES_AU GRES	522	1.9	Miles	Voltage Conversions	TAWAS	Customer-outage-minutes avoided	98,370
51		RLBY WOODWAR-PLEASANT LK	488	0.8	Miles	Voltage Conversions	WEXFORD	Customer-outage-minutes avoided	4,448
52		RLBY WURTSMITH_MISSION LCP 686 (Part 1 and 3)	2,025	4.3	Miles	Voltage Conversions	TAWAS	Customer-outage-minutes avoided	133,645
53		RLBY GERRISH/LEGION SUB VOLTAGE CONVERT	2,600	19.0	Miles	Voltage Conversions	WEST BRANCH	Customer-outage-minutes avoided	258,450
54		RLBY GERRISH/GOLF CLUB SUB VOLT CONVERT	950	5.0	Miles	Voltage Conversions	WEST BRANCH	Customer-outage-minutes avoided	584,985
55		DTOY SCOTTVILLE_US-31 LCP 222	671	7.9	Miles	Voltage Conversions	SHERMAN	Customer-outage-minutes avoided	0
56		VOLT PELLSTON_DISTRIBUTION LCP 301	1,297	2.8	Miles	Voltage Conversions	BOYNE	Customer-outage-minutes avoided	28,700
57		VOLT FLETCHER_ODEN LCP 082	239	0.3	Miles	Voltage Conversions	BOYNE	Customer-outage-minutes avoided	4,789
58		DTOY CHEBOYGAN_ALVERNO GALBRAITH	232	1.5	Miles	Voltage Conversions	CHEBOYGAN	Customer-outage-minutes avoided	0
59		DTOY CHEBOYGAN_ALVERNO HENNINGS	840	4.0	Miles	Voltage Conversions	CHEBOYGAN	Customer-outage-minutes avoided	1,527
60		DTOY CHEBOYGAN_ALVERNO M33	213	2.0	Miles	Voltage Conversions	CHEBOYGAN	Customer-outage-minutes avoided	0
61		DTOY CHEBOYGAN_ALVERNO ORCHARD BEACH	1,512	10.0	Miles	Voltage Conversions	CHEBOYGAN	Customer-outage-minutes avoided	1,198,166
62		DTOY CHEBOYGAN_ALVERNO ST ANTOINE	969	6.6	Miles	Voltage Conversions	CHEBOYGAN	Customer-outage-minutes avoided	1,205
63		DtoY BESSINGER_QUARRY LCP SUB	1,825	12	Miles	Voltage Conversions	WEST BRANCH	Customer-outage-minutes avoided	221,691
64		**LVD Lines Reliability Subtotal (Voltage Conversions Subtotal)**	**39,534**						

MICHIGAN PUBLIC SERVICE COMMISSION
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Bridge Period LVD Project List
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($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	EXIT BARNARD/HOSPITAL	215	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
2		RLBY Wyoming Park SUB Exit SW 01 CKT	37	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
3		EXIT PORTSMOUTH/INDIANTOWN	61	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
4		THDPY19 HUDSONVILLE SUB EXITS	100	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
5		EXIT LEONARD_IONIA & TAYLOR	37	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
6		EXIT HUBBARD LAKE_SUB	11	1	Project	Circuit Exit Projects	ALCONA	Increase Safety by Installing Isolation Point	-
7		EXIT GRANDVILLE SUB EXIT SWITCHES	90	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
8		EXIT COGGINS_ALMEDA	79	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
9		EXIT HOTCHKISS_BAY VALLEY	24	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
10		EXIT HURON_TWO MILE	57	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
11		EXIT CENTREVILLE	7	1	Project	Circuit Exit Projects	ST JOSEPH	Increase Safety by Installing Isolation Point	-
12		EXIT BARNUM	19	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
13		EXIT OLIVET	20	1	Project	Circuit Exit Projects	EATON	Increase Safety by Installing Isolation Point	-
14		EXIT TEKONSHA	15	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
15		EXIT BEHNKE	15	1	Project	Circuit Exit Projects	BRANCH	Increase Safety by Installing Isolation Point	-
16		EXIT BRYE RD SUB SUB EXIT SWITCHES	15	1	Project	Circuit Exit Projects	MASON	Increase Safety by Installing Isolation Point	-
17		EXIT BALDWIN SUB SUB EXIT SWITCHES	43	1	Project	Circuit Exit Projects	LAKE	Increase Safety by Installing Isolation Point	-
18		EXIT HART DISTRIBUTION SUB EXIT SW	15	1	Project	Circuit Exit Projects	OCEANA	Increase Safety by Installing Isolation Point	-
19		EXIT MANTON SUB EXIT SWITCHES	62	1	Project	Circuit Exit Projects	WEXFORD	Increase Safety by Installing Isolation Point	-
20		EXIT TUSTIN SUB EXIT SWITCHES	52	1	Project	Circuit Exit Projects	OSCEOLA	Increase Safety by Installing Isolation Point	-
21		EXIT BOON ROAD SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	WEXFORD	Increase Safety by Installing Isolation Point	-
22		EXIT MIDLAND_COMMERCIAL	11	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
23		EXIT TAWAS_TAWAS	10	1	Project	Circuit Exit Projects	IOSCO	Increase Safety by Installing Isolation Point	-
24		EXIT RIVERDALE_BOTH CIRCUITS	12	1	Project	Circuit Exit Projects	GRATIOT	Increase Safety by Installing Isolation Point	-
25		EXIT ASHMAN CIRCLE_ASHMAN	27	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
26		EXIT ASHMAN CIRCLE_HIGH SCHOOL	12	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
27		EXIT JASPER_BOTH CIRCUITS	35	1	Project	Circuit Exit Projects	MIDLAND	Increase Safety by Installing Isolation Point	-
28		EXIT MCBAIN SUB EXIT SWITCHES	21	1	Project	Circuit Exit Projects	MISSAUKEE	Increase Safety by Installing Isolation Point	-
29		EXIT MESICK SUB EXIT SWITCHES	19	1	Project	Circuit Exit Projects	WEXFORD	Increase Safety by Installing Isolation Point	-
30		EXIT HARING SUB EXIT SWITCHES	39	1	Project	Circuit Exit Projects	WEXFORD	Increase Safety by Installing Isolation Point	-
31		EXIT LAKE MITCHELL SUB EXIT SWITCHES	25	1	Project	Circuit Exit Projects	WEXFORD	Increase Safety by Installing Isolation Point	-
32		EXIT AU GRES_POINT LOOK-OUT	19	1	Project	Circuit Exit Projects	ARENAC	Increase Safety by Installing Isolation Point	-
33		EXIT DUQUITE_JOHNSFIELD	40	1	Project	Circuit Exit Projects	ARENAC	Increase Safety by Installing Isolation Point	-
34		EXIT ROSEBUSH_STEVENSON LAKE	64	1	Project	Circuit Exit Projects	ISABELLA	Increase Safety by Installing Isolation Point	-
35		EXIT SURREY_MAIN STREET	42	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
36		EXIT GLADWIN_SPRING	13	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	-
37		EXIT GLADWIN_BUZZELL	13	1	Project	Circuit Exit Projects	GLADWIN	Increase Safety by Installing Isolation Point	-
38		EXIT HARRISON_HARRISON	11	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
39		EXIT HARRISON_STOCKWELL	13	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
40		EXIT HARRISON_DODGE CITY	21	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
41		EXIT BOSTON SQUARE/MULICK PARK CKT 4	47	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
42		EXIT TOWN LINE_MACKINAW	40	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
43		EXIT PINCONNING_PINCONNING	40	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
44		EXIT CARROLLTON/CARROLLTON	67	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
45		EXIT CHEYENNE_CKT 3,5,6 UG	101	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
46		EXIT CHEYENNE_CKT 1,2,4 OH	44	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
47		EXIT DAVENPORT_CONGRESS	49	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
48		EXIT ST HELEN SUB EXIT SWITCHES	48	1	Project	Circuit Exit Projects	ROSCOMMON	Increase Safety by Installing Isolation Point	-
49		EXIT ROSCOMMON SUB EXIT SWITCHES	30	1	Project	Circuit Exit Projects	ROSCOMMON	Increase Safety by Installing Isolation Point	-
50		EXIT FREELAND - BOTH CIRCUITS	26	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
51		EXIT SHATTUCK/FOX GLEN	156	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
52		EXIT SOUTH WASHINGTON/FORDNEY	75	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
53		EXIT ST CHARLES/SAGINAW	55	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
54		EXIT KOCHVILLE_ALL CKTS	13	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
55		EXIT20 PICKEREL-INDIAN LAKE	108	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
56		Exit Red Arrow	31	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
57		EXIT DUNBAR SUB	41	1	Project	Circuit Exit Projects	MONROE	Increase Safety by Installing Isolation Point	-
58		EXIT LASALLE SUB	32	1	Project	Circuit Exit Projects	MONROE	Increase Safety by Installing Isolation Point	-
59		EXIT RANKIN-ALL CKTS	67	1	Project	Circuit Exit Projects	GENESEE	Increase Safety by Installing Isolation Point	-
60		EXIT EAST BAY SUB EXIT SWITCHES	17	1	Project	Circuit Exit Projects	GRAND TRAVERSE	Increase Safety by Installing Isolation Point	-
61		EXITS Columbia	34	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
62		EXIT Bedford	22	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
63		EXIT Harlem Sub	99	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
64		EXIT MANCELONA SUB	34	1	Project	Circuit Exit Projects	ANTRIM	Increase Safety by Installing Isolation Point	-
65		EXIT BEECHER	25	1	Project	Circuit Exit Projects	LENAWEE	Increase Safety by Installing Isolation Point	-
66		EXIT DIETZ ROAD SUB	77	1	Project	Circuit Exit Projects	CHARLEVOIX	Increase Safety by Installing Isolation Point	-
67		EXIT STOCKBRIDGE	51	1	Project	Circuit Exit Projects	INGHAM	Increase Safety by Installing Isolation Point	-
68		EXIT UG VILLAGE GREEN CKT 1 EXIT A	15	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
69		EXIT PALMER	85	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
70		EXIT DIMONDALE	147	1	Project	Circuit Exit Projects	EATON	Increase Safety by Installing Isolation Point	-
71		EXIT ST JOHNS	47	1	Project	Circuit Exit Projects	CLINTON	Increase Safety by Installing Isolation Point	-
72		EXIT OVID	17	1	Project	Circuit Exit Projects	CLINTON	Increase Safety by Installing Isolation Point	-
73		EXIT WATERTOWN	21	1	Project	Circuit Exit Projects	CLINTON	Increase Safety by Installing Isolation Point	-
74		EXIT WESTPHALIA	28	1	Project	Circuit Exit Projects	CLINTON	Increase Safety by Installing Isolation Point	-
75		EXIT PERRY	18	1	Project	Circuit Exit Projects	SHIAWASSEE	Increase Safety by Installing Isolation Point	-
76		EXIT POTTERVILLE	21	1	Project	Circuit Exit Projects	EATON	Increase Safety by Installing Isolation Point	-
77		EXIT WINGATE	55	1	Project	Circuit Exit Projects	WASHTENAW	Increase Safety by Installing Isolation Point	-
78		RLBY Wyoming Park SUB Exit SW 02 CKT	15	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
79		EXIT ESSEXVILLE EXITS_ALL CKTS	177	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
80		HOUGHTON HEIGHTS NEW SUB EXIT	218	1	Project	Circuit Exit Projects	ROSCOMMON	Increase Safety by Installing Isolation Point	-
81		EXIT LEFFINGWELL/ALL CKTS EXIT DIS	210	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
82		EXIT ENGLISHVILLE_PINE ISLAND SUB EXIT	36	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
83		EXIT Stanton_Dickerson Lake-Stanton	82	1	Project	Circuit Exit Projects	MONTCALM	Increase Safety by Installing Isolation Point	-
84		EXIT JACKMAN SUB 1-6 & 3-6	21	1	Project	Circuit Exit Projects	MONROE	Increase Safety by Installing Isolation Point	-
85		EXIT HALEY ROAD	13	1	Project	Circuit Exit Projects	LENAWEE	Increase Safety by Installing Isolation Point	-
86		**LVD Lines Reliability Subtotal (Circuit Exits Total)**	**4,090**						

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($000)

Case No.: U-22070
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Page: 16 of 35
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Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	DISTA HARVEY ST06_RAMONA01	4	1	Loop	Automation - ATR Loops	GRA	Customer-outage-minutes-avoided	366,840
2		DISTA QUINCY01_QUINCY03	4	1	Loop	Automation - ATR Loops	CLD	Customer-outage-minutes-avoided	116,784
3		DISTA ELM STREET02_GOODALE03	17	1	Loop	Automation - ATR Loops	BCK	Customer-outage-minutes-avoided	117,504
4		DISTA ALDRICH01_SLOAN03	4	1	Loop	Automation - ATR Loops	FLT	Customer-outage-minutes-avoided	84,816
5		DISTA HONOR01_GLEN LAKE02	433	1	Loop	Automation - ATR Loops	BEN	Customer-outage-minutes-avoided	167,424
6		DISTA BEHNKE01_QUINCY01	991	1	Loop	Automation - ATR Loops	CLD	Customer-outage-minutes-avoided	123,552
7		DISTA JACKMAN03_JACKMAN01	726	1	Loop	Automation - ATR Loops	SMN	Customer-outage-minutes-avoided	136,320
8		DISTA GOODALE03_MORGAN01	367	1	Loop	Automation - ATR Loops	BCK	Customer-outage-minutes-avoided	32,688
9		DISTA ROBERTS ST02_EAST JACKSON01	865	1	Loop	Automation - ATR Loops	JAC	Customer-outage-minutes-avoided	132,768
10		DISTA DEWEY01_HASKELITE02	11	1	Loop	Automation - ATR Loops	GRA	Customer-outage-minutes-avoided	237,312
11		DISTA RIX ROAD02_OSHTEMO01	349	1	Loop	Automation - ATR Loops	KAL	Customer-outage-minutes-avoided	49,440
12		DISTA DORR CORNERS02_BYRON CENTER04	237	1	Loop	Automation - ATR Loops	GRA	Customer-outage-minutes-avoided	140,976
13		DISTA GRAND LEDGE04_GRAND LEDGE02	456	1	Loop	Automation - ATR Loops	LAN	Customer-outage-minutes-avoided	175,584
14		DISTA HASKELITE04_FOUR MILE01	592	1	Loop	Automation - ATR Loops	GRA	Customer-outage-minutes-avoided	169,248
15		DISTA IVANREST01_BURLINGAME01	17	1	Loop	Automation - ATR Loops	GRA	Customer-outage-minutes-avoided	115,620
16		DISTA BYRON CENTER02_RIVERTOWN01	68	1	Loop	Automation - ATR Loops	GRA	Customer-outage-minutes-avoided	74,592
17		DISTA CAMELOT LAKE01_STARKS02	425	1	Loop	Automation - ATR Loops	MDL	Customer-outage-minutes-avoided	31,872
18		DISTA SHATTUCK01_LAUNDRA02	275	1	Loop	Automation - ATR Loops	SAG	Customer-outage-minutes-avoided	32,544
19		DISTA TEKONSHA02_TEKONSHA01	1,085	1	Loop	Automation - ATR Loops	CLD	Customer-outage-minutes-avoided	83,856
20		DISTA LARKIN04_LARKIN02	485	1	Loop	Automation - ATR Loops	MDL	Customer-outage-minutes-avoided	155,520
21		DISTA COWAN LK02_HARVAR LK02	367	1	Loop	Automation - ATR Loops	GRN	Customer-outage-minutes-avoided	123,648
22		DISTA KENDALL02_RAVINE02	347	1	Loop	Automation - ATR Loops	KAL	Customer-outage-minutes-avoided	104,544
23		DISTA DONTZ RD01_ONEKAMA01	571	1	Loop	Automation - ATR Loops	BEN	Customer-outage-minutes-avoided	47,424
24		DISTA EIGHT PT02_MANNSIDING01	224	1	Loop	Automation - ATR Loops	CLR	Customer-outage-minutes-avoided	29,088
25		DISTA LAKE MITCHELL02_CADILLAC03	672	1	Loop	Automation - ATR Loops	CAD	Customer-outage-minutes-avoided	54,528
26		DISTA SCIPIO02_HANOVER01	347	1	Loop	Automation - ATR Loops	JAC	Customer-outage-minutes-avoided	60,192
27		DISTA WILMOTT01_OTSEGO01	692	1	Loop	Automation - ATR Loops	HML	Customer-outage-minutes-avoided	251,904
28		DISTA GREENSPIRE01_KALARAMA01	367	1	Loop	Automation - ATR Loops	KAL	Customer-outage-minutes-avoided	90,288
29		DISTA BLINTON03_BLINTON02_UPGRADE	367	1	Loop	Automation - ATR Loops	FLT	Customer-outage-minutes-avoided	433,872
30		DISTA TECUMSEH01_HENDERSHOT02	567	1	Loop	Automation - ATR Loops	ADR	Customer-outage-minutes-avoided	147,600
31		DISTA GREENWOOD03_GREENWOOD02	694	1	Loop	Automation - ATR Loops	WBR	Customer-outage-minutes-avoided	525,936
32		DISTA COMSTOCK01_RIDGEVIEW02	429	1	Loop	Automation - ATR Loops	KAL	Customer-outage-minutes-avoided	86,400
33		DISTA LARKIN04_ASHMAN CIRCLE02	469	1	Loop	Automation - ATR Loops	MDL	Customer-outage-minutes-avoided	70,512
34		DISTA PARMA01_MAINES ROAD02	469	1	Loop	Automation - ATR Loops	JAC	Customer-outage-minutes-avoided	116,496
35		DISTA CHEYENNE01_STATE STREET01	367	1	Loop	Automation - ATR Loops	SAG	Customer-outage-minutes-avoided	64,560
36		DISTA STATE STREET03_BARNARD01	245	1	Loop	Automation - ATR Loops	SAG	Customer-outage-minutes-avoided	23,232
37		DISTA LEVEL PARK02_SPRINGFIELD04	561	1	Loop	Automation - ATR Loops	BCR	Customer-outage-minutes-avoided	127,824
38		DISTA GLENDALE02_TRAVIS02	367	1	Loop	Automation - ATR Loops	KAL	Customer-outage-minutes-avoided	92,736
39		DISTA MAYFAIR06_STANLEY02_UPGRADE	367	1	Loop	Automation - ATR Loops	FLT	Customer-outage-minutes-avoided	105,888
40		DISTA TEKONSHA01_HOMER01	840	1	Loop	Automation - ATR Loops	CLD	Customer-outage-minutes-avoided	96,000
41		DISTA MANCHESTER03_WINGATE01	592	1	Loop	Automation - ATR Loops	JAC	Customer-outage-minutes-avoided	60,480
42		DISTA MURNER01_BAGLEY03	367	1	Loop	Automation - ATR Loops	BEN	Customer-outage-minutes-avoided	110,592
43		DISTA EIGHT POINT03_SURREY01	369	1	Loop	Automation - ATR Loops	CLR	Customer-outage-minutes-avoided	91,584
44		DISTA LEVEL PARK02_BEDFORD02	581	1	Loop	Automation - ATR Loops	BCR	Customer-outage-minutes-avoided	101,376
45		DISTA FRUITPORT01_ELLIS01	883	1	Loop	Automation - ATR Loops	MUS	Customer-outage-minutes-avoided	252,528
46		DISTA MICHIGAN CTR02_EAST JACKSON02	571	1	Loop	Automation - ATR Loops	JAC	Customer-outage-minutes-avoided	156,672
47		DISTA BAGLEY01_MURNER02	245	1	Loop	Automation - ATR Loops	BEN	Customer-outage-minutes-avoided	349,248
48		DISTA CADMUS01_BEECHER02	367	1	Loop	Automation - ATR Loops	ADR	Customer-outage-minutes-avoided	130,512
49		DISTA SPRING DR02_BUTTERFIELD02	367	1	Loop	Automation - ATR Loops	FRE	Customer-outage-minutes-avoided	164,256
50		DISTA VAN BUREN02_HUDSONVILLE01 UPGRADE	490	1	Loop	Automation - ATR Loops	GRA	Customer-outage-minutes-avoided	85,200
51		DISTA BRIDGEPORT01_ALABAMA02	367	1	Loop	Automation - ATR Loops	SAG	Customer-outage-minutes-avoided	59,424
52		DISTA CONKLIN PK02_BIG PRAIRIE02	2,191	1	Loop	Automation - ATR Loops	BIG	Customer-outage-minutes-avoided	185,328
53		DISTA KOLASSA01_BURR OAK01	367	1	Loop	Automation - ATR Loops	CLD	Customer-outage-minutes-avoided	63,504
54		DISTA TINSMAN01_LONG LAKE02	367	1	Loop	Automation - ATR Loops	FLT	Customer-outage-minutes-avoided	113,952
55		DISTA BENNETT03_OKEMOS01	469	1	Loop	Automation - ATR Loops	LAN	Customer-outage-minutes-avoided	279,792
56		DISTA STATE STREET02_CHEYENNE06	695	1	Loop	Automation - ATR Loops	SAG	Customer-outage-minutes-avoided	157,632
57		**LVD Lines Reliability Subtotal (ATR Loops Total)**	**26,029**						7,560,012
58		**LVD Lines Reliability Total**	**324,261**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
Page: 17 of 35
Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT CASCO_BLUFF LCP SUB	194	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	29,154
2		RPOUT CASCO_HAWKHEAD LCP 511	162	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	321,008
3		RPOUT HOPKINS_HOPKINS LCP 0317	40	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	11,763
4		RPOUT MILLGROVE ALGNHYDR LCP 378 PT 2	150	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	152,091
5		RPOUT WILLIAMS_CRESENT	253	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	27,594
6		RPOUT WILLIAMS_ELY LCP 375	109	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	10,717
7		RPOUT CASCO_HAWKHEAD LCP 466	17	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	4,219
8		RPOUT BENTHEIM_140TH AVENUE LCP 117	86	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	54,493
9		RPOUT SAUGATUCK_SILVER LAKE LCP SUB	233	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	35,000
10		RPOUT SAUGATUCK-DOUGLAS CEMI	282	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	92,000
11		RPOUT NEW RICHMOND_NEW RICHMOND LCP 848	139	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	2,431
12		APPR RPOUT SAUGATUCK_SILVER LAKE LCP 984	110	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	17,934
13		RPOUT MONTEREY_KNELLER POLES	156	1	Project	Repetitive Outage Projects	ALLEGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	16,155
14		RLBY BELLEVUE_ASSYRIA 007 PT. 1_2	369	1	Project	Repetitive Outage Projects	EATON	Reduce Repeated Outages; Customer-outage-minutes avoided	75,906
15		RPOUT HONOR_PLATTE LCP 144 - OHL	70	1	Project	Repetitive Outage Projects	BENZIE	Reduce Repeated Outages; Customer-outage-minutes avoided	40,710
16		RPOUT HONOR_PLATTE LCP 098	112	1	Project	Repetitive Outage Projects	BENZIE	Reduce Repeated Outages; Customer-outage-minutes avoided	12,599
17		RPOUT Honor_Platte LCP 0107	179	1	Project	Repetitive Outage Projects	BENZIE	Reduce Repeated Outages; Customer-outage-minutes avoided	124,556
18		RPOUT FRANKFORT_CRYSTALLIA LCP 5032	24	1	Project	Repetitive Outage Projects	BENZIE	Reduce Repeated Outages; Customer-outage-minutes avoided	17,126
19		HZRD KOLASSA_MATTESON LCP 706 1-15	129	1	Project	Repetitive Outage Projects	BRANCH	Reduce Repeated Outages; Customer-outage-minutes avoided	2,000
20		RLBY CONVIS CONVIS 418	213	1	Project	Repetitive Outage Projects	EATON	Reduce Repeated Outages; Customer-outage-minutes avoided	9,565
21		RPOUT Ft Custer - Hill Brady LCP 254	59	1	Project	Repetitive Outage Projects	CALHOUN	Reduce Repeated Outages; Customer-outage-minutes avoided	3,750
22		RPOUT INDIAN RIVER_TOPINABEE LCP 0617	42	1	Project	Repetitive Outage Projects	CHEBOYGAN	Reduce Repeated Outages; Customer-outage-minutes avoided	75,053
23		RPOUT DEER LAKE_BALL AVENUE LCP 096	25	1	Project	Repetitive Outage Projects	CLARE	Reduce Repeated Outages; Customer-outage-minutes avoided	155,091
24		RPOUT FROST_LEOTA LCP 474	198	1	Project	Repetitive Outage Projects	ROSCOMMON	Reduce Repeated Outages; Customer-outage-minutes avoided	6,138
25		RPOUT NORTH LANSING_LABORATORY LCP 027	63	1	Project	Repetitive Outage Projects	INGHAM	Reduce Repeated Outages; Customer-outage-minutes avoided	8,231
26		RPOUT TALLMAN_WACOUSTA LCP 631	57	1	Project	Repetitive Outage Projects	CLINTON	Reduce Repeated Outages; Customer-outage-minutes avoided	72,266
27		RLBY BELLEVUE_ASSYRIA 007 PT. 3	163	1	Project	Repetitive Outage Projects	EATON	Reduce Repeated Outages; Customer-outage-minutes avoided	34,095
28		RPOUT WHITTUM_PETRIEVILLE ATR LOOP	34	1	Project	Repetitive Outage Projects	INGHAM	Reduce Repeated Outages; Customer-outage-minutes avoided	432,487
29		RPOUT COCHRAN_SNOW LCP 124	88	1	Project	Repetitive Outage Projects	EATON	Reduce Repeated Outages; Customer-outage-minutes avoided	37,584
30		RPOUT CHESTER_MORRELL LCP 0233	98	1	Project	Repetitive Outage Projects	EATON	Reduce Repeated Outages; Customer-outage-minutes avoided	15,390
31		RPOUT WAGER_PARKLAND LCP 711 ESIC OHL	102	1	Project	Repetitive Outage Projects	GENESEE	Reduce Repeated Outages; Customer-outage-minutes avoided	57,307
32		RPOUT BISHOP_RAINBOW LCP 061	143	1	Project	Repetitive Outage Projects	GENESEE	Reduce Repeated Outages; Customer-outage-minutes avoided	89,860
33		RPOUT WAGER_MARENGO LCP SUB	19	1	Project	Repetitive Outage Projects	GENESEE	Reduce Repeated Outages; Customer-outage-minutes avoided	31,172
34		RLBY LEITH/LEITH LCP 572	491	1	Project	Repetitive Outage Projects	FLINT	Reduce Repeated Outages; Customer-outage-minutes avoided	13,627
35		RPOUT COURT_KENT LCP 328	209	1	Project	Repetitive Outage Projects	GENESEE	Reduce Repeated Outages; Customer-outage-minutes avoided	23,701
36		RPOUT RED ARROW/OGEMA TLMS	218	1	Project	Repetitive Outage Projects	GENESEE	Reduce Repeated Outages; Customer-outage-minutes avoided	23,303
37		RPOUT FLUSHING_MARY STREET LCP 502	86	1	Project	Repetitive Outage Projects	GENESEE	Reduce Repeated Outages; Customer-outage-minutes avoided	15,500
38		RPOUT MONTROSE_VOLKMER LCP 322 PT 2 RAIL	29	1	Project	Repetitive Outage Projects	SAGINAW	Reduce Repeated Outages; Customer-outage-minutes avoided	17,699
39		RPOUT NEFF ROAD_DODGE ROAD LCP 325	10	1	Project	Repetitive Outage Projects	GENESEE	Reduce Repeated Outages; Customer-outage-minutes avoided	10,000
40		RPOUT WIRTZ ROAD_BOWMANVILLE	2	1	Project	Repetitive Outage Projects	GLADWIN	Reduce Repeated Outages; Customer-outage-minutes avoided	6,762
41		RPOUT OBERLIN_BENMARK LCP 639	2	1	Project	Repetitive Outage Projects	ROSCOMMON	Reduce Repeated Outages; Customer-outage-minutes avoided	24,030
42		RPOUT DIMONDALE/M99 LCP581	4	1	Project	Repetitive Outage Projects	INGHAM	Reduce Repeated Outages; Customer-outage-minutes avoided	10,108
43		RPOUT HAGADORN-WATER SUB	14	1	Project	Repetitive Outage Projects	INGHAM	Reduce Repeated Outages; Customer-outage-minutes avoided	666,766
44		RPOUT Hubbardston_Stoney Creek LCP 460	217	1	Project	Repetitive Outage Projects	IONIA	Reduce Repeated Outages; Customer-outage-minutes avoided	10,729
45		RPOUT SARANAC_KEENE LCP 669	466	1	Project	Repetitive Outage Projects	IONIA	Reduce Repeated Outages; Customer-outage-minutes avoided	246,000
46		RPOUT Belding_City LCP 513	195	1	Project	Repetitive Outage Projects	MONTCALM	Reduce Repeated Outages; Customer-outage-minutes avoided	31,000
47		RPOUT WHITTEMORE_M-65 LCP 417	19	1	Project	Repetitive Outage Projects	RENO	Reduce Repeated Outages; Customer-outage-minutes avoided	11,953
48		RPOUT WHITTEMORE_M-65 LCP 465	251	1	Project	Repetitive Outage Projects	RENO	Reduce Repeated Outages; Customer-outage-minutes avoided	41,039
49		RPOUT Brooklyn_Ford N Main St Michigan	76	1	Project	Repetitive Outage Projects	LENAWEE	Reduce Repeated Outages; Customer-outage-minutes avoided	667,868
50		RLBY Brooklyn_Ford Dearmyer Rd Fuse	10	1	Project	Repetitive Outage Projects	LENAWEE	Reduce Repeated Outages; Customer-outage-minutes avoided	539,215
51		RPOUT GULL LAKE_TURNER LCP 330	7	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	253,766
52		RPOUT YORKVILLE_BAYVIEW LCP 144	60	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	92,695
53		RPOUT COOPER_NAGEL LCP 043	110	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	72,096
54		RPOUT COMSTOCK_TUNIER LCP 891	336	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	2,494
55		RPOUT KENDALL_WESTWOOD LCP 021	21	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	874,638
56		RPOUT KILGORE_TIMBERLANE LCP 907	94	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	12,053
57		RPOUT DRAKE ROAD_COUNTRY CLUB LCP SUB	151	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	179,851
58		RPOUT PICKEREL_INDIAN LAKE LCP 803	172	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	26,902
59		RPOUT PAVILION_MERIDETH LCP SUB	66	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	891,367
60		RPOUT TEXAS_EAGLE LAKE LCP 760	165	1	Project	Repetitive Outage Projects	VAN BUREN	Reduce Repeated Outages; Customer-outage-minutes avoided	16,807
61		**Repetitive Outages Subtotal**	**7,596**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
Page: 18 of 35
Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT CUTLERVILLE_GAINES LCP 0874	18	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	100
2		RPOUT CUTLERVILLE_GAINES LCP 0172	30	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	136,894
3		RPOUT KRAFT AVENUE_FOOTHILLS LCP 910	37	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	9,001
4		RPOUT CALVIN_ROSEMONT LCP 0572	34	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	120
5		RPOUT DUTTON_GATEWAY CROSSING LCP 0711	41	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	14,750
6		RPOUT IVANREST_IVANREST LCP 0611	169	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	45,411
7		RPOUT FOREMAN_VERGENNES LCP 0741	24	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	1,080
8		RPOUT DEWEY SEATING LCP CKT 1 - 4	1258	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	1,109,395
9		RPOUT STANDALE_STANDALE LCP 356	53	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	1,125
10		RPOUT ENGLISHVILLE_PINE ISLAND LCP440 UG	141	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	35,382
11		RPOUT PLAINFIELD_BELMONT ASC RECONDUCTOR	189	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	96,387
12		RPOUT Cowan Lake_Ramsdell LCP 829	266	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	240,000
13		RPOUT HULL ST_CRANBERRY LCP-411 UG CABLE	120	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	6,880
14		RPOUT TRUFANT_MASTON LAKE LCP 206	595	1	Project	Repetitive Outage Projects	MONTCALM	Reduce Repeated Outages; Customer-outage-minutes avoided	15,295
15		RPOUT HULL STREET_LIME LAKE LCP 807	177	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	27,145
16		RPOUT HULL STREET_LIME LAKE LCP 259	157	1	Project	Repetitive Outage Projects	KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	112,022
17		RPOUT TUSTIN_LUTHER LCP 553	133	1	Project	Repetitive Outage Projects	OSCEOLA	Reduce Repeated Outages; Customer-outage-minutes avoided	33,343
18		RPOUT MAPLE CITY_CEDAR LCP 728	134	1	Project	Repetitive Outage Projects	LEELANAU	Reduce Repeated Outages; Customer-outage-minutes avoided	55,013
19		RPOUT GLEN LAKE_ARBOR LCP 8312	93	1	Project	Repetitive Outage Projects	LEELANAU	Reduce Repeated Outages; Customer-outage-minutes avoided	1,867
20		SYSP WAMPLERS_STAGECOACH	221	1	Project	Repetitive Outage Projects	WASHTENAW	Reduce Repeated Outages; Customer-outage-minutes avoided	149,040
21		SYSP WAMPLERS/FRANKLIN	80	1	Project	Repetitive Outage Projects	WASHTENAW	Reduce Repeated Outages; Customer-outage-minutes avoided	97,080
22		RPOUT DEAN ROAD_KELSEY-HAYES LCP 0037	53	1	Project	Repetitive Outage Projects	LIVINGSTON	Reduce Repeated Outages; Customer-outage-minutes avoided	10,000
23		RPOUT DEAN ROAD_PARSHALLVILLE LCP 16 SH1_2	304	1	Project	Repetitive Outage Projects	LIVINGSTON	Reduce Repeated Outages; Customer-outage-minutes avoided	82,412
24		RPOUT ORIOLE_HAMLIN LCP 5061	8	1	Project	Repetitive Outage Projects	MASON	Reduce Repeated Outages; Customer-outage-minutes avoided	92,781
25		RPOUT PRICE ROAD_MERIDIAN LCP 0513	19	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	2,873,044
26		RPOUT LEVELY_STURGEON LCP 011	39	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	29,473
27		RPOUT CRYSTAL_MT HOPE ROAD LCP 438	170	1	Project	Repetitive Outage Projects	MONTCALM	Reduce Repeated Outages; Customer-outage-minutes avoided	105,091
28		RPOUT PECK ROAD_WISE ROAD LCP 484	346	1	Project	Repetitive Outage Projects	MONTCALM	Reduce Repeated Outages; Customer-outage-minutes avoided	97,903
29		RPOUT EVANSTON_EVANSTON LCP 810	246	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	54,220
30		RPOUT NUNICA_WILSON LCP 508	160	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	24,471
31		RPOUT FRUITPORT_JUDSON ROAD LCP 0642	151	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	29,165
32		RPOUT APPLE_CHATTERSON ROAD LCP 613	193	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	21,978
33		RPOUT WESTERN AVENUE_BARCLAY LCP 376	27	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	28,770
34		RPOUT CLUB_ADVENTURE LCP 891	51	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	149,572
35		RPOUT BENSTON_DURHAM LCP 481	87	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	10,692
36		RPOUT - EAST GRANT - MUD FLAT - LCP 728	271	1	Project	Repetitive Outage Projects	NEWAYGO	Reduce Repeated Outages; Customer-outage-minutes avoided	31,528
37		RPOUT BUTTERFIELD_M-82 LCP 221	250	1	Project	Repetitive Outage Projects	NEWAYGO	Reduce Repeated Outages; Customer-outage-minutes avoided	176,874
38		RPOUT BIG PRAIRIE/OXBOW LCP 908	428	1	Project	Repetitive Outage Projects	NEWAYGO	Reduce Repeated Outages; Customer-outage-minutes avoided	30,392
39		RPOUT HESPERIA_RURAL LCP 035	40	1	Project	Repetitive Outage Projects	NEWAYGO	Reduce Repeated Outages; Customer-outage-minutes avoided	18,720
40		RPOUT HESPERIA_RURAL LCP 481	161	1	Project	Repetitive Outage Projects	NEWAYGO	Reduce Repeated Outages; Customer-outage-minutes avoided	45,277
41		RPOUT FISH LAKE_SEVEN LAKES LCP 0136	226	1	Project	Repetitive Outage Projects	OAKLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	67,397
42		RPOUT ALGER_SKIDWAY LCP 0062	161	1	Project	Repetitive Outage Projects	OGEMAW	Reduce Repeated Outages; Customer-outage-minutes avoided	7,229
43		RPOUT ALGER_SKIDWAY LCP 663	549	1	Project	Repetitive Outage Projects	OGEMAW	Reduce Repeated Outages; Customer-outage-minutes avoided	236,023
44		RPOUT ALGER_SKIDWAY LCP 449	123	1	Project	Repetitive Outage Projects	OGEMAW	Reduce Repeated Outages; Customer-outage-minutes avoided	16,757
45		RPOUT PRESCOTT_LOGAN LCP 527	226	1	Project	Repetitive Outage Projects	OGEMAW	Reduce Repeated Outages; Customer-outage-minutes avoided	4,915
46		RPOUT RANGER LAKE/LUPTON LCP 0071	77	1	Project	Repetitive Outage Projects	OGEMAW	Reduce Repeated Outages; Customer-outage-minutes avoided	77,825
47		RPOUT TUSTIN_LUTHER LCP 568	122	1	Project	Repetitive Outage Projects	OSCEOLA	Reduce Repeated Outages; Customer-outage-minutes avoided	17,780
48		RPOUT MURNER_VAN TYLE CALKINS ESIC UGL	241	1	Project	Repetitive Outage Projects	OTSEGO	Reduce Repeated Outages; Customer-outage-minutes avoided	15,550
49		RPOUT-MURNER_VAN TYLE LCP 930	421	1	Project	Repetitive Outage Projects	OTSEGO	Reduce Repeated Outages; Customer-outage-minutes avoided	21,286
50		RPOUT MURNER_ASPEN LCP 0915	70	1	Project	Repetitive Outage Projects	OTSEGO	Reduce Repeated Outages; Customer-outage-minutes avoided	201,683
51		RPOUT MURNER_ASPEN LCP SUB	128	1	Project	Repetitive Outage Projects	OTSEGO	Reduce Repeated Outages; Customer-outage-minutes avoided	494,266
52		RPOUT LOGISTIC FELCH LCP 837	397	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	339,008
53		RPOUT PIGEON LAKE_PIGEON LCP 871	298	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	122,445
54		RPOUT PIGEON LAKE_PIGEON LCP 454 PART 1_2	150	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	6,107
55		RPOUT ARTHUR_BERLIN LCP 0967	36	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	40,548
56		RPOUT BILMAR PEIRCE LCP 725	163	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	12,770
57		RPOUT JOHNSON_CEDAR LCP 573	128	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	90,691
58		RPOUT JOHNSON_LINCOLN LCP 0224-OHL	204	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	18,000
59		RPOUT NUNICA_WILSON LCP 568	39	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	31,873
60	**Repetitive Outages Subtotal**		**10,735**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT SAVIDGE_BOOM ROAD LCP 729	212	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	3,621
2		RPOUT JOHNSON_CEDAR LCP 0566	292	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	170,000
3		RPOUT FRUITPORT_JUDSON ROAD LCP 0763	6	1	Project	Repetitive Outage Projects	OTTAWA	Reduce Repeated Outages; Customer-outage-minutes avoided	53,476
4		RPOUT BELL ROAD/ALBEE LCP 702	34	1	Project	Repetitive Outage Projects	SAGINAW	Reduce Repeated Outages; Customer-outage-minutes avoided	27,584
5		RPOUT BUSCH ROAD/CURTIS LCP 0134	11	1	Project	Repetitive Outage Projects	SAGINAW	Reduce Repeated Outages; Customer-outage-minutes avoided	3,262
6		RPOUT Teft Rd Graham LCP349	6	1	Project	Repetitive Outage Projects	SAGINAW	Reduce Repeated Outages; Customer-outage-minutes avoided	947
7		RPOUT Teft Rd Lakefield LCP331	176	1	Project	Repetitive Outage Projects	SAGINAW	Reduce Repeated Outages; Customer-outage-minutes avoided	13,565
8		RPOUT PORTSMOUTH/BLUMFIELD LCP 575	36	1	Project	Repetitive Outage Projects	TUSCOLA	Reduce Repeated Outages; Customer-outage-minutes avoided	2,015
9		RPOUT PORTSMOUTH/INDIANTOWN LCP 054	43	1	Project	Repetitive Outage Projects	TUSCOLA	Reduce Repeated Outages; Customer-outage-minutes avoided	25,580
10		RPOUT Colon_Colon LCP 947	149	1	Project	Repetitive Outage Projects	ST JOSEPH	Reduce Repeated Outages; Customer-outage-minutes avoided	76,392
11		RPOUT BURR OAK_INDUSTRIAL LCP 521	58	1	Project	Repetitive Outage Projects	ST JOSEPH	Reduce Repeated Outages; Customer-outage-minutes avoided	14,197
12		RPOUT PEACOCK_STOLL ROAD LCP 492	133	1	Project	Repetitive Outage Projects	SHIAWASSEE	Reduce Repeated Outages; Customer-outage-minutes avoided	21,729
13		FUSE NEWBURG_BANCROFT LCP 300 9	25	1	Project	Repetitive Outage Projects	SHIAWASSEE	Reduce Repeated Outages; Customer-outage-minutes avoided	18,097
14		RPOUT Durand City LCP 551	405	1	Project	Repetitive Outage Projects	SHIAWASSEE	Reduce Repeated Outages; Customer-outage-minutes avoided	230,062
15		RPOUT Durand City Fusing	75	1	Project	Repetitive Outage Projects	SHIAWASSEE	Reduce Repeated Outages; Customer-outage-minutes avoided	230,062
16		RPOUT NEW LOTHROP_BYRON ROAD LCP 274	99	1	Project	Repetitive Outage Projects	SHIAWASSEE	Reduce Repeated Outages; Customer-outage-minutes avoided	7,811
17		RPOUT NEW LOTHROP_BYRON ROAD LCP 273	22	1	Project	Repetitive Outage Projects	SHIAWASSEE	Reduce Repeated Outages; Customer-outage-minutes avoided	124,487
18		RPOUT ALAMO_PINE GROVE LCP 491	176	1	Project	Repetitive Outage Projects	VAN BUREN	Reduce Repeated Outages; Customer-outage-minutes avoided	429,862
19		RPOUT BREEDSVILLE_GRAND JUNCTION LCP 823	220	1	Project	Repetitive Outage Projects	VAN BUREN	Reduce Repeated Outages; Customer-outage-minutes avoided	27,071
20		RPOUT BREEDSVILLE_BREEDSVILLE LCP 341	228	1	Project	Repetitive Outage Projects	VAN BUREN	Reduce Repeated Outages; Customer-outage-minutes avoided	40,068
21		RPOUT ALAMO_FISH HATCHERY LCP 736	120	1	Project	Repetitive Outage Projects	VAN BUREN	Reduce Repeated Outages; Customer-outage-minutes avoided	45,425
22		RPOUT SYLVAN CITY LCP 797	110	1	Project	Repetitive Outage Projects	WASHTENAW	Reduce Repeated Outages; Customer-outage-minutes avoided	1,410
23		RPOUT JUDD ROAD_CARMANWOOD LCP 545	30	1	Project	Repetitive Outage Projects	MUNDY	Reduce Repeated Outages; Customer-outage-minutes avoided	30,000
24		RPOUT BALDWIN_IDLEWILD LCP 0444	14	1	Project	Repetitive Outage Projects	BALDWIN	Reduce Repeated Outages; Customer-outage-minutes avoided	7,748
25		RPOUT BALZER_SANDERS LCP 0254	42	1	Project	Repetitive Outage Projects	AURELIUS	Reduce Repeated Outages; Customer-outage-minutes avoided	63788
26		RPOUT AUGUSTA_HOSPITAL LCP 534	234	1	Project	Repetitive Outage Projects	AUGUSTA	Reduce Repeated Outages; Customer-outage-minutes avoided	32124
27		RPOUT BALDWIN_IDLEWILD LCP 421	341	1	Project	Repetitive Outage Projects	IDLEWILD	Reduce Repeated Outages; Customer-outage-minutes avoided	127838
28		RPOUT PIGEON LAKE_PIGEON LCP 267	250	1	Project	Repetitive Outage Projects	PORT SHELDON	Reduce Repeated Outages; Customer-outage-minutes avoided	107991
29		RPOUT PIGEON LAKE_PIGEON LCP 802	250	1	Project	Repetitive Outage Projects	PORT SHELDON	Reduce Repeated Outages; Customer-outage-minutes avoided	95963
30		RPOUT PIGEON LAKE_PIGEON LCP 210	165	1	Project	Repetitive Outage Projects	PORT SHELDON	Reduce Repeated Outages; Customer-outage-minutes avoided	5634
31		RPOUT CLARE_FARWELL LCP 373	17	1	Project	Repetitive Outage Projects	CLARE	Reduce Repeated Outages; Customer-outage-minutes avoided	82829
32		RPOUT MARNE_WRIGHT LCP 047	22	1	Project	Repetitive Outage Projects	WRIGHT	Reduce Repeated Outages; Customer-outage-minutes avoided	8992
33		RPOUT FILLMORE_NORTH BLENDON LCP 0396	419	1	Project	Repetitive Outage Projects	ALLENDALE	Reduce Repeated Outages; Customer-outage-minutes avoided	57673
34		RPOUT WHITEHALL_HANSON LCP 758	39	1	Project	Repetitive Outage Projects	MONTAGUE	Reduce Repeated Outages; Customer-outage-minutes avoided	1500
35		RPOUT INDIAN RIVER_TOPINABEE LCP 659	448	1	Project	Repetitive Outage Projects	MULLETT	Reduce Repeated Outages; Customer-outage-minutes avoided	285214
36		RPOUT HOGSBACK_CEDAR LCP 733	87	1	Project	Repetitive Outage Projects	DELHI	Reduce Repeated Outages; Customer-outage-minutes avoided	14441
37		RPOUT VAN BUREN_VAN BUREN LCP 0889	384	1	Project	Repetitive Outage Projects	GEORGETOWN	Reduce Repeated Outages; Customer-outage-minutes avoided	27686
38		RPOUT GREENWOOD_INDIAN LAKE LCP 329	33	1	Project	Repetitive Outage Projects	CLEMENT	Reduce Repeated Outages; Customer-outage-minutes avoided	5600
39		RPOUT PIGEON LAKE_PIGEON LCP 803	335	1	Project	Repetitive Outage Projects	PORT SHELDON	Reduce Repeated Outages; Customer-outage-minutes avoided	188484
40		RPOUT NORTON_PONTALUNA ROAD LCP 359	2	1	Project	Repetitive Outage Projects	ROOSEVELT PARK	Reduce Repeated Outages; Customer-outage-minutes avoided	156925
41		RPOUT VANDERBILT_WOLVERINE LCP 346	37	1	Project	Repetitive Outage Projects	WILMOT	Reduce Repeated Outages; Customer-outage-minutes avoided	361971
42		RPOUT BELKNAP_TODD FARM LCP 921	70	1	Project	Repetitive Outage Projects	GANGES	Reduce Repeated Outages; Customer-outage-minutes avoided	15325
43		RPOUT 2750 S STATE RD 137102	10	1	Project	Repetitive Outage Projects	BERLIN	Reduce Repeated Outages; Customer-outage-minutes avoided	71310
44		RPOUT BYRON CENTER_BYRON CENTER LCP 0428	188	1	Project	Repetitive Outage Projects	BYRON	Reduce Repeated Outages; Customer-outage-minutes avoided	15574
45		RPOUT HANOVER_HORTON LCP 507	289	1	Project	Repetitive Outage Projects	HANOVER	Reduce Repeated Outages; Customer-outage-minutes avoided	159256
46		RPOUT HANOVER_HORTON	218	1	Project	Repetitive Outage Projects	HANOVER	Reduce Repeated Outages; Customer-outage-minutes avoided	132620
47		RPOUT MCNALLY_LEXALITE LCP 099	178	1	Project	Repetitive Outage Projects	BAY SHORE	Reduce Repeated Outages; Customer-outage-minutes avoided	107763
48		RPOUT RAVENNA_MOORLAND LCP 177	165	1	Project	Repetitive Outage Projects	MOORLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	32071
49		RPOUT GODFREY_FLAT RIVER LCP 0535	261	1	Project	Repetitive Outage Projects	VERGENNES	Reduce Repeated Outages; Customer-outage-minutes avoided	47218
50		RPOUT SARANAC_CENTERLINE LCP 509	273	1	Project	Repetitive Outage Projects	KEENE	Reduce Repeated Outages; Customer-outage-minutes avoided	47945
51		RPOUT MARKER LAKE_JACKSON ROAD LCP 364	260	1	Project	Repetitive Outage Projects	BOSTON	Reduce Repeated Outages; Customer-outage-minutes avoided	33507
52		RPOUT BEHNKE_ANGOLA ROAD LCP 440	195	1	Project	Repetitive Outage Projects	COLDWATER	Reduce Repeated Outages; Customer-outage-minutes avoided	45776
53		RPOUT GRANT_MASON DRIVE LCP 238	23	1	Project	Repetitive Outage Projects	ASHLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	38345
54		RPOUT ALAMO_OWEN LCP 0240	9	1	Project	Repetitive Outage Projects	ALAMO	Reduce Repeated Outages; Customer-outage-minutes avoided	1212
55		RPOUT ALAMO_OWEN LCP 0364	2	1	Project	Repetitive Outage Projects	ALAMO	Reduce Repeated Outages; Customer-outage-minutes avoided	4741
56		RPOUT ALAMO_OWEN LCP 239	2	1	Project	Repetitive Outage Projects	ALAMO	Reduce Repeated Outages; Customer-outage-minutes avoided	5565
57		RPOUT NORTH KENT_MALL LCP 165 UG CABLE	189	1	Project	Repetitive Outage Projects	BELMONT	Reduce Repeated Outages; Customer-outage-minutes avoided	64992
58		RPOUT CRAHEN_LOMOND LCP 345	24	1	Project	Repetitive Outage Projects	EAST GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	246183
59		RPOUT GRAND VALLEY/TALLMADGE LCP 149	30	1	Project	Repetitive Outage Projects	TALLMADGE	Reduce Repeated Outages; Customer-outage-minutes avoided	18445
60		48TH AVE - BIRD ISSUES	2	1	Project	Repetitive Outage Projects	GEORGETOWN	Reduce Repeated Outages; Customer-outage-minutes avoided	813
61		**Repetitive Outages Subtotal**	**8,170**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT GRASS LAKE_GRASS LAKE LCP 624	44	1	Project	Repetitive Outage Projects	GRASS LAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	12012
2		RPOUT MARTIN_SHELBYVILLE LCP 0232	1	1	Project	Repetitive Outage Projects	WATSON	Reduce Repeated Outages; Customer-outage-minutes avoided	8000
3		RPOUT BAYBERRY_PLEASANT HILL LCP SUB	266	1	Project	Repetitive Outage Projects	BYRON	Reduce Repeated Outages; Customer-outage-minutes avoided	41431
4		RPOUT ELEVENTH STREET_BASELINE LCP 871	1	1	Project	Repetitive Outage Projects	ALAMO	Reduce Repeated Outages; Customer-outage-minutes avoided	5012
5		RPOUT TWIN LAKE_TWIN LAKE LCP 777	322	1	Project	Repetitive Outage Projects	DALTON	Reduce Repeated Outages; Customer-outage-minutes avoided	193987
6		RPOUT DELTON_DELTON LCP 0126	7	1	Project	Repetitive Outage Projects	DOSTER	Reduce Repeated Outages; Customer-outage-minutes avoided	32000
7		RPOUT FILLMORE_NORTH BLENDON LCP 0285	81	1	Project	Repetitive Outage Projects	BLENDON	Reduce Repeated Outages; Customer-outage-minutes avoided	87371
8		RPOUT PELLSTON_BURT LAKE LCP 175	247	1	Project	Repetitive Outage Projects	BURT	Reduce Repeated Outages; Customer-outage-minutes avoided	17344
9		RPOUT NORTON_HILE ROAD SUB EXIT	44	1	Project	Repetitive Outage Projects	FRUITPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	613000
10		RPOUT BENSTON_DURHAM LCP 481 - OH	58	1	Project	Repetitive Outage Projects	MONTAGUE	Reduce Repeated Outages; Customer-outage-minutes avoided	NULL
11		RPOUT INDIAN RIVER_TOPINABEE LCP SUB	17	1	Project	Repetitive Outage Projects	KOEHLER	Reduce Repeated Outages; Customer-outage-minutes avoided	NULL
12		RPOUT NORTON_HILE ROAD LCP 444	36	1	Project	Repetitive Outage Projects	ROOSEVELT PARK	Reduce Repeated Outages; Customer-outage-minutes avoided	8536
13		RPOUT HILL ROAD_REGENCY LCP 113	11	1	Project	Repetitive Outage Projects	MUNDY	Reduce Repeated Outages; Customer-outage-minutes avoided	3000
14		RPOUT TUSTIN_LUTHER LCP 807	14	1	Project	Repetitive Outage Projects	LUTHER	Reduce Repeated Outages; Customer-outage-minutes avoided	10820
15		RPOUT VANDERBILT_WOLVERINE LCP 471	95	1	Project	Repetitive Outage Projects	AFTON	Reduce Repeated Outages; Customer-outage-minutes avoided	64500
16		RPOUT MCCRACKEN_LEON LCP 172	12	1	Project	Repetitive Outage Projects	ROOSEVELT PARK	Reduce Repeated Outages; Customer-outage-minutes avoided	54248
17		RPOUT DEAN ROAD_PARSHALLVILLE LCP 16 SH1	200	1	Project	Repetitive Outage Projects	DEERFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	82412
18		RPOUT CENTRAL LAKE_ELLSWORTH LCP 742	433	1	Project	Repetitive Outage Projects	CENTRAL LAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	102034
19		RPOUT FRUITPORT_JUDSON ROAD LCP 437	6	1	Project	Repetitive Outage Projects	CROCKERY	Reduce Repeated Outages; Customer-outage-minutes avoided	50054
20		RPOUT NORTON_PONTALUNA ROAD LCP 335	138	1	Project	Repetitive Outage Projects	FRUITPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	115500
21		RPOUT ARTHUR_ARTHUR LCP 304	4	1	Project	Repetitive Outage Projects	COOPERSVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	4000
22		RPOUT NEELEY_HOOPER LCP 961 ESIC OHL	164	1	Project	Repetitive Outage Projects	ORANGEVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	85352
23		RPOUT ALGER_SKIDWAY LCP 663 and 163 PTB	189	1	Project	Repetitive Outage Projects	MILLS	Reduce Repeated Outages; Customer-outage-minutes avoided	33659
24		RPOUT HESPERIA_RURAL LCP 481 - OHL	144	1	Project	Repetitive Outage Projects	DENVER	Reduce Repeated Outages; Customer-outage-minutes avoided	20678
25		SYSP BILLWOOD_BILLWOOD LCP SUB	22	1	Project	Repetitive Outage Projects	DIMONDALE	Reduce Repeated Outages; Customer-outage-minutes avoided	17000
26		RPOUT NESTROM_SOUTH SHORE LCP 629	323	1	Project	Repetitive Outage Projects	FRUITLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	19875
27		RPOUT DONTZ ROAD_KOTT ROAD LCP 515	42	1	Project	Repetitive Outage Projects	FILER	Reduce Repeated Outages; Customer-outage-minutes avoided	33735
28		RPOUT BEECH-NUT_HOLAGAN LCP 266	259	1	Project	Repetitive Outage Projects	FILLMORE	Reduce Repeated Outages; Customer-outage-minutes avoided	71711
29		RPOUT BLACK RIVER_FILLMORE LCP 146	68	1	Project	Repetitive Outage Projects	ZEELAND	Reduce Repeated Outages; Customer-outage-minutes avoided	43534
30		RPOUT COMSTOCK_TUNIER LCP 891 ESIC OHL	46	1	Project	Repetitive Outage Projects	COMSTOCK	Reduce Repeated Outages; Customer-outage-minutes avoided	2494
31		RPOUT ALGER_SKIDWAY LCP 606	61	1	Project	Repetitive Outage Projects	MILLS	Reduce Repeated Outages; Customer-outage-minutes avoided	1822
32		RPOUT WIRTZ ROAD_BOWMANVILLE LCP 461	141	1	Project	Repetitive Outage Projects	BOURRET	Reduce Repeated Outages; Customer-outage-minutes avoided	21224
33		RPOUT WHITTEMORE_M-65 LCP 919	140	1	Project	Repetitive Outage Projects	RENO	Reduce Repeated Outages; Customer-outage-minutes avoided	57890
34		RLBY CLEAR LAKE_WATERLOO CKT	10	1	Project	Repetitive Outage Projects	GRASS LAKE	Reduce Repeated Outages; Customer-outage-minutes avoided	641776
35		RPOUT THORNTON_WEST RIVER RD LCP 352	53	1	Project	Repetitive Outage Projects	JEROME	Reduce Repeated Outages; Customer-outage-minutes avoided	102619
36		RLBY NEFF ROAD_LEWIS ROAD LCP sub	64	1	Project	Repetitive Outage Projects	CLIO	Reduce Repeated Outages; Customer-outage-minutes avoided	922536
37		RPOUT SPRING DRIVE_BISHOP LAKE CKT	15	1	Project	Repetitive Outage Projects	GARFIELD	Reduce Repeated Outages; Customer-outage-minutes avoided	331838
38		RPOUT STONEGATE_BREVIS LCP 541	201	1	Project	Repetitive Outage Projects	GRANDVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	2260
39		RPOUT HASKELITE_FISHER BODY LCP 870	465	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	7375
40		RPOUT BROADWAY_BLACK CREEK LCP 666	293	1	Project	Repetitive Outage Projects	FRUITPORT	Reduce Repeated Outages; Customer-outage-minutes avoided	100566
41		RPOUT STANDALE_CHESTERFIELD LCP 312	347	1	Project	Repetitive Outage Projects	TALLMADGE	Reduce Repeated Outages; Customer-outage-minutes avoided	22197
42		RPOUT ALGER_SKIDWAY LCP 819	127	1	Project	Repetitive Outage Projects	MILLS	Reduce Repeated Outages; Customer-outage-minutes avoided	28425
43		RPOUT NESTROM_SCENIC DRIVE LCP 191	2	1	Project	Repetitive Outage Projects	FRUITLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	3600
44		RPOUT CHAPIN_MARION LCP 933	14	1	Project	Repetitive Outage Projects	MARION	Reduce Repeated Outages; Customer-outage-minutes avoided	2801
45		SYSP SWARTZ CREEK_MAPLE ROAD LCP 216	10	1	Project	Repetitive Outage Projects	CLAYTON	Reduce Repeated Outages; Customer-outage-minutes avoided	32480
46		RPOUT STANDALE_PARKSIDE LCP 156	2	1	Project	Repetitive Outage Projects	TALLMADGE	Reduce Repeated Outages; Customer-outage-minutes avoided	55140
47		RPOUT RIVERTOWN_56TH LCP 941	7	1	Project	Repetitive Outage Projects	TALLMADGE	Reduce Repeated Outages; Customer-outage-minutes avoided	1400
48		RPOUT MULLINS_ROYAL VISTA LCP 446	9	1	Project	Repetitive Outage Projects	ALPINE	Reduce Repeated Outages; Customer-outage-minutes avoided	74897
49		RPOUT WEALTHY STREET_WATSON LCP 221	2	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	7212
50		RPOUT MILL GROVE_DUMONT LCP 667	163	1	Project	Repetitive Outage Projects	VALLEY	Reduce Repeated Outages; Customer-outage-minutes avoided	74479
51		RPOUT SWAN CREEK_COPPER LCP 136 and 123	166	1	Project	Repetitive Outage Projects	CHESHIRE	Reduce Repeated Outages; Customer-outage-minutes avoided	54234
52		RPOUT SWAN CREEK_COPPER LCP 810	105	1	Project	Repetitive Outage Projects	CHESHIRE	Reduce Repeated Outages; Customer-outage-minutes avoided	46951
53		RPOUT SWAN CREEK_MINING LCP 105	101	1	Project	Repetitive Outage Projects	VALLEY	Reduce Repeated Outages; Customer-outage-minutes avoided	11776
54		RPOUT SWAN CREEK_MINING LCP 180	484	1	Project	Repetitive Outage Projects	CHESHIRE	Reduce Repeated Outages; Customer-outage-minutes avoided	158000
55		RPOUT SWAN CREEK_MINING LCP 141	200	1	Project	Repetitive Outage Projects	CHESHIRE	Reduce Repeated Outages; Customer-outage-minutes avoided	46897
56		RPOUT SWAN CREEK_MINING LCP 070	195	1	Project	Repetitive Outage Projects	CHESHIRE	Reduce Repeated Outages; Customer-outage-minutes avoided	265196
57		RPOUT BIL-MAR_PIERCE LCP 217	48	1	Project	Repetitive Outage Projects	OLIVE	Reduce Repeated Outages; Customer-outage-minutes avoided	280918
58		**Repetitive Outages Subtotal**	**6,715**						
59		**Repetitive Outages Total**	**33,215**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	DEVATR25 ST Charles02_Teft01 LCP217	69	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
2		FA W 24 RD MESICK - ESIC	23	1	Project	Imminent Rehabilitation	WEXFORD	Improve Secondary Voltage ; Customers	5
3		FA - E OAK ST - FRE - SVLT	105	1	Project	Imminent Rehabilitation	NEWAYGO	Improve Secondary Voltage ; Customers	5
4		FA - W 24TH ST - FRE - MRC1	5	1	Project	Imminent Rehabilitation	NEWAYGO	Attachment Clearance Violation ; Customers	1
5		FA -W BRIDGE ST, PLAINWELL - DSRV	95	1	Project	Imminent Rehabilitation	ALLEGAN	Deteriorated Service Replacement ; Customers	1
6		FA-HOCKADAY RD GLD-SVLT	10	1	Project	Imminent Rehabilitation	GLADWIN	Improve Secondary Voltage ; Customers	5
7		FA-OBERLIN PRATT LAKE LCP 010	30	1	Project	Imminent Rehabilitation	GLADWIN	Replace Deteriorated Pole ; Customers	242
8		FA OBERLIN PRATT LAKE LCP 659	15	1	Project	Imminent Rehabilitation	GLADWIN	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
9		FA CASS RD CASS RD LCP 561 FAIL UG	120	1	Project	Imminent Rehabilitation	GRAND TRAVERS	Replace Deteriorated Underground Primary ; Customers	43
10		FA CASS RD CASS RD LCP 561- ESIC OHL	5	1	Project	Imminent Rehabilitation	GRAND TRAVERS	Replace Deteriorated Underground Primary ; Customers	43
11		FA - SPRINGVIEW DR, BATTLE CREEK	41	1	Project	Imminent Rehabilitation	CALHOUN	Replace Deteriorated Underground Primary ; Customers	43
12		FA Cascade Thorncrest I-96 HWY crossing	29	1	Project	Imminent Rehabilitation	KENT	Retire and Remove Unused Assets; Customers	58
13		Old 28th St SE Car Wash UGL	41	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
14		FA- BELSAY RD, GRAND BLANC - POL2	29	1	Project	Imminent Rehabilitation	GENESEE	Replace Deteriorated Pole ; Customers	2
15		FA-WYANDOTTE NE LOW VOLTAGE	30	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	242
16		FA - CHESANING RD, CHESANING; POL	17	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Pole or Pole Top Equipment ; Customers	242
17		FA REHAB BRETON-PLYMOUTH LCP 411	88	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Underground Primary ; Customers	5
18		FA BRETON-PLYMOUTH LCP 463 UG	44	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Underground Primary ; Customers	2
19		FA - FRISBIE BLVD	125	1	Project	Imminent Rehabilitation	CALHOUN	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	43
20		FA-N MAIN ST LGLK - SYS UPGRADE	48	1	Project	Imminent Rehabilitation	IOSCO	Improve Secondary Voltage ; Customers	5
21		FA - BIG OLE DR, SOUTH BRANCH -OHC2	7	1	Project	Imminent Rehabilitation	IOSCO	Correct Conductor Clearance Violation ; Customers	0
22		FA-OLD ALLEGAN RD, FENNVILLE -FRRE	39	1	Project	Imminent Rehabilitation	ALLEGAN	Retire and Remove Unused Assets; Customers	43
23		FA - N GREENWOOD RD TSC ESIC OHL	2	1	Project	Imminent Rehabilitation	IOSCO	Improve Secondary Voltage ; Customers	12
24		FA AULERICH RD ETAW ESIC UGL	44	1	Project	Imminent Rehabilitation	IOSCO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
25		FA - TIMBERLYNN TRL, SANFORD; BOVE	5	1	Project	Imminent Rehabilitation	MIDLAND	Relocate Electric With Structure Encroachment ; Customers	242
26		FA MILLERS POINT_MEADOW VIEW LCP 673T	8	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	24
27		FA EASTON RD	25	1	Project	Imminent Rehabilitation	JACKSON	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	58
28		FA EASTON RD - 8610 SERVICE	5	1	Project	Imminent Rehabilitation	JACKSON	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	2
29		FA VANDERBILT_WOLVERINE LCP 346	7	1	Project	Imminent Rehabilitation	CHEBOYGAN	Improve Secondary Voltage ; Customers	5
30		FA Anthony Dr., Centreville BAD UG	36	1	Project	Imminent Rehabilitation	ST JOSEPH	Replace Deteriorated Underground Primary ; Customers	5
31		TALLMAN_WACOUSTA LCP 493 ECNO RSU	3	1	Project	Imminent Rehabilitation	CLINTON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
32		FA-Sprinkle Rd-POL2	75	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole ; Customers	1
33		FA FOREMAN CKT 1_VERGENNES ST SE	12	1	Project	Imminent Rehabilitation	KENT	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	520
34		FA-TIMPSON AVE, LOWELL-UPGRADE SVC	5	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	12
35		FA - N BEYER RD, SGN; OHC2	5	1	Project	Imminent Rehabilitation	SAGINAW	Correct Conductor Clearance Violation ; Customers	12
36		FA - 121ST AVE - FLRE	105	1	Project	Imminent Rehabilitation	ALLEGAN	Replace Deteriorated Pole ; Customers	242
37		FA MAIN ST JENISON	8	1	Project	Imminent Rehabilitation	OTTAWA	Correct Conductor Clearance Violation ; Customers	5
38		FA- MAPLE BLUFF, PRUDENVILLE-SVLT	10	1	Project	Imminent Rehabilitation	ROSCOMMON	Improve Secondary Voltage ; Customers	43
39		FA - E LUDINGTON, CLARE- OHL - PFCP	60	1	Project	Imminent Rehabilitation	CLARE	Replace Deteriorated Underground Primary ; Customers	24
40		FA George RD_Cap Bank	14	1	Project	Imminent Rehabilitation	ST JOSEPH	Improve Primary Voltage ; Customers	5
41		FA SUGARLOAF CLEAR LAKE WATERLOO	5	1	Project	Imminent Rehabilitation	WASHTENAW	Replace Deteriorated Pole ; Customers	2
42		FA - IRISH RD, GRAND BLANC - FLRE	22	1	Project	Imminent Rehabilitation	GENESEE	Replace Deteriorated Pole or Pole Top Equipment ; Customers	20
43		ALLENDALE RBLD SPAN - ESIC OHL	9	1	Project	Imminent Rehabilitation	OTTAWA	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
44		FA-WELCH LAKE RD GRASS LAKE-OHC2	5	1	Project	Imminent Rehabilitation	JACKSON	Correct Conductor Clearance Violation ; Customers	5
45		FA-Alber - ALber LCP 802-ESIC UGL	29	1	Project	Imminent Rehabilitation	CALHOUN	Replace Deteriorated Underground Primary ; Customers	24
46		FA-Alber - ALber LCP 802-ESIC OHL	5	1	Project	Imminent Rehabilitation	CALHOUN	Replace Deteriorated Underground Primary ; Customers	2
47		RAY ST, SAG, ESIC OHS	5	1	Project	Imminent Rehabilitation	SAGINAW	Deteriorated Service Replacement ; Customers	24
48		FA - ADAMS RD, STERLING - PVLT	8	1	Project	Imminent Rehabilitation	ARENAC	Improve Primary Voltage ; Customers	5
49		FA-PULLMAN-CHICORA 110THAVE&52NDST FRRE	7	1	Project	Imminent Rehabilitation	ALLEGAN	Retire and Remove Unused Assets; Customers	43
50		FA-PULLMAN-CHICORA 50TH ST OHC1	8	1	Project	Imminent Rehabilitation	ALLEGAN	Correct Conductor Clearance Violation ; Customers	24
51		FA - ALVIN DR, SIX LAKES - SVLT	11	1	Project	Imminent Rehabilitation	MONTCALM	Improve Secondary Voltage ; Customers	24
52		Critical Fl S Holmes	48	1	Project	Imminent Rehabilitation	SHIAWASSEE	Replace Deteriorated Pole or Pole Top Equipment ; Customers	43
53		FA - CRANE AVE, KZO - ESIC OHL	40	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	242
54		FA - CRANE AVE, KZO - ESIC UGL	32	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	24
55		FA - Woodbine st JAX	5	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	5
56		FA - 7 MILE RD NE, LOWELL - OHC2	20	1	Project	Imminent Rehabilitation	KENT	Correct Conductor Clearance Violation ; Customers	43
57		FA - Vreg Needed at Riverview & D Ave	4	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	520
58		FA-BROOMFIELD RD MT PLEASANT-SVLT	9	1	Project	Imminent Rehabilitation	ISABELLA	Improve Secondary Voltage ; Customers	5
59		FA-Beaverton Ross St LCP 407 REG	13	1	Project	Imminent Rehabilitation	GLADWIN	Improve Primary Voltage ; Customers	5
60		FA-Beaverton Tobacco LCP 452	9	1	Project	Imminent Rehabilitation	GLADWIN	Replace Deteriorated Regulator ; Customers	520
61		**Imminent Rehabilitation Subtotal**	**1,737**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	Critical FL N State Rd Ionia SVLT	13	1	Project	Imminent Rehabilitation	IONIA	Replace Deteriorated Pole or Pole Top Equipment ; Customers	242
2		Crit FL N State Rd Ionia RSU	10	1	Project	Imminent Rehabilitation	IONIA	Replace Deteriorated Pole or Pole Top Equipment ; Customers	43
3		FA 24TH AVE HUDSONVILLE - POL2	26	1	Project	Imminent Rehabilitation	OTTAWA	Replace Deteriorated Pole ; Customers	2
4		FA - 24TH AVE HUDSONVILLE - ESIC UGL	39	1	Project	Imminent Rehabilitation	OTTAWA	Replace Deteriorated Pole ; Customers	2
5		INSP NORTH LANSING_LABORATORY	60	1	Project	Imminent Rehabilitation	CLINTON	Replace Deteriorated Pole ; Customers	2
6		FA - CENTER ST MICHIGAN CENTER	45	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	1
7		FA - BIRCH ST, BRECKENRIDGE; SVLT	70	1	Project	Imminent Rehabilitation	GRATIOT	Improve Secondary Voltage ; Customers	24
8		FA-BAYVIEW,MGN-VOLTAGE CHARTS	18	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	43
9		FA Crestwood LN NORTON_HILE ROAD	103	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
10		FA - HOLTON RD, HOLTON - MRC1	5	1	Project	Imminent Rehabilitation	MUSKEGON	Attachment Clearance Violation ; Customers	43
11		FA - BYRON RD, ZEELAND - POL2	6	1	Project	Imminent Rehabilitation	OTTAWA	Replace Deteriorated Pole ; Customers	2
12		FA BRANDYWYNE DR NW-SVLT	94	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	1
13		FA - N F 41, LCLN; SEC CLEARANCE	5	1	Project	Imminent Rehabilitation	ALCONA	Correct Conductor Clearance Violation ; Customers	520
14		FA E DELLAR RD REG ESIC	44	1	Project	Imminent Rehabilitation	ALCONA	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
15		FA - Ashman Circle-Sugnet - PVLT	28	1	Project	Imminent Rehabilitation	MIDLAND	Improve Primary Voltage ; Customers	58
16		S SAGINAW RD, UNIT 3, ESIC OHS	6	1	Project	Imminent Rehabilitation	MIDLAND	Replace Deteriorated Pole or Pole Top Equipment ; Customers	20
17		S SAGINAW RD, UNIT 3, ESIC OHL	8	1	Project	Imminent Rehabilitation	MIDLAND	Replace Deteriorated Pole or Pole Top Equipment ; Customers	43
18		FA - WILLIAMS ST, HOWARD CITY - SVLT	37	1	Project	Imminent Rehabilitation	MONTCALM	Improve Secondary Voltage ; Customers	5
19		FA Pierson_Pierson Sandlake Line Reloc	75	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole ; Customers	58
20		FA-HARRISON HARRISON LCP 5883	122	1	Project	Imminent Rehabilitation	CLARE	Replace Deteriorated Pole ; Customers	5
21		FA - Norton Center Dr, MUS-PFCP UGL	397	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Underground Primary ; Customers	2
22		FA LIME LAKE DR, Sparta - ESIC OHL	67	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
23		FA LIME LAKE DR, Sparta - OHS	5	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
24		FA - Lupine Ct - SVLT	13	1	Project	Imminent Rehabilitation	BAY	Improve Secondary Voltage ; Customers	520
25		INSP KAWKAWLIN WHEELER POLE	5	1	Project	Imminent Rehabilitation	BAY	Replace Deteriorated Pole ; Customers	24
26		FA HICKORY RD FRUITPORT SVLT	10	1	Project	Imminent Rehabilitation	OTTAWA	Improve Secondary Voltage ; Customers	2
27		INSP LIBERTY_WASHINGTON_POLES	42	1	Project	Imminent Rehabilitation	CALHOUN	Replace Deteriorated Pole ; Customers	24
28		W MICHIGAN AVE BCK-ESIC STL	12	1	Project	Imminent Rehabilitation	CALHOUN	Repair Damaged Streetlight ; Customers	2
29		CRITICAL FA BOMAN_DELAND LCP 391	41	1	Project	Imminent Rehabilitation	GENESEE	Replace Deteriorated Pole or Pole Top Equipment ; Customers	520
30		FA OJ MORSE DR PCFP	203	1	Project	Imminent Rehabilitation	NEWAYGO	Improve Secondary Voltage ; Customers	242
31		FA-Starks Lee AB 839	31	1	Project	Imminent Rehabilitation	MIDLAND	Replace Deteriorated Pole or Pole Top Equipment ; Customers	155
32		FA - E SUPERIOR ST, ALMA; ODCE	37	1	Project	Imminent Rehabilitation	GRATIOT	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	2
33		FA - CASS ST, SAG; OHC1	17	1	Project	Imminent Rehabilitation	SAGINAW	Correct Conductor Clearance Violation ; Customers	5
34		FA GARLAND ST SE - volt comp	76	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	242
35		FA Wood St SVLT - ESIC OHL	86	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
36		FA-BROWN RD-SVLT-LKLEANN-BUNDYHILL-	57	1	Project	Imminent Rehabilitation	HILLSDALE	Improve Secondary Voltage ; Customers	242
37		FA - CARLOS AVE, ROSCOMMON; OHC2	6	1	Project	Imminent Rehabilitation	ROSCOMMON	Correct Conductor Clearance Violation ; Customers	242
38		FA -W SUNSET DR, ROSCOMMON - OHC2	13	1	Project	Imminent Rehabilitation	ROSCOMMON	Correct Conductor Clearance Violation ; Customers	5
39		FA Whitehall Rd- OHPE	43	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
40		FA - Duck Lake Rd Loc 1-2	19	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	242
41		FA S VILLAGE DR, WILL PFCP	125	1	Project	Imminent Rehabilitation	GRAND TRAVERS	Replace Deteriorated Underground Primary ; Customers	520
42		FA - BECKER_BEAR CREEK - ROBERTS RD	35	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	242
43		ESO OHS - FA - BECKER_BEAR CREEK	5	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	24
44		FA - Aloha Ave Low Voltage - SVLT	74	1	Project	Imminent Rehabilitation	CALHOUN	Improve Secondary Voltage ; Customers	5
45		FA-W KENT RD, Wheeler -PVLT	25	1	Project	Imminent Rehabilitation	MIDLAND	Improve Primary Voltage ; Customers	5
46		FA - INDIAN RIVER_RONDO LCP 922	6	1	Project	Imminent Rehabilitation	CHEBOYGAN	Improve Secondary Voltage ; Customers	2
47		FA INDIAN RIVER_TOPINABEE LCP 262	38	1	Project	Imminent Rehabilitation	CHEBOYGAN	Replace Deteriorated Switch ; Customers	24
48		FA - S WASHINGTON RD, DOUGLAS - ODCE	37	1	Project	Imminent Rehabilitation	ALLEGAN	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	20
49		FA - S PIERCE RD WHT CLD - PVLT	23	1	Project	Imminent Rehabilitation	NEWAYGO	Improve Primary Voltage ; Customers	2
50		FA GLEN LAKE/HOMESTEAD LCP 8323	7	1	Project	Imminent Rehabilitation	LEELANAU	Retire and Remove Unused Assets; Customers	1
51		CRITICAL FL GLEN LK HOMESTEAD LCP929 UGL	160	1	Project	Imminent Rehabilitation	LEELANAU	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
52		FA GLEN LAKE/HOMESTEAD LCP521 ESIC	275	1	Project	Imminent Rehabilitation	LEELANAU	Replace Deteriorated Underground Primary ; Customers	5
53		CRITICAL FL GLEN LK HOMESTEAD LCP929 OLH	125	1	Project	Imminent Rehabilitation	LEELANAU	Replace Deteriorated Pole or Pole Top Equipment ; Customers	242
54		CRITICAL FL GLEN LK HOMESTEAD LCP931 UGL	255	1	Project	Imminent Rehabilitation	LEELANAU	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
55		FA - E DYER RD, PRESCOTT - RREG	4	1	Project	Imminent Rehabilitation	OGEMAW	Replace Deteriorated Regulator ; Customers	5
56		FA_SVLT_ABBOTT RD_ROSE CITY	7	1	Project	Imminent Rehabilitation	OSCODA	Improve Secondary Voltage ; Customers	24
57		FA_SVLT_ISLAND LAKE RD_ROSE CITY	14	1	Project	Imminent Rehabilitation	OSCODA	Improve Secondary Voltage ; Customers	5
58		FA - N WILLIAM ST	5	1	Project	Imminent Rehabilitation	MASON	Replace Deteriorated Underground Primary ; Customers	2
59		FA ALDEN_CLAM LCP605 LEANING POLE	18	1	Project	Imminent Rehabilitation	ANTRIM	Replace Deteriorated Pole or Pole Top Equipment ; Customers	43
60		FA - OTTAWA AVE NW - POL2	4	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole ; Customers	2
61		**Imminent Rehabilitation Subtotal**	**3,235**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA - AUBURN_AUBURN LCP 648, PVLT	84	1	Project	Imminent Rehabilitation	BAY	Improve Primary Voltage ; Customers	520
2		CRITICAL FL - PARKDALE AVE - MANISTE	45	1	Project	Imminent Rehabilitation	MANISTEE	Replace Deteriorated Pole or Pole Top Equipment ; Customers	24
3		FA Baldwin_Idlewild LCP 423 Regs	39	1	Project	Imminent Rehabilitation	LAKE	Replace Deteriorated Pole or Pole Top Equipment ; Customers	520
4		FA Cambridge Blvd SE low voltage	34	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	242
5		FA Lakeside Dr SE - EGR-critical toFL	46	1	Project	Imminent Rehabilitation	KENT	Deteriorated Service Replacement ; Customers	2
6		FA OAKWOOD DR SE, GR - ADD TRF	127	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	242
7		INSP 116TH AVE POLE RLCT OHL	135	1	Project	Imminent Rehabilitation	ALLEGAN	Replace Deteriorated Pole ; Customers	5
8		INSP 116TH AVE POLE RELOCATE UGL	26	1	Project	Imminent Rehabilitation	ALLEGAN	Replace Deteriorated Pole ; Customers	242
9		ADARIDGE DR SE Relocate ESIC OHL	44	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	43
10		FA Hemlock Hemlock LCP807	9	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
11		FA - Presidential - SVLT	21	1	Project	Imminent Rehabilitation	CALHOUN	Improve Secondary Voltage ; Customers	5
12		FA - CENTER ST, PLAINWELL - OHC2	5	1	Project	Imminent Rehabilitation	BARRY	Correct Conductor Clearance Violation ; Customers	5
13		REHAB BISHOP-MARKET PLACE LCP 603	44	1	Project	Imminent Rehabilitation	GENESEE	Replace Deteriorated Underground Primary ; Customers	5
14		FA N US 31 N STE D SVLT	10	1	Project	Imminent Rehabilitation	GRAND TRAVERSE	Improve Secondary Voltage ; Customers	58
15		FA N US 31 N STE D SVLT - OHS	5	1	Project	Imminent Rehabilitation	GRAND TRAVERSE	Improve Secondary Voltage ; Customers	242
16		FA-MAIN EAST JORDAN-SVLT	31	1	Project	Imminent Rehabilitation	CHARLEVOIX	Improve Secondary Voltage ; Customers	5
17		FA - HOGAN RD, GAINES - OHC2	6	1	Project	Imminent Rehabilitation	GENESEE	Correct Conductor Clearance Violation ; Customers	2
18		FA Stevens_Albany low voltage Graham	20	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	2
19		FA US HWY 10 LCP 674 VOLT SVLT - ESIC	30	1	Project	Imminent Rehabilitation	MASON	Improve Secondary Voltage ; Customers	5
20		FA - Brye Rd Scottville Tie Switch 469T	14	1	Project	Imminent Rehabilitation	MASON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	242
21		CMPLT - BAY ST, SGN; ODCE	95	1	Project	Imminent Rehabilitation	SAGINAW	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	520
22		FA - DELAWARE BLVD SAG ; SVLT	32	1	Project	Imminent Rehabilitation	SAGINAW	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	5
23		FA - YORK DR, SAGINAW - POLES	32	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Pole ; Customers	0
24		FA AB LCP 320 INST REG LAING LELAND	16	1	Project	Imminent Rehabilitation	SHIAWASSEE	Replace Deteriorated Regulator ; Customers	2
25		FA - N SHORE DR, LAKE - POL2	27	1	Project	Imminent Rehabilitation	CLARE	Replace Deteriorated Pole ; Customers	2
26		FA - N ALGER RD, ALMA; POL2	14	1	Project	Imminent Rehabilitation	GRATIOT	Replace Deteriorated Pole ; Customers	5
27		FA-JEFFERSON,MGN-TRF CUT IN NEEDED	15	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	24
28		FA Henry st Norton Shores	14	1	Project	Imminent Rehabilitation	MUSKEGON	Repair Hole in Padmount Enclosure ; Customers	2
29		FA - AUTUMN RDG, SGN - SVLT	7	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	12
30		FA - LINCOLN AVE NW GRAND RAPIDS	25	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
31		FA - RAY ST MUS - SVLT - POLE	75	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole ; Customers	20
32		FA - RAY ST MUS - POLE	5	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
33		FA - 46TH ST, ALLEGAN - OHC1	3	1	Project	Imminent Rehabilitation	ALLEGAN	Correct Conductor Clearance Violation ; Customers	5
34		FA - S LINCOLN RD MT PLEASANT - DSRV	9	1	Project	Imminent Rehabilitation	ISABELLA	Deteriorated Service Replacement ; Customers	2
35		HOSPITAL_KIDS CREEK TLM	9	1	Project	Imminent Rehabilitation	GRAND TRAVERSE	Improve Secondary Voltage ; Customers	5
36		FA-Cable Replacement Hill Brady LCP 259	240	1	Project	Imminent Rehabilitation	CALHOUN	Replace Deteriorated Underground Primary ; Customers	5
37		FA-Cable Replacement Hill Brady A2	269	1	Project	Imminent Rehabilitation	CALHOUN	Replace Deteriorated Pole or Pole Top Equipment ; Customers	
38		FA-Cable Replacement Hill Brady A3	165	1	Project	Imminent Rehabilitation	CALHOUN	Replace Deteriorated Pole or Pole Top Equipment ; Customers	
39		FA VOLT ISLAND HWY CHT ESIC OHL	14	1	Project	Imminent Rehabilitation	EATON	Improve Secondary Voltage ; Customers	5
40		FA BAGLEY_OTSEGO LAKE LCP SUB #2	270	1	Project	Imminent Rehabilitation	OTSEGO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	24
41		FA - STONEWOOD ST, GYLD SVLT	37	1	Project	Imminent Rehabilitation	OTSEGO	Improve Secondary Voltage ; Customers	2
42		FA-WHITE RD-CARY_JEFFERSON-LOW VOLTA	11	1	Project	Imminent Rehabilitation	JACKSON	Improve Secondary Voltage ; Customers	2
43		SYSP HARRIET_HARRIET LCP 607	24	1	Project	Imminent Rehabilitation	GENESEE	Improve Secondary Voltage ; Customers	43
44		FA - N SCHEURMANN RD - DEMO	5	1	Project	Imminent Rehabilitation	BAY	Improve Secondary Voltage ; Customers	5
45		FA - N SCHEURMANN RD - SVLT	27	1	Project	Imminent Rehabilitation	BAY	Improve Secondary Voltage ; Customers	5
46		FA Whitebirch Dr SVLT Part 2	16	1	Project	Imminent Rehabilitation	MONTCALM	Improve Secondary Voltage ; Customers	5
47		FA Calvin Beltline LCP 416 - UGL 2320	23	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Underground Primary ; Customers	2
48		FA - IRONWOOD RD, ROSCOMMON - DSRV	50	1	Project	Imminent Rehabilitation	ROSCOMMON	Deteriorated Service Replacement ; Customers	2
49		FA-SAGINAW LEGION DR RCMN_VOLTAGE*RC	129	1	Project	Imminent Rehabilitation	ROSCOMMON	Improve Secondary Voltage ; Customers	520
50		FA S HURON ST voltage charts	57	1	Project	Imminent Rehabilitation	CHEBOYGAN	Improve Secondary Voltage ; Customers	155
51		FA S HURON ST voltage charts-OHS	5	1	Project	Imminent Rehabilitation	CHEBOYGAN	Improve Secondary Voltage ; Customers	12
52		INSP LEFFINGWELL_MICHIGAN OAKS 338 P14	77	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole ; Customers	520
53		FA - LITTLEFIELD DR NE GR	3	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole ; Customers	58
54		FA - N WEBSTER RD - OHC2	8	1	Project	Imminent Rehabilitation	GENESEE	Correct Conductor Clearance Violation ; Customers	2
55		FA - 146TH AVE, HOLLAND - ESIC OHL	13	1	Project	Imminent Rehabilitation	ALLEGAN	Correct Conductor Clearance Violation ; Customers	43
56		GARFIELD RD CARWASH, FREELAND	58	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Underground Primary ; Customers	2
57		FA - E WASHINGTON RD, FLND	8	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Pole or Pole Top Equipment ; Customers	155
58		FA 154th st AGNEW_WEYBURN OHL	10	1	Project	Imminent Rehabilitation	OTTAWA	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
59		**Imminent Rehabilitation Subtotal**	**2,667**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

Case No.: U-22070
Exhibit No.: A-167 (JMP-1)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA - N 6TH ST KALAMAZOO-guying	10	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole ; Customers	5
2		FA-ARROWHEAD,W BRANCH-SVLT	12	1	Project	Imminent Rehabilitation	OGEMAW	Improve Secondary Voltage ; Customers	43
3		STL-Eastlawn Dr,Midland ESIC OHL	11	1	Project	Imminent Rehabilitation	MIDLAND	Repair Damaged Streetlight ; Customers	2
4		FA -SALZBURG AND 8 MILE, ABRN, POL2	78	1	Project	Imminent Rehabilitation	BAY	Replace Deteriorated Pole ; Customers	242
5		FA BAILEY HALF MOON LAKE FLRE	47	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	520
6		FA - 2340 MERSHON ST, SAG; SVLT	53	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	242
7		FA W Holton SVLT - ESIC RLU	25	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	1
8		FA - BEECHNUT-HOLAGAN PVLT BLUE STAR HWY	22	1	Project	Imminent Rehabilitation	ALLEGAN	Improve Primary Voltage ; Customers	2
9		FA -42ND ST, HAMILTON - POL2 - NEW	9	1	Project	Imminent Rehabilitation	ALLEGAN	Replace Deteriorated Pole ; Customers	20
10		FA- PAW PAW DR, HOLLAND-OHC2	13	1	Project	Imminent Rehabilitation	OTTAWA	Correct Conductor Clearance Violation ; Customers	2
11		FA VOLT E US 223, BLISSFIELD	6	1	Project	Imminent Rehabilitation	LENAWEE	Improve Secondary Voltage ; Customers	5
12		FA - 68TH ST - OHC1	12	1	Project	Imminent Rehabilitation	ALLEGAN	Correct Conductor Clearance Violation ; Customers	2
13		FA - DALLAS AVE SE, GR - SVLT	53	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
14		FA-CALVIN SE, GR-OHC2	5	1	Project	Imminent Rehabilitation	KENT	Correct Conductor Clearance Violation ; Customers	2
15		FA-CALVIN SE, GR-OHC2 ESIC OHS	5	1	Project	Imminent Rehabilitation	KENT	Correct Conductor Clearance Violation ; Customers	5
16		FA - BIRCHCREST DR - PFCP	55	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Underground Primary ; Customers	1
17		FA - SHERIDAN RD, SAGINAW - OHC2	9	1	Project	Imminent Rehabilitation	SAGINAW	Correct Conductor Clearance Violation ; Customers	520
18		FA Calvin Beltline LCP 416	32	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Underground Primary ; Customers	2
19		FA - CARROLLTON_CARROLLTON LCP 909; PVLT	12	1	Project	Imminent Rehabilitation	SAGINAW	Improve Primary Voltage ; Customers	5
20		FA-US12-CARY_WOODSTOCK-LOW VOLTAGE	9	1	Project	Imminent Rehabilitation	LENAWEE	Improve Secondary Voltage ; Customers	43
21		FA Cascade Peace Oakbrook St	12	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	43
22		FA-RAINTREE BLVD AT FINLEY RD_Bad URD	537	1	Project	Imminent Rehabilitation	ST JOSEPH	Replace Deteriorated Underground Primary ; Customers	5
23		FA - CHAUNCEY-AUSTIN LCP 549 - HPMT	65	1	Project	Imminent Rehabilitation	CALHOUN	Repair Hole in Padmount Enclosure ; Customers	5
24		FA-CHIPPING NORTON CT, SAGINAW-SVLT	7	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
25		FA - MIDWAY ST, SAGINAW - SVLT	55	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	242
26		FA -E LUDINGTON, CLARE- UGL - PFCP	54	1	Project	Imminent Rehabilitation	CLARE	Replace Deteriorated Underground Primary ; Customers	2
27		FA - E OP AVE CLIMAX	17	1	Project	Imminent Rehabilitation	KALAMAZOO	Retire and Remove Unused Assets; Customers	242
28		FA VOLT ISLAND HWY CHT ECNC RSU	23	1	Project	Imminent Rehabilitation	EATON	Improve Secondary Voltage ; Customers	5
29		FA 16 Mile Rd	8	1	Project	Imminent Rehabilitation	CALHOUN	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
30		FA FLRE Derby_Derby OHL	55	1	Project	Imminent Rehabilitation	MONTCALM	Replace Deteriorated Pole ; Customers	2
31		FA - N GROW RD, STANTON - OHC2	5	1	Project	Imminent Rehabilitation	MONTCALM	Correct Conductor Clearance Violation ; Customers	5
32		FA FLRE Derby_Derby UGL BORE	102	1	Project	Imminent Rehabilitation	MONTCALM	Replace Deteriorated Pole ; Customers	12
33		FA-68TH SE,CALEDONIA-CUT IN TRF	7	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	2
34		FA AULERICH RD ETAW ESIC OHL	4	1	Project	Imminent Rehabilitation	IOSCO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
35		FA - EASTLAWN_FLAJOLE LCP 530	4	1	Project	Imminent Rehabilitation	MIDLAND	Replace Deteriorated Pole ; Customers	24
36		FA - E VAN BUREN RD, WHEELER - SVLT	13	1	Project	Imminent Rehabilitation	GRATIOT	Improve Secondary Voltage ; Customers	2
37		FA- N EDGAR RD, SIX LAKES - POL2	3	1	Project	Imminent Rehabilitation	MONTCALM	Replace Deteriorated Pole ; Customers	43
38		FA - HILLCREST LAKE - VOLT ISSUE	43	1	Project	Imminent Rehabilitation	CLARE	Improve Secondary Voltage ; Customers	5
39		FA-W CO LINE, HOWARD CITY-SVLT	25	1	Project	Imminent Rehabilitation	MONTCALM	Improve Secondary Voltage ; Customers	5
40		FA -W HAMPTON RD, ESSEX; POL2	5	1	Project	Imminent Rehabilitation	BAY	Replace Deteriorated Pole ; Customers	242
41		FA-LOW NEUTRAL GORMAN & M-52	5	1	Project	Imminent Rehabilitation	LENAWEE	Correct Conductor Clearance Violation ; Customers	24
42		FA - 27th St Voltage Complaints - SVLT	113	1	Project	Imminent Rehabilitation	CALHOUN	Improve Secondary Voltage ; Customers	5
43		FA-VETERANS MEMORIAL, SAG; OHC2-OH	53	1	Project	Imminent Rehabilitation	SAGINAW	Correct Conductor Clearance Violation ; Customers	5
44		FA - SPRING ST, ALAN - OHC1	82	1	Project	Imminent Rehabilitation	EMMET	Correct Conductor Clearance Violation ; Customers	5
45		CRITICAL FA -MCCAMLY AND HOUSTON ST BC	11	1	Project	Imminent Rehabilitation	CALHOUN	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
46		FA - PARTRIDGE ST, FLINT-SVLT	120	1	Project	Imminent Rehabilitation	GENESEE	Improve Secondary Voltage ; Customers	24
47		FA S SHORE W FRANKFORT UGL	36	1	Project	Imminent Rehabilitation	BENZIE	Improve Secondary Voltage ; Customers	2
48		FA W WALNUT ST FREMONT SVLT	51	1	Project	Imminent Rehabilitation	NEWAYGO	Improve Secondary Voltage ; Customers	24
49		FA S Walker, Fruitport-Upgrade	7	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
50		FA apple dr fruitport	24	1	Project	Imminent Rehabilitation	OTTAWA	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
51		FA PFCP Argyle-Camelot Villas UGL	175	1	Project	Imminent Rehabilitation	GENESEE	Replace Deteriorated Underground Primary ; Customers	2
52		FA - W BURDELL RD, ROSCOMMON - OHC2	19	1	Project	Imminent Rehabilitation	ROSCOMMON	Correct Conductor Clearance Violation ; Customers	12
53		FA - GERRISH/COTTAGE GROVE NEW REG; PVLT	35	1	Project	Imminent Rehabilitation	ROSCOMMON	Improve Primary Voltage ; Customers	12
54		FA Brusse Ave - RLO	75	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole ; Customers	242
55		FA - E THOMAS ST, PARCHMENT	4	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole ; Customers	2
56		FA GLENDALE_HERCULES Mt Olivet Rd	119	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	2
57		FA - S WISNER AVE, GRANT - FRRE	10	1	Project	Imminent Rehabilitation	NEWAYGO	Retire and Remove Unused Assets; Customers	242
58		FA - KATE DR, GRAYLING - FLRE	19	1	Project	Imminent Rehabilitation	CRAWFORD	Replace Deteriorated Pole or Pole Top Equipment ; Customers	155
59		FA - W LAKESIDE, WEST BRANCH - SVLT	6	1	Project	Imminent Rehabilitation	OGEMAW	Improve Secondary Voltage ; Customers	242
60		FA - CROSS LN, HAMILTON - PVLT	220	1	Project	Imminent Rehabilitation	ALLEGAN	Improve Primary Voltage ; Customers	242
61		**Imminent Rehabilitation Subtotal**	**2,706**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Bridge Period LVD Project List
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($000)

Case No.: U-22070
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA-MOSCOW RD-HANOVER_HORTON-LOW VOLT	11	1	Project	Imminent Rehabilitation	JACKSON	Improve Secondary Voltage ; Customers	5
2		FA - S 2ND ST, HARRISON - OHC2	17	1	Project	Imminent Rehabilitation	CLARE	Correct Conductor Clearance Violation ; Customers	1
3		FA - BANKS LAKE RD, GOWEN-SVLT-OH	68	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
4		FA-STACEY WOODS NE,GVL-SVLT	20	1	Project	Imminent Rehabilitation	MONTCALM	Improve Secondary Voltage ; Customers	5
5		FA Stultz St NE	11	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
6		FA - WOODMERE AVE SE, GR - SVLT_OHL	184	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
7		FA_N REED RD HOWARD CITY	57	1	Project	Imminent Rehabilitation	MONTCALM	Replace Deteriorated Pole or Pole Top Equipment ; Customers	242
8		FA - E REARDON ST, MDL; POL2	6	1	Project	Imminent Rehabilitation	MIDLAND	Replace Deteriorated Pole ; Customers	2
9		JEFFERSON AVE, MDL, ESIC OHS	5	1	Project	Imminent Rehabilitation	MIDLAND	Deteriorated Service Replacement ; Customers	5
10		FA GREEN ST, GRAND HAVEN	15	1	Project	Imminent Rehabilitation	OTTAWA	Replace Deteriorated Pole or Pole Top Equipment ; Customers	242
11		FA-1 1/2 Mile s/o E-Dr-S-OHC1	30	1	Project	Imminent Rehabilitation	CALHOUN	Correct Conductor Clearance Violation ; Customers	43
12		FA KALARAMA_ROMENCE LCP 770 ESIC OHL	50	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
13		FA - RAY ST MUS - SVLT	79	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	43
14		FA - KNIGHT_FARLEY LCP 809J REGS; PVLT	23	1	Project	Imminent Rehabilitation	BAY	Improve Primary Voltage ; Customers	1
15		FA CRANSON RD BRN	40	1	Project	Imminent Rehabilitation	BRANCH	Replace Deteriorated Pole or Pole Top Equipment ; Customers	20
16		FA-Kraft Sysco - 36th St SE	18	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Underground Primary ; Customers	5
17		FA-RALEIGH SE,GR-UPGRADE TRF	10	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	1
18		FA - Plainfield Ave	75	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
19		FA-N F 41 LCLN VOLT24-SVLT	15	1	Project	Imminent Rehabilitation	ALCONA	Improve Secondary Voltage ; Customers	43
20		FA MACKINAW CITY_POND STREET LCP 509	10	1	Project	Imminent Rehabilitation	EMMET	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
21		FA-MINER RD PARMA-SVLT	31	1	Project	Imminent Rehabilitation	JACKSON	Improve Secondary Voltage ; Customers	5
22		FA-WALLACE NE,MANCELONA-RELOC GUY	10	1	Project	Imminent Rehabilitation	KALKASKA	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	5
23		FA W Manahan Ave Muskegon	75	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	12
24		FA W Norton Ave MAPLE GROVE_HENRY S	59	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
25		FA-LONG PT,HOUGHTON LK-SVLT	26	1	Project	Imminent Rehabilitation	ROSCOMMON	Improve Secondary Voltage ; Customers	2
26		FA - LONG POINT DR, HTNL - POLE	5	1	Project	Imminent Rehabilitation	ROSCOMMON	Replace Deteriorated Pole ; Customers	5
27		FA - AMMAN RD, CHESANING; OHC2	6	1	Project	Imminent Rehabilitation	SAGINAW	Correct Conductor Clearance Violation ; Customers	2
28		FA - E RIVER RD, MUSKEGON - SVLT	11	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	2
29		FA-HOLTON RD RAYS MINI MART - SVLT	36	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	2
30		FA Meadowbrook Karaona - Kraft Ave	14	1	Project	Imminent Rehabilitation	KENT	Correct Conductor Clearance Violation ; Customers	2
31		FA MISSION ST & APPIAN WAY MT PLEASANT	131	1	Project	Imminent Rehabilitation	ISABELLA	Replace Deteriorated Pole or Pole Top Equipment ; Customers	43
32		FA - N ROSE ST, KALAMAZOO - POL2	11	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole ; Customers	24
33		FA MT PLEASANT COLLEGE LCP 481	18	1	Project	Imminent Rehabilitation	ISABELLA	Replace Deteriorated Pole or Pole Top Equipment ; Customers	1
34		FA - MURNER_VAN TYLE LCP 325 NOTTINGHAM	115	1	Project	Imminent Rehabilitation	OTSEGO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	1
35		FA - BARD RD WHITEHALL - SVLT OHL	12	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
36		FA -62ND ST, SAUGATUCK - SVLT***	10	1	Project	Imminent Rehabilitation	ALLEGAN	Improve Secondary Voltage ; Customers	5
37		FA - MAINE ST SGN; SVLT	48	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
38		FA Van Appel Dr	35	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole ; Customers	5
39		FA Oakmere PL N MUSKEGON_STATE PARK	34	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	242
40		FA - RIVERVIEW AVE, N MUSK - PFCP	8	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Underground Primary ; Customers	5
41		FA - FERDON RD, KZOO	32	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	5
42		FA ORIOLE BRYANT RD LCP 5355 - UGL	49	1	Project	Imminent Rehabilitation	MASON	Replace Deteriorated Underground Primary ; Customers	5
43		FA W LONG LAKE RD ORLEANS	36	1	Project	Imminent Rehabilitation	IONIA	Improve Secondary Voltage ; Customers	520
44		FA-DOUGLAS LAKE,PELLSTON-SVLT	17	1	Project	Imminent Rehabilitation	CHEBOYGAN	Improve Secondary Voltage ; Customers	520
45		FA PHILLIPS FACTORY MILLER RD	65	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	242
46		FA - W HILL ST, PLAINWELL - SVLT	71	1	Project	Imminent Rehabilitation	ALLEGAN	Improve Secondary Voltage ; Customers	242
47		FA - S Main St, Plainwell	58	1	Project	Imminent Rehabilitation	ALLEGAN	Deteriorated Secondary Conductor/ Equipment Replacement ; Customers	5
48		FA - BIRCHWOOD, RGC - SVLT OHL	14	1	Project	Imminent Rehabilitation	PRESQUE ISLE	Improve Secondary Voltage ; Customers	242
49		FA - SHAVER RD, PORTAGE	6	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	5
50		FA - ROBIN GLEN REBUILD PH. 1 - PFCP	62	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Underground Primary ; Customers	2
51		FA - BURNS RD MGER OHC2	95	1	Project	Imminent Rehabilitation	BAY	Correct Conductor Clearance Violation ; Customers	43
52		APPR FA - 113TH AVE, FENNVILLE-DSRV	54	1	Project	Imminent Rehabilitation	ALLEGAN	Deteriorated Service Replacement ; Customers	24
53		FA E Chicago Rd, Quincy	14	1	Project	Imminent Rehabilitation	HILLSDALE	Correct Padmount to Building Clearance Violation ; Customers	5
54		FA 5 MILE NE, LOWEEL - SVLT	10	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
55		FA LO AL Dr Ravenna	66	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	242
56		FA - LOOMIS ST, JACKSON - SVLT	18	1	Project	Imminent Rehabilitation	JACKSON	Improve Secondary Voltage ; Customers	24
57		FA Luca Vista Dr NE-SVLT	27	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
58		FA_LAKEVIEW ST_W BRANCH POL2	17	1	Project	Imminent Rehabilitation	OGEMAW	Replace Deteriorated Pole ; Customers	242
59		FA_ROSE CITY_KLACKING CREEK SWAMP POLE	8	1	Project	Imminent Rehabilitation	OGEMAW	Improve Primary Voltage ; Customers	5
60		FL CRIITICAL - LOON LAKE LOOP RSC	29	1	Project	Imminent Rehabilitation	OSCODA	Improve Primary Voltage ; Customers	5
61		**Imminent Rehabilitation Subtotal**	**2,188**						

MICHIGAN PUBLIC SERVICE COMMISSION
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($000)

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA_LAKEVIEW ST_W BRANCH 2411 RSO	5	1	Project	Imminent Rehabilitation	OGEMAW	Replace Deteriorated Pole ; Customers	5
2		FA_LAKEVIEW ST_W BRANCH 2421 RSO	5	1	Project	Imminent Rehabilitation	OGEMAW	Replace Deteriorated Pole ; Customers	43
3		FA - N State Rd SVLT	9	1	Project	Imminent Rehabilitation	GENESEE	Improve Secondary Voltage ; Customers	1
4		FA-TRAILS END DR, MIO-POL2	4	1	Project	Imminent Rehabilitation	OSCODA	Replace Deteriorated Pole ; Customers	2
5		FA-JOHNSON RD, SARANAC-SVLT	14	1	Project	Imminent Rehabilitation	IONIA	Improve Secondary Voltage ; Customers	5
6		FA - OUTER DR W,TC - OHC2	19	1	Project	Imminent Rehabilitation	GRAND TRAVERSE	Correct Conductor Clearance Violation ; Customers	5
7		FA - WOODLAND DR, SPRUCE - POL2	17	1	Project	Imminent Rehabilitation	ALCONA	Replace Deteriorated Pole ; Customers	5
8		FA - GREENLAWN AVE, KZOO	5	1	Project	Imminent Rehabilitation	KALAMAZOO	Correct Conductor Clearance Violation ; Customers	242
9		FA - RED PINE DR, STANWOOD - SVLT	15	1	Project	Imminent Rehabilitation	MECOSTA	Improve Secondary Voltage ; Customers	1
10		FA - AVALON AVE, SAGINAW - POL2	16	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Pole ; Customers	5
11		FA - W WESTOVER,E TAWAS - SVLT	24	1	Project	Imminent Rehabilitation	IOSCO	Improve Secondary Voltage ; Customers	5
12		FA - BRIANS WAY, CORAL - SVLT	5	1	Project	Imminent Rehabilitation	MONTCALM	Improve Secondary Voltage ; Customers	5
13		FA - UPTON_SIMMONS LCP 646 - FLRE	14	1	Project	Imminent Rehabilitation	EATON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	242
14		FA - IDAHO AVE @ NEVADA AVE, PORTAGE	120	1	Project	Imminent Rehabilitation	KALAMAZOO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	24
15		FA - N SAGINAW, FLINT - DSRV	5	1	Project	Imminent Rehabilitation	GENESEE	Deteriorated Service Replacement ; Customers	5
16		FA - E W AVE - SVLT	11	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	242
17		FA WARNER_BURCHETT	24	1	Project	Imminent Rehabilitation	ALLEGAN	Improve Secondary Voltage ; Customers	24
18		FA - TOWERLINE RD, HALE - SVLT	6	1	Project	Imminent Rehabilitation	IOSCO	Improve Secondary Voltage ; Customers	20
19		FA - SAVOY LN, SAGINAW - OHC2	43	1	Project	Imminent Rehabilitation	SAGINAW	Correct Conductor Clearance Violation ; Customers	20
20		FA - S BARTON ST WHT CLD - SVLT	23	1	Project	Imminent Rehabilitation	NEWAYGO	Improve Secondary Voltage ; Customers	43
21		FA-WELCH LAKE RD GRASS LAKE-POL2	6	1	Project	Imminent Rehabilitation	JACKSON	Replace Deteriorated Pole ; Customers	2
22		FA WILMOTT_WILMOTT	24	1	Project	Imminent Rehabilitation	ALLEGAN	Improve Secondary Voltage ; Customers	5
23		FA-N PETERSON RD,MUSK-SPLIT LOAD/UPGR	40	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	9
24		FA MAIN ST GAYLORD	35	1	Project	Imminent Rehabilitation	OTSEGO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	10
25		FA Hall Rd SVLT	20	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
26		FA 5TH ST, TWIN LAKE WIRE C1	9	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	8
27		FA - N 8 MILE RD, SANFORD OHC2	10	1	Project	Imminent Rehabilitation	MIDLAND	Correct Conductor Clearance Violation ; Customers	24
28		FA - N LAKE DR SANFORD	32	1	Project	Imminent Rehabilitation	MIDLAND	Improve Secondary Voltage ; Customers	5
29		FA - RANGER LAKE/GOODAR PHASE CORRECTION	15	1	Project	Imminent Rehabilitation	IOSCO	Correct Non-Standard Phasing	2
30		FA - SAGINAW AND WALDO ST_MDL; STRL	18	1	Project	Imminent Rehabilitation	MIDLAND	Reinstall Center Suspensed Streetlight	0
31		FA - ST HELEN_ARTESIA LCP 651 - PFCP	103	1	Project	Imminent Rehabilitation	OGEMAW	Replace Deteriorated Underground Primary ; Customers	43
32		FA - HUBBARD LK_MILLER RD LCP 269 - FLRE	70	1	Project	Imminent Rehabilitation	ALCONA	Replace Hard to Access Poles	2
33		FA - W CARTER, ST HELEN - OHC1	15	1	Project	Imminent Rehabilitation	ROSCOMMON	Correct Conductor Clearance Violation ; Customers	24
34		FA - HUNT,OSCODA-SVLT	32	1	Project	Imminent Rehabilitation	IOSCO	Improve Secondary Voltage ; Customers	5
35		FA - W DYER RD, TWINING - SVLT	32	1	Project	Imminent Rehabilitation	IOSCO	Improve Secondary Voltage ; Customers	5
36		FA - BENSON RD, TAWAS-SVLT	32	1	Project	Imminent Rehabilitation	IOSCO	Improve Secondary Voltage ; Customers	5
37		FA - E CHERYL LYNN LN – OHC2	65	1	Project	Imminent Rehabilitation	MIDLAND	Correct Conductor Clearance Violation ; Customers	24
38		**Imminent Rehabilitation Subtotal**	**940**						
39		**Imminent Rehabilitation Total**	**13,475**						
40	LVD Lines Rehabilitation	FLRE SUBSF HARRIETTA_CABERFAE	10	1	Project	Subsurface Transformer	WEXFORD	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	2
41		FLRE SUBSF SCHUSS MTN CHALET SUB	77	1	Project	Subsurface Transformer	ANTRIM	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	2
42		FLRE SUBSF PIGEON LAKE-PIGEON	152	1	Project	Subsurface Transformer	OTTAWA	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	2
43		FLRE SUBSF HASTINGS_BOLTWOOD LCP 0423	6	1	Project	Subsurface Transformer	BARRY	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	2
44		FLRE SUBSF TWELFTH STREET_WESTFIELD	4	1	Project	Subsurface Transformer	KALAMAZOO	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	5
45		FLRE SUBSF TWELFTH STREET_RUDGATE	17	1	Project	Subsurface Transformer	KALAMAZOO	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	5
46		FLRE SUBSF BUCHANAN-SANDY SHORES	320	1	Project	Subsurface Transformer	OTTAWA	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	242
47		FLRE SUBSF CADILLAC-BOND	22	1	Project	Subsurface Transformer	WEXFORD	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	242
48		FLRE SUBSF BOMAN COUTANT LCP 431	198	1	Project	Subsurface Transformer	GENESEE	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	5
49		FLRE SUBSF ROCKFORD_SUMMIT LCP 425	18	1	Project	Subsurface Transformer	KENT	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	2
50		FLRE SUBSF ROCKFORD_SUMMIT LCP 425 UGL	63	1	Project	Subsurface Transformer	KENT	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	2
51		FLRE SUBSF EASTWOOD_EAST	900	1	Project	Subsurface Transformer	KALAMAZOO	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	5
52		FLRE SUBSF NORTHPORT MANITOU	9	1	Project	Subsurface Transformer	LEELANAU	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	2
53		FLRE SUBSF VIRGINIA PARK-CASTLE	24	1	Project	Subsurface Transformer	ALLEGAN	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	242
54		FLRE SUBSF MIDDLEVILLE_LAFAYETTE LCP0905	18	1	Project	Subsurface Transformer	BARRY	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	2
55		FLRE SUBSF SHANTY CREEK_EAST POINT	29	1	Project	Subsurface Transformer	ANTRIM	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	5
56		FLRE SUBSF SEIDEL_BROCKWAY	29	1	Project	Subsurface Transformer	SAGINAW	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	2
57		FLRE SUBSF CASCADE_THORNCREST LCP 337	29	1	Project	Subsurface Transformer	KENT	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	2
58		FLRE SUBSF SCHUSS MOUNTAIN_PUMP LCP 222	15	1	Project	Subsurface Transformer	ANTRIM	Deteriorated Underground Conductor/ Equipment Replacement ; Cu	10
59		**Subsurface Transformers Total**	**1,940**						
60	LVD Lines Rehabilitation	Modem Replacements	**2,998**	800	Modems	Modem Replacement	STATEWIDE	Avoid Obsolescence	
61	LVD Lines Rehabilitation	Meter Voltage Anomalies	**15,392**	N/A		Meter Voltage Anomalies	STATEWIDE	Regulatory Compliance	
62		**LVD Lines Rehabilitation Total**	**33,805**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Resiliency	EASTWOOD_TEXEL	2,636	2.3	miles	Vulnerable Communities	Kalamazoo	Customer-outage-minutes avoided	299,815
2		MOSEL_ALLEN	2,636	2.3	miles	Vulnerable Communities	Kalamazoo	Customer-outage-minutes avoided	270,203
3		MAYNARD_BESTWALL	3,781	3.3	miles	Vulnerable Communities	Kent Co.	Customer-outage-minutes avoided	79,265
4		EAST MUSKEGON_Q.LINE	2,409	2.8	miles	Vulnerable Communities	Muskegon Co.	Customer-outage-minutes avoided	255,841
5		MAPLE GROVE_SUMMIT AVE	2,519	2.6	miles	Vulnerable Communities	Muskegon Co.	Customer-outage-minutes avoided	187,951
6		MONA LAKE_AIRPORT	3,381	3.3	miles	Vulnerable Communities	Muskegon Co.	Customer-outage-minutes avoided	167,799
7		COMSTOCK_SHEILDS	2,752	3.1	miles	Vulnerable Communities	Kalamazoo	Customer-outage-minutes avoided	744,734
8		GOGUAC_LAKEVIEW	2,321	2.2	miles	Vulnerable Communities	Calhoun	Customer-outage-minutes avoided	160,153
9		MAUMEE_MAPLE STREET	2,277	1.9	miles	Vulnerable Communities	Lenawee	Customer-outage-minutes avoided	483,186
10		WEALTHY STREET_NORTHWEST	2,521	2.2	miles	Vulnerable Communities	Grand Rapids	Customer-outage-minutes avoided	189,401
11		ROBERTS ST_LEROY STREET	2,766	2.1	miles	Vulnerable Communities	Jackson	Customer-outage-minutes avoided	211,673
12		**Vulnerable Communities Total**	**30,000**						
13	Resiliency	BENNINGTON	2,580	1	Project	Resiliency - Fractionalization	Shiawasee Co.	Reliability - outage minutes avoided	76,750
14		EAGLE	5,190	0	Project	Resiliency - Fractionalization	Ottawa	Reliability - outage minutes avoided	-
15		MOBILE 27	1,810	0	Project	Resiliency - Fractionalization	Statewide	Reliability - outage minutes avoided	-
16		PRESCOTT	4,905	0	Project	Resiliency - Fractionalization	Ogemaw	Reliability - outage minutes avoided	-
17		COTTAGE GROVE	400	0	Project	Resiliency - Fractionalization	Bay	Reliability - outage minutes avoided	-
18		KENT CITY	675	0	Project	Resiliency - Fractionalization	Kent	Reliability - outage minutes avoided	-
19		WOLF LAKE	195	0	Project	Resiliency - Fractionalization	Van Buren	Reliability - outage minutes avoided	-
20		ROSE CITY	160	1	Project	Resiliency - Fractionalization	Ogemaw Co.	Reliability - outage minutes avoided	4,336
21		LINCOLN	4,380	1	Project	Resiliency - Fractionalization	Alcona Co.	Reliability - outage minutes avoided	688,017
22		EAST TAWAS	120	0	Project	Resiliency - Fractionalization	Iosco Co.	Reliability - outage minutes avoided	-
23		EDGEWOOD	55	1	Project	Resiliency - Fractionalization	Gratiot Co.	Reliability - outage minutes avoided	29,461
24		**Fractionalization Total**	**20,470**	**4**					
25	Resiliency	Butterfield_Linden_60	554	1.4	miles	Overhead to Underground	Newaygo Co.	Customer-outage-minutes avoided	25,080
26		Blackman_Sandstone_404	994	2.5	miles	Overhead to Underground	Jackson Co.	Customer-outage-minutes avoided	181,206
27		Eleventh Street_Baseline_268	1,314	3.3	miles	Overhead to Underground	Kalamazoo Co.	Customer-outage-minutes avoided	53,410
28		Lake Leann_Bundy Hill_473	834	2.1	miles	Overhead to Underground	Hillsdale Co.	Customer-outage-minutes avoided	45,383
29		Trufant_Gowen_847	550	1.4	miles	Overhead to Underground	Kent Co.	Customer-outage-minutes avoided	64,962
30		Squire Hill_Edgewater 776	314	0.8	miles	Overhead to Underground	Genesee Co	Customer-outage-minutes avoided	7,831
31		**Overhead to Underground**	**4,560**						
32		**Resiliency Total**	**55,030**						

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	Capacity								
1	LVD Lines Capacity	DARE RIDGE RD CAVANAUGH LK - OH	317	1	Project	Overloaded Equipment Upgrades	SYLVAN	Overload Failure Reduction; Customers	84
2		DARE BROOKLYN/BROOKLYN	76	1	Project	Overloaded Equipment Upgrades	BROOKLYN	Overload Failure Reduction; Customers	59
3		DARE MT PLEASANT/COLLEGE LCP 980	182	1	Project	Overloaded Equipment Upgrades	MOUNT PLEASANT	Overload Failure Reduction; Customers	309
4		DARE PINE RIVER/RURAL LCP 219	134	1	Project	Overloaded Equipment Upgrades	ALMA	Overload Failure Reduction; Customers	93
5		DARE ISABELLA/PICKARD LCP 789	17	1	Project	Overloaded Equipment Upgrades	MOUNT PLEASANT	Overload Failure Reduction; Customers	209
6		DARE MIDDLETON/MIDDLETON LCP 954	26	1	Project	Overloaded Equipment Upgrades	MIDDLETON	Overload Failure Reduction; Customers	218
7		DARE FENNVILLE/COMMERCIAL	758	1	Project	Overloaded Equipment Upgrades	CLYDE	Overload Failure Reduction; Customers	784
8		DARE OBERLIN/BENMARK LCP 327 1/2 A	866	1	Project	Overloaded Equipment Upgrades	OBERLIN	Overload Failure Reduction; Customers	183
9		DARE 15 MILE ROAD/15 MILE ROAD 605 1	608	1	Project	Overloaded Equipment Upgrades	MARENGO	Overload Failure Reduction; Customers	174
10		DARE COTTAGE GROVE/PREVO LCP871 LOC1-15	628	1	Project	Overloaded Equipment Upgrades	GARFIELD	Overload Failure Reduction; Customers	379
11		DARE KAWKAWLIN/LAGOON BEACH LCP 422	43	1	Project	Overloaded Equipment Upgrades	KAWKAWLIN	Overload Failure Reduction; Customers	927
12		DARE FRANKENMUTH/GERA LCP 942	22	1	Project	Overloaded Equipment Upgrades	FRANKENMUTH	Overload Failure Reduction; Customers	30
13		DARE HENDERSHOT_CENTENNIAL LCP 585	9	1	Project	Overloaded Equipment Upgrades	ADRIAN	Overload Failure Reduction; Customers	431
14		DARE CHEBOYGAN/ALVERNO LCP 761	177	1	Project	Overloaded Equipment Upgrades	CHEBOYGAN	Overload Failure Reduction; Customers	251
15		DARE COGGINS_ALMEDA LCP 780	39	1	Project	Overloaded Equipment Upgrades	PINCONNING	Overload Failure Reduction; Customers	103
16		DARE COWAN LAKE/RAMSDELL OVERLOADED FUSE	60	1	Project	Overloaded Equipment Upgrades	ROCKFORD	Overload Failure Reduction; Customers	131
17		DARE BULLOCK/STEWART LCP 918	16	1	Project	Overloaded Equipment Upgrades	MOUNT HALEY	Overload Failure Reduction; Customers	122
18		DARE CHAPIN/MARION LCP 141	30	1	Project	Overloaded Equipment Upgrades	MARION	Overload Failure Reduction; Customers	620
19		DARE FRANKENMUTH/DEHMEL LCP 422 ESIC OHL	5	1	Project	Overloaded Equipment Upgrades	FRANKENMUTH	Overload Failure Reduction; Customers	639
20		DARE CANNONSBURG/WEST CANNON LCP-840-1	278	1	Project	Overloaded Equipment Upgrades	BELMONT	Overload Failure Reduction; Customers	114
21		DARE EIGHT PT WHT BIRCH LCP 531	666	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	633
22		DARE HARRISON HARRISON LCP 381	17	1	Project	Overloaded Equipment Upgrades	HARRISON	Overload Failure Reduction; Customers	589
23		DARE NAPOLEON/WOLF LK-CADY RD PT. 1	655	1	Project	Overloaded Equipment Upgrades	NAPOLEON	Overload Failure Reduction; Customers	340
24		DARE TAMARACK-AMBLE CONV PHASE 3 OHL PT1	1,017	1	Project	Overloaded Equipment Upgrades	TAMARACK	Overload Failure Reduction; Customers	94
25		DARE JONESVILLE_JONESVILLE	9	1	Project	Overloaded Equipment Upgrades	JONESVILLE	Overload Failure Reduction; Customers	115
26		DARE BALCOM-BANKERS-LCP 795 ESIC OHL 1	496	1	Project	Overloaded Equipment Upgrades	READING	Overload Failure Reduction; Customers	87
27		DARE CEDAR SPRINGS-EDGERTON LCP 555	128	1	Project	Overloaded Equipment Upgrades	CEDAR SPRINGS	Overload Failure Reduction; Customers	121
28		DARE PORTSMOUTH/BLUMFIELD #255 LOC 1-21	751	1	Project	Overloaded Equipment Upgrades	SAGINAW	Overload Failure Reduction; Customers	386
29		DARE EIGHT POINT WHITE BIRCH LCP 830 1	430	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	317
30		DARE PARMA BALDWIN	103	1	Project	Overloaded Equipment Upgrades	PARMA	Overload Failure Reduction; Customers	1356
31		DARE PORTSMOUTH/INDIANTOWN PART 1	672	1	Project	Overloaded Equipment Upgrades	MUNGER	Overload Failure Reduction; Customers	315
32		DARE NOBLE_WHITNEY LCP 513	62	1	Project	Overloaded Equipment Upgrades	WHITNEY	Overload Failure Reduction; Customers	419
33		DARE PARAMOUNT/BIRD OVERLOADED CONDUCT	201	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	728
34		DARE RYNO_MORENCI LCP 358	33	1	Project	Overloaded Equipment Upgrades	MIO	Overload Failure Reduction; Customers	456
35		DARE OLIVET COLLEGE 415	31	1	Project	Overloaded Equipment Upgrades	OLIVET	Overload Failure Reduction; Customers	500
36		DARE N MUSKEGON STATE PARK LCP 076	205	1	Project	Overloaded Equipment Upgrades	NORTH MUSKEGON	Overload Failure Reduction; Customers	842
37		DARE PLAINWELL_HEIGHTS LCP 852	120	1	Project	Overloaded Equipment Upgrades	PLAINWELL	Overload Failure Reduction; Customers	1131
38		DARE PARAMOUNT/NORTHLAND FARMSLCP744 PT1	296	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	143
39		DARE PARAMOUNT/NORTHLAND FARMS PT 1	387	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	90
40		DARE BRIDGEPORT/DIXIE LCP 664	76	1	Project	Overloaded Equipment Upgrades	BRIDGEPORT	Overload Failure Reduction; Customers	59
41		DARE GERRISH-GOLF CLUB LCP 956 PT 1	394	1	Project	Overloaded Equipment Upgrades	BEAVER CREEK	Overload Failure Reduction; Customers	225
42		DARE CASINO_LEATON LCP 625	14	1	Project	Overloaded Equipment Upgrades	CHIPPEWA	Overload Failure Reduction; Customers	69
43		DARE ITHACA_FAIR GROUNDS LCP 463	28	1	Project	Overloaded Equipment Upgrades	ARCADA	Overload Failure Reduction; Customers	45
44		DARE MIDDLETON_NEWARK LCP 826	234	1	Project	Overloaded Equipment Upgrades	MIDDLETON	Overload Failure Reduction; Customers	82
45		DARE TAMARACK-LAKEVIEW PHASE 2.2 SEC 1	953	1	Project	Overloaded Equipment Upgrades	TAMARACK	Overload Failure Reduction; Customers	538
46		DARE MANNSIDING CEDAR LCP 231	7	1	Project	Overloaded Equipment Upgrades	LAKE GEORGE	Overload Failure Reduction; Customers	287
47		DARE KALAMO HWY ADD PHASE	563	1	Project	Overloaded Equipment Upgrades	CHARLOTTE	Overload Failure Reduction; Customers	319
48		DARE COLON_PALMER LCP 722	27	1	Project	Overloaded Equipment Upgrades	COLON	Overload Failure Reduction; Customers	318
49		DARE CAMDEN_MONTGOMERY LCP 283	29	1	Project	Overloaded Equipment Upgrades	CAMDEN	Overload Failure Reduction; Customers	105
50		DARE GRANT MASON DRIVE - LCP 235 - PT1	629	1	Project	Overloaded Equipment Upgrades	ASHLAND	Overload Failure Reduction; Customers	186
51		DARE MIDDLETON/MIDDLETON LCP945 ESICOHL	265	1	Project	Overloaded Equipment Upgrades	MIDDLETON	Overload Failure Reduction; Customers	50
52		DARE STONEY CORNERS-DAIRY LCP 343 1-9	441	1	Project	Overloaded Equipment Upgrades	RICHLAND	Overload Failure Reduction; Customers	60
53		DARE BUTTERFIELD LINDEN LCP 723	326	1	Project	Overloaded Equipment Upgrades	BROOKS	Overload Failure Reduction; Customers	132
54		DARE RANGER LAKE_KOKOSING LCP 591	7	1	Project	Overloaded Equipment Upgrades	HALE	Overload Failure Reduction; Customers	241
55		**LVD Lines Capacity Subtotal**	**14,563**						

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	Capacity								
1	LVD Lines Capacity	DARE RODNEY-RODNEY LCP 923	8	1	Project	Overloaded Equipment Upgrades	MECOSTA	Overload Failure Reduction; Customers	57
2		DARE OBERLIN PRATT LAKE LCP 398	228	1	Project	Overloaded Equipment Upgrades	GLADWIN	Overload Failure Reduction; Customers	329
3		DARE OBERLIN PRATT LAKE LCP 408A	474	1	Project	Overloaded Equipment Upgrades	GLADWIN	Overload Failure Reduction; Customers	614
4		DARE ROCKFORD_SUMMIT LCP-686	6	1	Project	Overloaded Equipment Upgrades	ROCKFORD	Overload Failure Reduction; Customers	99
5		DARE STARKS HOMER LCP 643	15	1	Project	Overloaded Equipment Upgrades	HOMER	Overload Failure Reduction; Customers	65
6		DARE MANNSIDING CEDAR LCP 377	51	1	Project	Overloaded Equipment Upgrades	LINCOLN	Overload Failure Reduction; Customers	145
7		DARE DIVISION_PIEDMONT LCP 117	129	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	353
8		DARE SARANAC_SARANAC LCP 740	45	1	Project	Overloaded Equipment Upgrades	BOSTON	Overload Failure Reduction; Customers	135
9		DARE RATIGAN_GREELEY LCP 353 OHL	154	1	Project	Overloaded Equipment Upgrades	GRATTAN	Overload Failure Reduction; Customers	70
10		DARE GREGORY UNADILLA LCP 877	36	1	Project	Overloaded Equipment Upgrades	UNADILLA	Overload Failure Reduction; Customers	305
11		DARE SEIDEL_BROCKWAY LCP 387	22	1	Project	Overloaded Equipment Upgrades	SAGINAW	Overload Failure Reduction; Customers	592
12		DARE OTISVILLE_IRISH ROAD LCP 072	18	1	Project	Overloaded Equipment Upgrades	FOREST	Overload Failure Reduction; Customers	33
13		DARE MARKEY CARRICK LCP 731	233	1	Project	Overloaded Equipment Upgrades	ROSCOMMON	Overload Failure Reduction; Customers	220
14		DARE LYON MANOR TOWNHALL LCP 912	29	1	Project	Overloaded Equipment Upgrades	ROSCOMMON	Overload Failure Reduction; Customers	783
15		DARE HANNAH_HANNAH LCP 331	13	1	Project	Overloaded Equipment Upgrades	WEXFORD	Overload Failure Reduction; Customers	114
16		DARE HANNAH_HANNAH LCP 5270	5	1	Project	Overloaded Equipment Upgrades	WEXFORD	Overload Failure Reduction; Customers	187
17		DARE BURR OAK_DOUGLAS LCP 929	55	1	Project	Overloaded Equipment Upgrades	FAWN RIVER	Overload Failure Reduction; Customers	48
18		DARE KIPP M-36 LCP5315 167 I	9	1	Project	Overloaded Equipment Upgrades	DANSVILLE	Overload Failure Reduction; Customers	79
19		DARE FROST LONG LAKE LCP 293	43	1	Project	Overloaded Equipment Upgrades	HARRISON	Overload Failure Reduction; Customers	213
20		DARE JAMES SAVAGE_WASHINGTON LCP 578	5	1	Project	Overloaded Equipment Upgrades	MIDLAND	Overload Failure Reduction; Customers	65
21		DARE BLACK RIVER_FILLMORE LCP 264	49	1	Project	Overloaded Equipment Upgrades	ZEELAND	Overload Failure Reduction; Customers	21
22		DARE MIDDLETON MIDDLETON LCP0639	3	1	Project	Overloaded Equipment Upgrades	MIDDLETON	Overload Failure Reduction; Customers	89
23		DARE MIDDLETON MIDDLETON LCP0711	42	1	Project	Overloaded Equipment Upgrades	MIDDLETON	Overload Failure Reduction; Customers	80
24		DARE COCHRAN_KALAMO LCP 628	30	1	Project	Overloaded Equipment Upgrades	CARMEL	Overload Failure Reduction; Customers	105
25		DARE POTTERVILLE_M78 LCP 565	12	1	Project	Overloaded Equipment Upgrades	DIMONDALE	Overload Failure Reduction; Customers	81
26		DARE CLYDE ROAD_GLENN ROAD LCP338 ISO	19	1	Project	Overloaded Equipment Upgrades	IONIA	Overload Failure Reduction; Customers	130
27		DARE GODFREY_LOWELL LCP 451	180	1	Project	Overloaded Equipment Upgrades	VERGENNES	Overload Failure Reduction; Customers	58
28		DARE RANGER LAKE_LUPTON ESIC OHL PT 1	1,072	1	Project	Overloaded Equipment Upgrades	HALE	Overload Failure Reduction; Customers	577
29		DARE LAKE CITY_MOREY LCP 199	17	1	Project	Overloaded Equipment Upgrades	CALDWELL	Overload Failure Reduction; Customers	220
30		DARE NEWBURG_VERNON LCP 464	9	1	Project	Overloaded Equipment Upgrades	VERNON	Overload Failure Reduction; Customers	31
31		DARE RANGER LAKE_LUPTON LCP 428	17	1	Project	Overloaded Equipment Upgrades	HALE	Overload Failure Reduction; Customers	147
32		DARE FENNVILLE_COMMERCIAL LCP 403	52	1	Project	Overloaded Equipment Upgrades	CLYDE	Overload Failure Reduction; Customers	35
33		DARE ENSLEY_BAPTIST LAKE_LCP 775	34	1	Project	Overloaded Equipment Upgrades	ENSLEY	Overload Failure Reduction; Customers	413
34		DARE CONKLIN PARK_CROTON_LCP 914	8	1	Project	Overloaded Equipment Upgrades	CROTON	Overload Failure Reduction; Customers	61
35		DARE_BIG PRAIRIE_OXBOW_LCP 915	10	1	Project	Overloaded Equipment Upgrades	BIG PRAIRIE	Overload Failure Reduction; Customers	334
36		DARE OBERLIN_BENMARK LCP 589	10	1	Project	Overloaded Equipment Upgrades	GLADWIN	Overload Failure Reduction; Customers	119
37		DARE MCBAIN_LAKE CITY LCP 0761	4	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	45
38		DARE LYONS_COLLINS RURAL LCP 338	192	1	Project	Overloaded Equipment Upgrades	LYONS	Overload Failure Reduction; Customers	128
39		DARE ROSEBUSH_DELWIN LCP 773	35	1	Project	Overloaded Equipment Upgrades	ISABELLA	Overload Failure Reduction; Customers	85
40		DARECARY-LKCOLUMBIA-561	19	1	Project	Overloaded Equipment Upgrades	COLUMBIA	Overload Failure Reduction; Customers	135
41		DARE MOLINE/GREEN LAKE ASC RECON PT1	1,038	1	Project	Overloaded Equipment Upgrades	NORTH GREEN	Overload Failure Reduction; Customers	1508
42		DARE PETTIS ROAD_HONEY CREEK LCP 980	198	1	Project	Overloaded Equipment Upgrades	ADA	Overload Failure Reduction; Customers	318
43		DARE EIGHT POINT WHITE BRCH LCP 565 UG	10	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	165
44		DARE HESPERIA RURAL LCP 325 PART 2	1,249	1	Project	Overloaded Equipment Upgrades	HESPERIA	Overload Failure Reduction; Customers	126
45		DARE SILVER LAKE_TWIN LAKE LCP 5744	3	1	Project	Overloaded Equipment Upgrades	GARFIELD	Overload Failure Reduction; Customers	140
46		DARE KINGSLEY_WALTON LCP 013	10	1	Project	Overloaded Equipment Upgrades	KINGSLEY	Overload Failure Reduction; Customers	81
47		DARE NORTHPORT_LIGHTHOUSE LCP 6049	10	1	Project	Overloaded Equipment Upgrades	NORTHPORT POINT	Overload Failure Reduction; Customers	232
48		DARE BOYNE MTN_MOUNTAIN LODGE LCP SUB	4	1	Project	Overloaded Equipment Upgrades	BOYNE FALLS	Overload Failure Reduction; Customers	280
49		DARE ROSE CITY_COYOTES LCP 108 ESIC OHL	169	1	Project	Overloaded Equipment Upgrades	FOSTER	Overload Failure Reduction; Customers	575
50		DARE CHESTER_CARLISLE LCP SUB	304	1	Project	Overloaded Equipment Upgrades	KALAMO	Overload Failure Reduction; Customers	473
51		DARE CHESTER_MORRELL LCP 316	21	1	Project	Overloaded Equipment Upgrades	CHESTER	Overload Failure Reduction; Customers	256
52		DARE DURAND GAINES INST RECLO	52	1	Project	Overloaded Equipment Upgrades	VERNON	Overload Failure Reduction; Customers	583
53		DARE CHARLOTTE_WATER WORKS LCP 812	67	1	Project	Overloaded Equipment Upgrades	CARMEL	Overload Failure Reduction; Customers	421
54		DARE SIMMONS_DAM ROAD LCP 0117	21	1	Project	Overloaded Equipment Upgrades	WEST BRANCH	Overload Failure Reduction; Customers	28
55		DARE ELEVENTH STREET_STARR ROAD LCP 765	31	1	Project	Overloaded Equipment Upgrades	GUN PLAIN	Overload Failure Reduction; Customers	1
56		**LVD Lines Capacity Subtotal**	**6,579**						

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	Capacity								
1	LVD Lines Capacity	DARE FLETCHER_ODEN LCP 0016	13	1	Project	Overloaded Equipment Upgrades	PETOSKEY	Overload Failure Reduction; Customers	101
2		DARE DEWITT_EAST HERBISON LCP SUB	43	1	Project	Overloaded Equipment Upgrades	DEWITT	Overload Failure Reduction; Customers	6793
3		DARE COCHRAN_SNOW LCP 634	36	1	Project	Overloaded Equipment Upgrades	CHARLOTTE	Overload Failure Reduction; Customers	36
4		DARE KELLOGGSVILLE_HOME ACRES LCP 0026	56	1	Project	Overloaded Equipment Upgrades	KENTWOOD	Overload Failure Reduction; Customers	1
5		DARE BEERS_NICHOLS LCP 385	51	1	Project	Overloaded Equipment Upgrades	GAINES	Overload Failure Reduction; Customers	64
6		DARE BLUE STAR_GANGES LCP 893	35	1	Project	Overloaded Equipment Upgrades	GANGES	Overload Failure Reduction; Customers	86
7		DARE CASCO_BLUFF LCP 042	225	1	Project	Overloaded Equipment Upgrades	CASCO	Overload Failure Reduction; Customers	642
8		DARE EAST JACKSON_TROJAN LCP 577	18	1	Project	Overloaded Equipment Upgrades	LEONI	Overload Failure Reduction; Customers	185
9		DARE BILLWOOD_LANSING ROAD LCP 535	73	1	Project	Overloaded Equipment Upgrades	WINDSOR	Overload Failure Reduction; Customers	200
10		DARE JOHNSON_LINCOLN LCP 835	8	1	Project	Overloaded Equipment Upgrades	ROBINSON	Overload Failure Reduction; Customers	166
11		DARE MORRELL_MCCAIN LCP 362	53	1	Project	Overloaded Equipment Upgrades	JACKSON	Overload Failure Reduction; Customers	108
12		DARE CARSON CITY_BUTTERNUT LCP SUB	49	2	Project	Overloaded Equipment Upgrades	BLOOMER	Overload Failure Reduction; Customers	406
13		DARE CAMBRIDGE-IRISHHILLS	506	1	Project	Overloaded Equipment Upgrades	CAMBRIDGE	Overload Failure Reduction; Customers	73
14		DARE HANNAH_HANNAH LCP 338	24	1	Project	Overloaded Equipment Upgrades	WEXFORD	Overload Failure Reduction; Customers	295
15		DARE SCENIC LAKE_SCENIC LAKE LCP 750	12	1	Project	Overloaded Equipment Upgrades	SHAFTSBURG	Overload Failure Reduction; Customers	105
16		DARE PIGEON LAKE_PIGEON LCP 962	405	1	Project	Overloaded Equipment Upgrades	WEST OLIVE	Overload Failure Reduction; Customers	227
17		DARE TAMARACK-AMBLE CONV PHASE 2-PART5	355	1	Project	Overloaded Equipment Upgrades	LAKEVIEW	Overload Failure Reduction; Customers	474
18		DARE STONEGATE_REMCO LCP 361	3	1	Project	Overloaded Equipment Upgrades	GRANDVILLE	Overload Failure Reduction; Customers	8
19		DARE HULL ST_LIME LAKE LCP 930 ISOLATOR	12	1	Project	Overloaded Equipment Upgrades	ALGOMA	Overload Failure Reduction; Customers	56
20		DARE MAGNUS EAGL CRNR LCP 823 PH3 RDGN	103	1	Project	Overloaded Equipment Upgrades	CLARE	Overload Failure Reduction; Customers	45
21		DARE BULLOCK/STEWART LCP 452	7	1	Project	Overloaded Equipment Upgrades	MOUNT HALEY	Overload Failure Reduction; Customers	74
22		DARE MORLEY/HOLLAND LCP 712	8	1	Project	Overloaded Equipment Upgrades	BUENA VISTA	Overload Failure Reduction; Customers	20
23		DARE ST CHARLES/FERGUS LCP 387	34	1	Project	Overloaded Equipment Upgrades	ST CHARLES	Overload Failure Reduction; Customers	27
24		DARE ULMER/BURT ROAD LCP 429	9	1	Project	Overloaded Equipment Upgrades	BIRCH RUN	Overload Failure Reduction; Customers	59
25		DARE WATKINS CHRISTY 491	87	1	Project	Overloaded Equipment Upgrades	BATTLE CREEK	Overload Failure Reduction; Customers	80
26		DARE TEKONSHA-WAGNER-LCP 245	27	1	Project	Overloaded Equipment Upgrades	BURLINGTON	Overload Failure Reduction; Customers	240
27		DARE GREENWOOD_RAU RD LCP 837 PT 1	409	1	Project	Overloaded Equipment Upgrades	EDWARDS	Overload Failure Reduction; Customers	158
28		DARE RANGER LAKE_LUPTON LCP 522	14	1	Project	Overloaded Equipment Upgrades	DELTA	Overload Failure Reduction; Customers	284
29		DARE SARANAC_SARANAC LCP 882	202	1	Project	Overloaded Equipment Upgrades	BOSTON	Overload Failure Reduction; Customers	149
30		DARE BRISTOL_MILLER LCP SUB	80	1	Project	Overloaded Equipment Upgrades	SAGINAW	Overload Failure Reduction; Customers	1020
31		DARE WITHEY LAKE_PETTIT LCP 0523	44	1	Project	Overloaded Equipment Upgrades	HILL	Overload Failure Reduction; Customers	415
32		DARE OBERLIN_BENMARK LCP 845	32	1	Project	Overloaded Equipment Upgrades	BUTMAN	Overload Failure Reduction; Customers	128
33		DARE UPTON_SIMMONS LCP 769	12	1	Project	Overloaded Equipment Upgrades	DELTA	Overload Failure Reduction; Customers	426
34		DARE SILVER LAKE SILVER PINES LCP 446 UG	239	1	Project	Overloaded Equipment Upgrades	GARFIELD	Overload Failure Reduction; Customers	481
35		DARE RANGER LAKE_GOODAR LCP 185 PART 1	2,482	1	Project	Overloaded Equipment Upgrades	GOODAR	Overload Failure Reduction; Customers	731
36		DARE BRADFORD_DISTRIBUTION LCP 588	26	1	Project	Overloaded Equipment Upgrades	PORTER	Overload Failure Reduction; Customers	349
37		DARE STARKS_HOMER LCP 429, LOCS 1-20	634	1	Project	Overloaded Equipment Upgrades	HOMER	Overload Failure Reduction; Customers	342
38		DARE THORNTON_WEST RIVER RD LCP 201	11	1	Project	Overloaded Equipment Upgrades	JEROME	Overload Failure Reduction; Customers	700
39		DARE VAN BUREN_VAN BUREN LCP 0029	17	1	Project	Overloaded Equipment Upgrades	GEORGETOWN	Overload Failure Reduction; Customers	851
40		DARE HANNAH_HANNAH LCP 337 PART 1	395	1	Project	Overloaded Equipment Upgrades	WEXFORD	Overload Failure Reduction; Customers	292
41		DARE FENNVILLE/COMMERCIAL PHASE 1	100	1	Project	Overloaded Equipment Upgrades	CLYDE	Overload Failure Reduction; Customers	784
42		DARE VANDERCOOK LK _ HAGUE RD LCP 770 OH	63	1	Project	Overloaded Equipment Upgrades	JACKSON	Overload Failure Reduction; Customers	1
43		DARE MUSKADAY TRL - ECNC RSO	2	1	Project	Overloaded Equipment Upgrades	WEXFORD	Overload Failure Reduction; Customers	1
44		DARE GRASS_LAKE 25 LCP 311 OH	35	1	Project	Overloaded Equipment Upgrades	GRASS LAKE	Overload Failure Reduction; Customers	80
45		DARE NAPOLEON/WOLF LK-NAPOLEON RD-PT.2	165	1	Project	Overloaded Equipment Upgrades	NAPOLEON	Overload Failure Reduction; Customers	109
46		DARE WAMPLERS_FRANKLIN RCD TW LCP 462J	1,046	1	Project	Overloaded Equipment Upgrades	FRANKLIN	Overload Failure Reduction; Customers	833
47		DARE CASCO_BLUFF LCP 282	1,347	1	Project	Overloaded Equipment Upgrades	CASCO	Overload Failure Reduction; Customers	1236
48		DARE GREENBUSH_GREENBUSH LLRP PH1 SHT1	4,013	1	Project	Overloaded Equipment Upgrades	HARRISVILLE	Overload Failure Reduction; Customers	1848
49		DARE BIRCH RUN/SAGINAW ROAD LCP 515	95	1	Project	Overloaded Equipment Upgrades	BIRCH RUN	Overload Failure Reduction; Customers	274
50		DARE BLUE STAR/PIER COVE LCP 619	618	1	Project	Overloaded Equipment Upgrades	GANGES	Overload Failure Reduction; Customers	131
51		DARE NAPOLEON/WOLF LK-NAPOLEON RD	830	1	Project	Overloaded Equipment Upgrades	NAPOLEON	Overload Failure Reduction; Customers	109
52		DARE ALLENDALE_BLENDON LCP 071 1	473	1	Project	Overloaded Equipment Upgrades	ALLENDALE	Overload Failure Reduction; Customers	169
53		DARE CHESTER_MORRELL LCP 315 - LOC 1-20	2,297	1	Project	Overloaded Equipment Upgrades	CHESTER	Overload Failure Reduction; Customers	256
54		DARE DEAN ROAD_HARTLAND LCP 812	8	1	Project	Overloaded Equipment Upgrades	TYRONE	Overload Failure Reduction; Customers	144
55		DARE DEAN ROAD_SHANNON LAKE LCP 156	11	1	Project	Overloaded Equipment Upgrades	ARGENTINE	Overload Failure Reduction; Customers	184
56	LVD Lines Capacity	DARE PEACH RIDGE/BALLARD PT1	766	1	Project	Sub Capacity-associated Line Work	SPARTA	Overload Failure Reduction; Customers	380
57		**LVD Lines Capacity Subtotal**	**18,719**						
58		**LVD Lines Capacity Total**	**39,861**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type
	Capacity							
1	LVD New Business Capacity	3RD ST ERET	1	1	Project	New Business Capacity Request	LAKETON	Increase capacity to meet customer demand
2		CANTERBURY LANE, FLT - ECNC UPU	3	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
3		ROWE CT MID ECNC CLO	1	1	Project	New Business Capacity Request	MIDLAND	Increase capacity to meet customer demand
4		FRONT AVE - CLU	7	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
5		E M 21, CUNA - ECNC UPU	3	1	Project	New Business Capacity Request	CALEDONIA	Increase capacity to meet customer demand
6		W SAINT CHARLES RD, ECNC CLO REHAB	3	1	Project	New Business Capacity Request	ARCADA	Increase capacity to meet customer demand
7		S HOOVER AVE, GLWN ECNC CLO	1	1	Project	New Business Capacity Request	ARTHUR	Increase capacity to meet customer demand
8		CRESCENT BEACH RD CLO	4	1	Project	New Business Capacity Request	ONEKAMA	Increase capacity to meet customer demand
9		S 4TH ST ECNC CLO - SOLAR EXPORT	3	1	Project	New Business Capacity Request	TEXAS	Increase capacity to meet customer demand
10		N RIPPLE CREEK RD - HSP - CLO	1	1	Project	New Business Capacity Request	DENVER	Increase capacity to meet customer demand
11		S US HIGHWAY 31 WLB ECNC CLO	4	1	Project	New Business Capacity Request	ELK RAPIDS	Increase capacity to meet customer demand
12		HUBBARD LAKE RD, HBDL, ECNC CLO	2	1	Project	New Business Capacity Request	CALEDONIA	Increase capacity to meet customer demand
13		W SHANNON RD B-2 MERL ECNC CLO	1	1	Project	New Business Capacity Request	JONESFIELD	Increase capacity to meet customer demand
14		LAKESHORE DR, CLDW - ECNC CLO	3	1	Project	New Business Capacity Request	ALGANSEE	Increase capacity to meet customer demand
15		Heath Rd Hastings ECNC CLO	1	1	Project	New Business Capacity Request	RUTLAND	Increase capacity to meet customer demand
16		E CODY ESTEY RD PNCG ECNC CLO	4	1	Project	New Business Capacity Request	PINCONNING	Increase capacity to meet customer demand
17		N WESTNEDGE AVE ECNC CLO	1	1	Project	New Business Capacity Request	COOPER	Increase capacity to meet customer demand
18		N Marshall Rd CLO	2	1	Project	New Business Capacity Request	HOMESTEAD	Increase capacity to meet customer demand
19		M37 BLDG 7 KGLY CLU	2	1	Project	New Business Capacity Request	MAYFIELD	Increase capacity to meet customer demand
20		L DR S Leroy ECNC CLO	4	1	Project	New Business Capacity Request	LEROY	Increase capacity to meet customer demand
21		NEWBERRY ST, ALGR, ECNC CLO	5	1	Project	New Business Capacity Request	MOFFATT	Increase capacity to meet customer demand
22		INDUSTRIAL DR,GYLG,ECNC CLO 3 c nts	111	1	Project	New Business Capacity Request	GRAYLING	Increase capacity to meet customer demand
23		E M 21, CUNA - ECNC CLO	7	1	Project	New Business Capacity Request	CALEDONIA	Increase capacity to meet customer demand
24		S SAGINAW RD, MID ECNC CLO	8	1	Project	New Business Capacity Request	MIDLAND	Increase capacity to meet customer demand
25		S FRANKLIN ST. SAG ECNC CLU	6	1	Project	New Business Capacity Request	SAGINAW	Increase capacity to meet customer demand
26		W CAYUGA, BLAR - CLO	1	1	Project	New Business Capacity Request	KEARNEY	Increase capacity to meet customer demand
27		MARSH RD PLNWL ECNC UPU	3	1	Project	New Business Capacity Request	GUN PLAIN	Increase capacity to meet customer demand
28		INDUSTRIAL DR,GYLG,ECNC CLO 1 c nts	239	1	Project	New Business Capacity Request	GRAYLING	Increase capacity to meet customer demand
29		E MOUNT GARFIELD RD UPU	2	1	Project	New Business Capacity Request	FRUITPORT	Increase capacity to meet customer demand
30		THORNTON AVE, FLT - ECNC UPU	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
31		MAST RD CLDW, ECNC CLO	3	1	Project	New Business Capacity Request	OVID	Increase capacity to meet customer demand
32		KENTUCKY AVE, CLARKLAKE - ECNC CLO	3	1	Project	New Business Capacity Request	COLUMBIA	Increase capacity to meet customer demand
33		E MICHIGAN AVE-GYLG-ECNC CLU	3	1	Project	New Business Capacity Request	GRAYLING	Increase capacity to meet customer demand
34		W GLENMERE RD EMP - ECNC UPU *NO TR	2	1	Project	New Business Capacity Request	EMPIRE	Increase capacity to meet customer demand
35		MILLER RD FLT-ECNC CLO	5	1	Project	New Business Capacity Request	BURTON	Increase capacity to meet customer demand
36		HARRIS RD CSNG ECNC UPO	1	1	Project	New Business Capacity Request	CHESANING	Increase capacity to meet customer demand
37		M37 BLDG 4 TO KGLY ECNC CLU	2	1	Project	New Business Capacity Request	MAYFIELD	Increase capacity to meet customer demand
38		N HARRISON AVE UNIT B, ECNC CLO	2	1	Project	New Business Capacity Request	HAYES	Increase capacity to meet customer demand
39		E ROUND LAKE RD, #2, DEW - CLO	3	1	Project	New Business Capacity Request	VICTOR	Increase capacity to meet customer demand
40		COUNTY RD 380, GJCT, ECNC CLO	1	1	Project	New Business Capacity Request	COLUMBIA	Increase capacity to meet customer demand
41		LAPLAISANCE RD - MNRO - ECNC CLO	4	1	Project	New Business Capacity Request	MONROE	Increase capacity to meet customer demand
42		RAY RD GNS ECNC CLO	1	1	Project	New Business Capacity Request	ARGENTINE	Increase capacity to meet customer demand
43		WESTSIDE SAGINAW RD BCY ECNC UPO	1	1	Project	New Business Capacity Request	MONITOR	Increase capacity to meet customer demand
44		KEYSTONE RD, WTMR, ECNC CLO	3	1	Project	New Business Capacity Request	BURLEIGH	Increase capacity to meet customer demand
45		N DAGGET RD, SAND LAKE- 1PH CLO TIE-s	21	1	Project	New Business Capacity Request	PIERSON	Increase capacity to meet customer demand
46		W CARD RD CLO	1	1	Project	New Business Capacity Request	READING	Increase capacity to meet customer demand
47		S FRANKLIN ST. SAG ECNC CLO	4	1	Project	New Business Capacity Request	SAGINAW	Increase capacity to meet customer demand
48		HATCHERY RD, FRWL REHAB CLO	1	1	Project	New Business Capacity Request	SURREY	Increase capacity to meet customer demand
49		S MAIN ST CRCO - ECNC CLO	10	1	Project	New Business Capacity Request	MARSHALL	Increase capacity to meet customer demand
50		S MAIN ST CRCO - ECNC UPU	2	1	Project	New Business Capacity Request	MARSHALL	Increase capacity to meet customer demand

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type
	Capacity							
1	LVD New Business Capacity	MOSSWOOD AVE CLU TRF *PC.OUT*	3	1	Project	New Business Capacity Request	PLAINFIELD	Increase capacity to meet customer demand
2		S 4TH ST KZO ECNC UPO	1	1	Project	New Business Capacity Request	TEXAS	Increase capacity to meet customer demand
3		INDUSTRIAL DR,GYLG,ECNC CLO 2 c nts	213	1	Project	New Business Capacity Request	GRAYLING	Increase capacity to meet customer demand
4		E YODER DR, MID ECNC UPO	1	1	Project	New Business Capacity Request	INGERSOLL	Increase capacity to meet customer demand
5		E CHICAGO RD CLO	3	1	Project	New Business Capacity Request	MOSCOW	Increase capacity to meet customer demand
6		MARSH RD PLNWL ECNC CLO	1	1	Project	New Business Capacity Request	GUN PLAIN	Increase capacity to meet customer demand
7		BENNETT, PERRINTON-OH CAPACITY	38	1	Project	New Business Capacity Request	NEW HAVEN	Increase capacity to meet customer demand
8		BENNETT, Perrinton-upgrade ugsv	2	1	Project	New Business Capacity Request	NEW HAVEN	Increase capacity to meet customer demand
9		E YODER DR, MID ECNC CLO	3	1	Project	New Business Capacity Request	INGERSOLL	Increase capacity to meet customer demand
10		S 4 3/4 MILE RD MIDLAND	1	1	Project	New Business Capacity Request	HOMER	Increase capacity to meet customer demand
11		DUGGAN DR LPTN CLO	8	1	Project	New Business Capacity Request	GOODAR	Increase capacity to meet customer demand
12		HARBOR ST OSDA CLO	3	1	Project	New Business Capacity Request	AU SABLE	Increase capacity to meet customer demand
13		E MICHIGAN AVE, JX ECNC CLO	15	1	Project	New Business Capacity Request	BLACKMAN	Increase capacity to meet customer demand
14		TROTWOOD LN, FLT - ECNC CLO	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
15		LAMBERTON ST NE-ECNC CLO	1	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
16		ROBERTS DR FLT ECNC CLO	4	1	Project	New Business Capacity Request	GENESEE	Increase capacity to meet customer demand
17		WHITE PINE 221 KZO ECNC CLU	2	1	Project	New Business Capacity Request	OSHTEMO	Increase capacity to meet customer demand
18		PINE ST CLO	7	1	Project	New Business Capacity Request	SHELBY	Increase capacity to meet customer demand
19		W GLENMERE RD EMP - ECNC CLO	1	1	Project	New Business Capacity Request	EMPIRE	Increase capacity to meet customer demand
20		JACKSON ST - ECNC CLO	3	1	Project	New Business Capacity Request	JAMESTOWN	Increase capacity to meet customer demand
21		BELLCLAIRE AVE SE - ECNC CLO	2	1	Project	New Business Capacity Request	GRAND RAPIDS	Increase capacity to meet customer demand
22		E FINERTY RD WBR CLO	2	1	Project	New Business Capacity Request	CHURCHILL	Increase capacity to meet customer demand
23		47TH ST, HAM, ECNC UPU	1	1	Project	New Business Capacity Request	OVERISEL	Increase capacity to meet customer demand
24		DARE CONVIS CONVIS LCP 369	4	1	Project	New Business Capacity Request	CONVIS	Increase capacity to meet customer demand
25		DOWNING HWY BRITTON ECNC CLO	9	1	Project	New Business Capacity Request	RIDGEWAY	Increase capacity to meet customer demand
26		MEADOWBROOK DR - UG COST ESTIMATE	20	1	Project	New Business Capacity Request	HUDSON	Increase capacity to meet customer demand
27		N AVERILL AVE- BLDG 5 - ECNC/UPU	1	1	Project	New Business Capacity Request	GENESEE	Increase capacity to meet customer demand
28		N AVERILL AVE- BLDG 6 - ECNC/UPU	1	1	Project	New Business Capacity Request	GENESEE	Increase capacity to meet customer demand
29		MCCONLEY COVE, PRTG - ECNC Rehab	7	1	Project	New Business Capacity Request	PORTAGE	Increase capacity to meet customer demand
30		LTOE Saginaw ST Building D	25	1	Project	New Business Capacity Request	BURTON	Increase capacity to meet customer demand
31		DEVELOPMENT - NBUS CLO	56	1	Project	New Business Capacity Request	CASCADE	Increase capacity to meet customer demand
32		DENNISON SUB VOLTAGE CONVERSION SECT 11B	7	1	Project	New Business Capacity Request	POLKTON	Increase capacity to meet customer demand
33		TWO MILE RD, UPGRADE UG ELEC LINE	3	1	Project	New Business Capacity Request	MONITOR	Increase capacity to meet customer demand
34		N MARBLE RD - ECNC UPU	3	1	Project	New Business Capacity Request	KEENE	Increase capacity to meet customer demand
35		N MARBLE RD - ECNC CLO 1 - 3	29	1	Project	New Business Capacity Request	KEENE	Increase capacity to meet customer demand
36		N MARBLE RD - ECNC CLO 71 - 94	118	1	Project	New Business Capacity Request	KEENE	Increase capacity to meet customer demand
37		N MARBLE RD - ECNC CLO 4 - 24	119	1	Project	New Business Capacity Request	KEENE	Increase capacity to meet customer demand
38		N MARBLE RD - ECNC CLO 51 - 70	133	1	Project	New Business Capacity Request	KEENE	Increase capacity to meet customer demand
39		N MARBLE RD - ECNC CLO 25 - 50	141	1	Project	New Business Capacity Request	KEENE	Increase capacity to meet customer demand
40		Recreation Dr - ECNC CLU	54	1	Project	New Business Capacity Request	BERLIN	Increase capacity to meet customer demand
41		Recreation Dr - ECNC CLO (3)	112	1	Project	New Business Capacity Request	BERLIN	Increase capacity to meet customer demand
42		Recreation Dr - ECNC CLO (2)	188	1	Project	New Business Capacity Request	BERLIN	Increase capacity to meet customer demand
43		Recreation Dr - Upgrade	235	1	Project	New Business Capacity Request	BERLIN	Increase capacity to meet customer demand
44		MT GARFIELD RD CLU	35	1	Project	New Business Capacity Request	NORTON	Increase capacity to meet customer demand
45		COURT ST, SAG; SVLT ECNC UPO	1	1	Project	New Business Capacity Request	SAGINAW	Increase capacity to meet customer demand
46		ECNC CLO - NUNICA_03 SECT 10 UGL	2	1	Project	New Business Capacity Request	CROCKERY	Increase capacity to meet customer demand
47		ECNC CLO - NUNICA_03 SECT 10	13	1	Project	New Business Capacity Request	CROCKERY	Increase capacity to meet customer demand
48		Milarch Rd, ONKM UPU	1	1	Project	New Business Capacity Request	ONEKAMA	Increase capacity to meet customer demand
49		Milarch Rd, ONKM CLO	44	1	Project	New Business Capacity Request	ONEKAMA	Increase capacity to meet customer demand
50		E 3RD ST EKRP ECNC CLU	16	1	Project	New Business Capacity Request	ELK RAPIDS	Increase capacity to meet customer demand

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	Capacity							
1	LVD New Business Capacity	N DAGGET RD SAND LAKE ECNC CLO	59	1	Project	New Business Capacity Request	PIERSON	Increase capacity to meet customer demand
2		OLTHOFF DR CLU	552	1	Project	New Business Capacity Request	MUSKEGON	Increase capacity to meet customer demand
3		E LANSING RD, HSLT ECNC CLO	1	1	Project	New Business Capacity Request	WOODHULL	Increase capacity to meet customer demand
4		CONDOS PHASE 3 CLO BILLABLE	16	1	Project	New Business Capacity Request	GRAND	Increase capacity to meet customer demand
5		LAWNDALE AVE, KZOO, PRIMARY METERED	22	1	Project	New Business Capacity Request	COMSTOCK	Increase capacity to meet customer demand
6		S JEROME RD, PRTN, ECNC CLO	120	1	Project	New Business Capacity Request	FULTON	Increase capacity to meet customer demand
7		NEW HOLLAND ST CLO *CK ON REGS	114	1	Project	New Business Capacity Request	PARK	Increase capacity to meet customer demand
8		E CARPENTER RD BARN FLT ECNC UPO	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
9		E MICHIGAN AVE-GYLG-ECNO UPU	3	1	Project	New Business Capacity Request	GRAYLING	Increase capacity to meet customer demand
10		5TH AVE MTE - ECNC UPO	1	1	Project	New Business Capacity Request	FILER	Increase capacity to meet customer demand
11		5TH AVE MTE - ECNC CLO	4	1	Project	New Business Capacity Request	FILER	Increase capacity to meet customer demand
12		S CRAPO RD, ICA, ECNC UPU	2	1	Project	New Business Capacity Request	NORTH STAR	Increase capacity to meet customer demand
13		S CRAPO RD, ICA, ECNC CLO	5	1	Project	New Business Capacity Request	NORTH STAR	Increase capacity to meet customer demand
14		ESTATES PHASE 3 - ECNC CLU	125	1	Project	New Business Capacity Request	PAVILION	Increase capacity to meet customer demand
15		SENATOR RD BARN FENWICK ECNC CLO	4	1	Project	New Business Capacity Request	BLOOMER	Increase capacity to meet customer demand
16		W HEMPHILL RD, FLT - ECNC UPO	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
17		ESTATES PHASE 1 - ECNC CLU	84	1	Project	New Business Capacity Request	PAVILION	Increase capacity to meet customer demand
18		ESTATES PHASE 2 - ECNC CLU	100	1	Project	New Business Capacity Request	PAVILION	Increase capacity to meet customer demand
19		104TH AVE, ALGN - ECNC CLO	68	1	Project	New Business Capacity Request	CHESHIRE	Increase capacity to meet customer demand
20		FISHER RD HWL ECNC CLO	1	1	Project	New Business Capacity Request	DEERFIELD	Increase capacity to meet customer demand
21		S FRANKLIN ST. SAG ECNC UPU	1	1	Project	New Business Capacity Request	SAGINAW	Increase capacity to meet customer demand
22		BELLEVUE RD ECNC UPO	1	1	Project	New Business Capacity Request	PENNFIELD	Increase capacity to meet customer demand
23		BELLEVUE RD ECNC CLO	3	1	Project	New Business Capacity Request	PENNFIELD	Increase capacity to meet customer demand
24		LINCOLN AVE, FLT - ECNC UPU	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
25		LINCOLN AVE, FLT - ECNC CLO	2	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
26		PENINSULA DR TC ECNC CLU *HYDAKER B	4	1	Project	New Business Capacity Request	ACME	Increase capacity to meet customer demand
27		N LAKE ST LLND- ECNC UPU *BORE WMC D	2	1	Project	New Business Capacity Request	LELAND	Increase capacity to meet customer demand
28		N LAKE ST LLND- ECNC CLU	3	1	Project	New Business Capacity Request	LELAND	Increase capacity to meet customer demand
29		M 60 LEONIDAS ECNC CLO	3	1	Project	New Business Capacity Request	LEONIDAS	Increase capacity to meet customer demand
30		VISTA DR PULL POLE PP	1	1	Project	New Business Capacity Request	BROOKS	Increase capacity to meet customer demand
31		MOSCOW RD-HANOVER_HORTON-ECNC UPO	1	1	Project	New Business Capacity Request	HANOVER	Increase capacity to meet customer demand
32		S WISE RD ecnc clo	4	1	Project	New Business Capacity Request	COE	Increase capacity to meet customer demand
33		JASMINE ST GYLD - CLO *PC.OUT 2.4 B/	2	1	Project	New Business Capacity Request	BAGLEY	Increase capacity to meet customer demand
34		JASMINE ST GYLD - CLU *WMC BORE BY 2	4	1	Project	New Business Capacity Request	BAGLEY	Increase capacity to meet customer demand
35		JACKSON ST - ECNC UPO	1	1	Project	New Business Capacity Request	JAMESTOWN	Increase capacity to meet customer demand
36		N MERIDIAN RD ecnc clo	3	1	Project	New Business Capacity Request	ISABELLA	Increase capacity to meet customer demand
37		E HOWE RD, DEW - CLO	5	1	Project	New Business Capacity Request	DEWITT	Increase capacity to meet customer demand
38		S US 31 HWY GARAGE ALSN - UPO	1	1	Project	New Business Capacity Request	LITTLEFIELD	Increase capacity to meet customer demand
39		S US 31 HWY GARAGE ALSN - CLO	1	1	Project	New Business Capacity Request	LITTLEFIELD	Increase capacity to meet customer demand
40		Sandy Beach St Wayland ECNC CLO	2	1	Project	New Business Capacity Request	YANKEE SPRINGS	Increase capacity to meet customer demand
41		TYRRELL RD LGBG ECNC CLO	1	1	Project	New Business Capacity Request	SCIOTA	Increase capacity to meet customer demand
42		Hall St--UPGD OH TRF (DELTA to WYE)	24	1	Project	New Business Capacity Request	ADA	Increase capacity to meet customer demand
43		112TH AVE, FENNVILLE-RECON OHLN	6	1	Project	New Business Capacity Request	CLYDE	Increase capacity to meet customer demand
44		CENTRE INDUSTRIAL DR SW- NSU (3PH)	1	1	Project	New Business Capacity Request	BYRON	Increase capacity to meet customer demand
45		CENTRE INDUSTRIAL DR SW- NLO	4	1	Project	New Business Capacity Request	BYRON	Increase capacity to meet customer demand
46		3 MILE RD NW - ECNC UPU	3	1	Project	New Business Capacity Request	WALKER	Increase capacity to meet customer demand
47		COCHRAN RD, HRTN ECNC CLO	1	1	Project	New Business Capacity Request	HANOVER	Increase capacity to meet customer demand
48		N 3 RD, MSK- ECNC UPO	1	1	Project	New Business Capacity Request	SPRINGVILLE	Increase capacity to meet customer demand
49		S SHAYTOWN RD VMTV - ECNC CLO	1	1	Project	New Business Capacity Request	KALAMO	Increase capacity to meet customer demand
50		LAKE AVE RPID ECNC CLO *NJUNS*	4	1	Project	New Business Capacity Request	HELENA	Increase capacity to meet customer demand

MICHIGAN PUBLIC SERVICE COMMISSION
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Bridge Period LVD Project List
For the Bridge Period 16 Months Ending April 30, 2027
($000)

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type
	Capacity							
1	LVD New Business Capacity	145TH AVE, HOL, EC	1	1	Project	New Business Capacity Request	LAKETOWN	Increase capacity to meet customer demand
2		S CHERRY ST, HOL, ECNC UPU	1	1	Project	New Business Capacity Request	LAKETOWN	Increase capacity to meet customer demand
3		COLLEGE AVE SE - UPO	1	1	Project	New Business Capacity Request	PARIS	Increase capacity to meet customer demand
4		W CHIPPEWA RIVER RD ECNC CLO REHAB	2	1	Project	New Business Capacity Request	LEE	Increase capacity to meet customer demand
5		DIXON RD, JX, ECNC CLU	5	1	Project	New Business Capacity Request	TOMPKINS	Increase capacity to meet customer demand
6		N MERIDIAN RD #B, ELSIE - UPG 500KV	5	1	Project	New Business Capacity Request	FAIRFIELD	Increase capacity to meet customer demand
7		BURTON ST SE - CLU	12	1	Project	New Business Capacity Request	PARIS	Increase capacity to meet customer demand
8		LAKE DR SE - ECNC CLO	2	1	Project	New Business Capacity Request	PARIS	Increase capacity to meet customer demand
9		E BRITTON RD MRCE ECNC UPU	1	1	Project	New Business Capacity Request	ANTRIM	Increase capacity to meet customer demand
10		E BRITTON RD MRCE ECNC CLO	5	1	Project	New Business Capacity Request	ANTRIM	Increase capacity to meet customer demand
11		MAIN ST ELSW CLO	3	1	Project	New Business Capacity Request	BANKS	Increase capacity to meet customer demand
12		BERRYNOLL CT, CLDW, ECNC CLO	3	1	Project	New Business Capacity Request	OVID	Increase capacity to meet customer demand
13		GOLDEN AVE, BCK - ECNC CLO	5	1	Project	New Business Capacity Request	EMMETT	Increase capacity to meet customer demand
14		COLDWATER RD, FLSH ECNC CLO	5	1	Project	New Business Capacity Request	FLUSHING	Increase capacity to meet customer demand
15		GRAND RIVER AVE CLKVE - ECNC CLO	1	1	Project	New Business Capacity Request	BOSTON	Increase capacity to meet customer demand
16		S CASTOR RD SHEPHERD ECNC CLO	2	1	Project	New Business Capacity Request	LEE	Increase capacity to meet customer demand
17		68TH ST, SHVN EC	1	1	Project	New Business Capacity Request	CASCO	Increase capacity to meet customer demand
18		68TH ST, SHVN EC #2	2	1	Project	New Business Capacity Request	CASCO	Increase capacity to meet customer demand
19		W ADRIAN ST-BSFL-ECNC CLU-LNS UG	15	1	Project	New Business Capacity Request	BLISSFIELD	Increase capacity to meet customer demand
20		DEAL PKWY, JNSVL - ECNC CLU	5	1	Project	New Business Capacity Request	HILLSDALE	Increase capacity to meet customer demand
21		FERN ST HALE CLO	3	1	Project	New Business Capacity Request	PLAINFIELD	Increase capacity to meet customer demand
22		KLENDER RD BTLY ECNC CLO	5	1	Project	New Business Capacity Request	GRIM	Increase capacity to meet customer demand
23		CHICAGO DR, ZLND ECNC CLO	3	1	Project	New Business Capacity Request	ZEELAND	Increase capacity to meet customer demand
24		RAMBLIN DR BCK ECNC CLO	4	1	Project	New Business Capacity Request	PENNFIELD	Increase capacity to meet customer demand
25		I 94, GRASS LAKE - ECNC CLO	3	1	Project	New Business Capacity Request	GRASS	Increase capacity to meet customer demand
26		CEDAR ST CAD ECNC CLO *PC.OUT 2.11 B	13	1	Project	New Business Capacity Request	CLAM LAKE	Increase capacity to meet customer demand
27		CASH DR, JX ECNC CLO	5	1	Project	New Business Capacity Request	LEONI	Increase capacity to meet customer demand
28		BURLINGTON RD ECNC CLO	1	1	Project	New Business Capacity Request	UNION	Increase capacity to meet customer demand
29		CAUSEWAY DR NE - ECNC CLO	1	1	Project	New Business Capacity Request	GRATTAN	Increase capacity to meet customer demand
30		S LK HURON SHORE DR, HRSV, ECNC UPO	1	1	Project	New Business Capacity Request	HARRISVILLE	Increase capacity to meet customer demand
31		SOUTHGATE DR, FNT - ECNC CLO	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
32		S Jones Dr, ECNC, CLO	4	1	Project	New Business Capacity Request	JOHNSTOWN	Increase capacity to meet customer demand
33		Washington St BDWN ECNC UPU	1	1	Project	New Business Capacity Request	PLEASANT PLAIN	Increase capacity to meet customer demand
34		N DYE RD, FLT ECNC CLO	1	1	Project	New Business Capacity Request	FLINT	Increase capacity to meet customer demand
35		KEYES RD, ECNC, CLO	1	1	Project	New Business Capacity Request	ASSYRIA	Increase capacity to meet customer demand
36		INDIAN RD KDN ECNC CLO	1	1	Project	New Business Capacity Request	ELK RAPIDS	Increase capacity to meet customer demand
37		112TH AVE, LEE TWP-REHAB OHLN	4	1	Project	New Business Capacity Request	CLYDE	Increase capacity to meet customer demand
38		BROCKWAY ST SAG ECNC CLO	2	1	Project	New Business Capacity Request	SAGINAW	Increase capacity to meet customer demand
39		W WILMAS WAY BDWN ECNC CLO	2	1	Project	New Business Capacity Request	WEBBER	Increase capacity to meet customer demand
40		O AVE ,MTWN, ECNC CLO	1	1	Project	New Business Capacity Request	TEXAS	Increase capacity to meet customer demand

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Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	Conservation Voltage Reduction	CVR_BOWEN_KIMBERLY	1	1	Circuit	Conservation Voltage Reduction	CITY OF GRAND RAPIDS	kW Energy Savings	7
2		CVR_STANDALE_STANDALE	2	1	Circuit	Conservation Voltage Reduction	CITY OF WALKER	kW Energy Savings	27
3		CVR_MANCHESTER_AUSTIN ROAD	80	1	Circuit	Conservation Voltage Reduction	CITY OF MANCHESTER	kW Energy Savings	10
4		CVR_MILLERS POINT_ARCADIA	60	1	Circuit	Conservation Voltage Reduction	CITY OF KALAMAZOO	kW Energy Savings	41
5		CVR_OAK STREET_WEST GANSON	32	1	Circuit	Conservation Voltage Reduction	CITY OF JACKSON	kW Energy Savings	49
6		CVR_BOSTON SQUARE_HALL	2	1	Circuit	Conservation Voltage Reduction	CITY OF GRAND RAPIDS	kW Energy Savings	15
7		CVR_RAMONA_BLODGETT	84	1	Circuit	Conservation Voltage Reduction	CITY OF EAST GRAND RAPIDS	kW Energy Savings	57
8		CVR_COOLEY_NORTH STREET	2	1	Circuit	Conservation Voltage Reduction	CITY OF KALAMAZOO	kW Energy Savings	15
9		CVR_MICHIGAN CENTER_BALLARD	25	1	Circuit	Conservation Voltage Reduction	LEONI TOWNSHIP	kW Energy Savings	15
10		CVR_GIRARD_GIRARD	10	1	Circuit	Conservation Voltage Reduction	GIRARD TWP	kW Energy Savings	15
11		CVR_BYRON CENTER_BYRON CENTER	69	1	Circuit	Conservation Voltage Reduction	BYRON TWP	kW Energy Savings	41
12		CVR_LAKE ODESSA_INDUSTRIAL	1	1	Circuit	Conservation Voltage Reduction	ODESSA TWP	kW Energy Savings	91
13		CVR_PARKWAY_VINE	60	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	96
14		CVR_DOEHLER JARVIS_GRIGGS STREET	112	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	54
15		CVR_GOODALE_ROOSEVELT	50	1	Circuit	Conservation Voltage Reduction	BEDFORD TWP	kW Energy Savings	48
16		CVR_GOGUAC_LAKEVIEW	2	1	Circuit	Conservation Voltage Reduction	BATTLE CREEK TWP	kW Energy Savings	158
17		CVR_BEECHER_TOLEDO ROAD	50	1	Circuit	Conservation Voltage Reduction	MADISON TWP	kW Energy Savings	72
18		CVR_MT PLEASANT_COLLEGE	50	1	Circuit	Conservation Voltage Reduction	UNION TWP	kW Energy Savings	155
19		CVR_SCHOOL ROAD_MOROCCO	35	1	Circuit	Conservation Voltage Reduction	BEDFORD TWP	kW Energy Savings	122
20		CVR_TALLMAN_WACOUSTA	25	1	Circuit	Conservation Voltage Reduction	EAGLE TWP	kW Energy Savings	136
21		CVR_PHILLIPS_FACTORY	25	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	76
22		CVR_VAN ATTA_POWELL	25	1	Circuit	Conservation Voltage Reduction	MERIDIAN TWP	kW Energy Savings	138
23		CVR_TECUMSEH_EVANS STREET	25	1	Circuit	Conservation Voltage Reduction	TECUMSEH TWP	kW Energy Savings	170
24		CVR_POTTERVILLE_POTTERVILLE	25	1	Circuit	Conservation Voltage Reduction	BENTON TWP	kW Energy Savings	82
25		CVR_TRAVIS_COLLINGWOOD	25	1	Circuit	Conservation Voltage Reduction	COOPER TWP	kW Energy Savings	117
26		CVR_HYDE PARK_DUCK LAKE	50	1	Circuit	Conservation Voltage Reduction	DALTON TWP	kW Energy Savings	151
27		CVR_HYDE PARK_DUCK LAKE	25	1	Circuit	Conservation Voltage Reduction	HAMPTON TWP	kW Energy Savings	70
28		CVR_EASTWOOD_TEXEL	75	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	98
29		CVR_WASHINGTON_FIRST STREET	35	1	Circuit	Conservation Voltage Reduction	PERE MARQUETTE TWP	kW Energy Savings	26
30		CVR_HOLLY_ACADEMY	75	1	Circuit	Conservation Voltage Reduction	HOLLY TWP	kW Energy Savings	49
31		CVR_PHILLIPS_INKSTER	78	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	117
32		CVR_BOSTON SQUARE_MULICK PARK	100	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	98
33		CVR_IVANREST_LACROSSE	50	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	47
34		CVR_RED ARROW_OGEMA	30	1	Circuit	Conservation Voltage Reduction	BURTON TWP	kW Energy Savings	82
35		CVR_RED ARROW_MARKHAM	25	1	Circuit	Conservation Voltage Reduction	BURTON TWP	kW Energy Savings	111
36		CVR_NAPOLEON_MOON LAKE	48	1	Circuit	Conservation Voltage Reduction	NAPOLEON TWP	kW Energy Savings	128
37		CVR_ROSE CITY_KLACKING CREEK	100	1	Circuit	Conservation Voltage Reduction	CUMMING TWP	kW Energy Savings	95
38		CVR_WHITTUM_PETRIEVILLE	50	1	Circuit	Conservation Voltage Reduction	EATON RAPIDS TWP	kW Energy Savings	24
39		CVR_SHATTUCK_COUNTY FARM	75	1	Circuit	Conservation Voltage Reduction	SAGINAW	kW Energy Savings	88
40		CVR_GROVER_TRIANGLE	75	1	Circuit	Conservation Voltage Reduction	ARCADA TWP	kW Energy Savings	58
41		CVR_DALE ROAD_M-18	75	1	Circuit	Conservation Voltage Reduction	BEAVERTON TWP	kW Energy Savings	62
42		CVR_GRANT_CATALPA	75	1	Circuit	Conservation Voltage Reduction	ASHLAND TWP	kW Energy Savings	25
43		CVR_CEDAR SPRING_NELSON	100	1	Circuit	Conservation Voltage Reduction	CEDAR SPRING	kW Energy Savings	122
44		CVR_OLIVET_AINGER	100	1	Circuit	Conservation Voltage Reduction	WALTON TWP	kW Energy Savings	15
45		CVR_CHAUNCY_CASS	50	1	Circuit	Conservation Voltage Reduction	ALBION	kW Energy Savings	39
46		CVR_PATTERSON_PATTERSON	50	1	Circuit	Conservation Voltage Reduction	BAY CITY	kW Energy Savings	63
47		CVR_DUCK LAKE_DUCK LAKE	50	1	Circuit	Conservation Voltage Reduction	CLARENCE TWP	kW Energy Savings	24
48		CVR_EAST GENESEE AVE_BAGLEY	50	1	Circuit	Conservation Voltage Reduction	SAGINAW	kW Energy Savings	34
49		CVR_FREMONT_HIGH SCHOOL	100	1	Circuit	Conservation Voltage Reduction	FREMONT	kW Energy Savings	84
50		CVR_KNIGHT_HAMPTON	100	1	Circuit	Conservation Voltage Reduction	HAMPTON TWP	kW Energy Savings	55
51		CVR_LELAND_LELAND	100	1	Circuit	Conservation Voltage Reduction	LELAND TWP	kW Energy Savings	52
52		CVR_LOMBARD_LOMBARD	50	1	Circuit	Conservation Voltage Reduction	ALBION TWP	kW Energy Savings	67
53		CVR_MCMILLAN_RIVER	100	1	Circuit	Conservation Voltage Reduction	DALTON TWP	kW Energy Savings	62
54		CVR_MORRICE_SOUTH MORRICE	100	1	Circuit	Conservation Voltage Reduction	MORRICE	kW Energy Savings	40
55		CVR_NIAGARA_HAMILTON	100	1	Circuit	Conservation Voltage Reduction	SAGINAW	kW Energy Savings	32
56		CVR_OVID_OVID	100	1	Circuit	Conservation Voltage Reduction	OVID	kW Energy Savings	52
57		CVR_RAVINE_RAVINE	100	1	Circuit	Conservation Voltage Reduction	KALAMAZOO	kW Energy Savings	64
58		CVR_SALEM_BURNIPS	50	1	Circuit	Conservation Voltage Reduction	SALEM TWP	kW Energy Savings	31
59		CVR_WIRTZ ROAD_WILDWOOD	100	1	Circuit	Conservation Voltage Reduction	SECORD TWP	kW Energy Savings	38
60		CVR_HILL ROAD_WALKABOUT	50	1	Circuit	Conservation Voltage Reduction	MUNDY TWP	kW Energy Savings	27
61		Identified CVR Voltage Remediation Upgrades	500			Conservation Voltage Reduction	MICHIGAN	kW Energy Savings	-
62		**CVR Total**	**3,868**						

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Test Year LVD Project List

For the Test Year 12 Months Ending April 30, 2028

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Asset Relocations								
		Associated HVD Lines Project:							
1	LVD Asset Relocations	Cooper 22A (STR432 - STR518)	215	4.7	Miles	LVD Underbuild	Merrill	Obligation to serve	138,180
2		Morrice (028E STR 36 - Springbrook)	200	4.5	Miles	LVD Underbuild	Shiawassee	Obligation to serve	148,554
3		Shelby (White Lake - Rothbury)	235	5.3	Miles	LVD Underbuild	Oceana	Obligation to serve	48,845
4		Casino (spur to Weidman)	375	8.5	Miles	LVD Underbuild	Isabella	Obligation to serve	293,792
5		Remus - South Portion	350	8.0	Miles	LVD Underbuild	Mecosta	Obligation to serve	93,352
6		Niagara (034A)	40	0.7	Miles	LVD Underbuild	Saginaw	Obligation to serve	9,524
7		Goodale - 80C	15	0.2	Miles	LVD Underbuild	Calhoun	Obligation to serve	9,575
8		Port Sheldon (relocate STR 96 - STR 105)	35	0.5	Miles	LVD Underbuild	Ottawa	Obligation to serve	3
9		Broadway 37E (STR 71 - STR 59)	35	0.6	Miles	LVD Underbuild	Muskegon	Obligation to serve	6,509
10		LN030A ROBERTS 46KVRBLD TO ROYAL SUB *13	7	0.1	Miles	LVD Underbuild	Jackson	Obligation to serve	428
11		LN030F PARNALL 46KVRBLD TO ROYAL SUB *13	7	0.1	Miles	LVD Underbuild	Jackson	Obligation to serve	710
12		LN030C WESTWD 46KVRBLD TO ROYAL SUB *13	7	0.1	Miles	LVD Underbuild	Jackson	Obligation to serve	1,767
13		LN030E OAK ST 46KV RBLD TO ROYAL SUB *13	32	0.4	Miles	LVD Underbuild	Jackson	Obligation to serve	8,387
14		LN021E PARMA 46KV RBLD TO ROYAL SUB *13	67	1.3	Miles	LVD Underbuild	Jackson	Obligation to serve	64,915
15		LN026D STOCKBR 46KVRBLD TO ROYAL SUB *13	72	1.4	Miles	LVD Underbuild	Jackson	Obligation to serve	33,590
16		LN021C LESLIE 46KV RBLD TO ROYAL SUB *13	26	0.4	Miles	LVD Underbuild	Jackson	Obligation to serve	9,000
17		LN030I PARNALL 46KVRBLD TO ROYAL SUB *13	7	0.1	Miles	LVD Underbuild	Jackson	Obligation to serve	2,813
18		LN069A HANOVER 46KVRBLD TO ROYALSUB% *13	7	0.1	Miles	LVD Underbuild	Jackson	Obligation to serve	1,806
19		LN069W WESTWD 46KVRBLD TO ROYAL SUB% *13	7	0.1	Miles	LVD Underbuild	Jackson	Obligation to serve	2,270
20		Newaygo 19D river crossing	15	0.3	Miles	LVD Underbuild	Newaygo	Obligation to serve	5,830
21		Saranac 111A (STR 272-243)	125	2.3	Miles	LVD Underbuild	Ionia	Obligation to serve	27,531
22		Pole Replacements	3,388	1050	Poles	Pole Replacements	Various locations statewide	Obligation to serve	757,575
23		Switch Replacements	2,000	90	Switches	Switch Replacements	Various locations statewide	Obligation to serve	20,475
24		**LVD Asset Relocations Total (LVD Underbuild Only)**	**7,267**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	Backus springbrook delta conversion	1,900	6.00	Miles	Voltage Conversion	BACKUS	Customer-outage-minutes avoided	963,300
2		RLBY Riverbend/Hale Rd Volt Conv Part 1	435	2.80	Miles	Voltage Conversion	OMER	Customer-outage-minutes avoided	220,545
3		RLBY Riverbend/Hale Rd Volt Conv Part 2	450	3.40	Miles	Voltage Conversion	OMER	Customer-outage-minutes avoided	-
4		RLBY Riverbend/Hale Rd Volt Conv Part 3	540	3.20	Miles	Voltage Conversion	OMER	Customer-outage-minutes avoided	-
5		RLBY Grayling_Bear LCP 087	270	2.71	Miles	Voltage Conversion	GRAYLING	Customer-outage-minutes avoided	136,890
6		RLBY Turner/Gates LCP 450B Volt Conv	400	5.20	Miles	Voltage Conversion	TURNER	Customer-outage-minutes avoided	152,100
7		RLBY Turner/Grove Volt Conv	60	0.40	Miles	Voltage Conversion	TURNER	Customer-outage-minutes avoided	30,420
8		RLBY Au Gres/Point Lookout Volt Conv	15	0.40	Miles	Voltage Conversion	SIMS	Customer-outage-minutes avoided	7,605
9		RLBY Gilson_Wyman LCP 458 Volt Conv	273	14.16	Miles	Voltage Conversion	EDMORE	Customer-outage-minutes avoided	138,352
10		RLBY Gilson_Wyman LCP 608 Volt Conv	1,195	11.44	Miles	Voltage Conversion	EDMORE	Customer-outage-minutes avoided	605,924
11		RLBY Gilson_Wyman LCP 557 Volt Conv	70	0.66	Miles	Voltage Conversion	EDMORE	Customer-outage-minutes avoided	35,669
12		RLBY Gilson_Wyman LCP 592 Volt Conv	281	2.58	Miles	Voltage Conversion	EDMORE	Customer-outage-minutes avoided	142,355
13		RLBY Gilson_Rock Lake LCP 801 Volt Conv Part 1	592	6.79	Miles	Voltage Conversion	EDMORE	Customer-outage-minutes avoided	300,243
14		RLBY Gilson_Rock Lake LCP 801 Volt Conv Part 2	968	9.02	Miles	Voltage Conversion	EDMORE	Customer-outage-minutes avoided	490,850
15		RLBY Gilson_Rock Lake LCP 804 Volt Conv	27	0.11	Miles	Voltage Conversion	EDMORE	Customer-outage-minutes avoided	13,852
16		RLBY Withey Lake/Pettit LCP 003 Volt Conv	727	5.44	Miles	Voltage Conversion	CHURCHILL	Customer-outage-minutes avoided	368,681
17		RLBY Withey Lake/Pettit LCP 006 Volt Conv	236	4.58	Miles	Voltage Conversion	CHURCHILL	Customer-outage-minutes avoided	119,438
18		RLBY Withey Lake/Pettit LCP 706 Volt Conv	673	5.52	Miles	Voltage Conversion	CHURCHILL	Customer-outage-minutes avoided	341,390
19		RLBY RIVERDALE/RIVERDALE LCP 028 volt conv	2,748	21.91	Miles	Voltage Conversion	SUMNER	Customer-outage-minutes avoided	1,393,337
20		RLBY RIVERDALE/RIVERDALE LCP 043 volt conv	792	6.51	Miles	Voltage Conversion	SUMNER	Customer-outage-minutes avoided	401,412
21		RLBY HOWARD CITY/MORLEY LCP 433 volt conv	1,453	8.59	Miles	Voltage Conversion	REYNOLDS	Customer-outage-minutes avoided	736,877
22		RLBY INDIAN RIVER/RONDO LCP 712 volt conv part 1	685	7.89	Miles	Voltage Conversion	TUSCARORA	Customer-outage-minutes avoided	347,453
23		RLBY INDIAN RIVER/RONDO LCP 712 volt conv part 2	310	5.70	Miles	Voltage Conversion	TUSCARORA	Customer-outage-minutes avoided	157,218
24		RLBY INDIAN RIVER/RONDO LCP 712 volt conv part 3	533	4.63	Miles	Voltage Conversion	TUSCARORA	Customer-outage-minutes avoided	270,149
25		RLBY INDIAN RIVER/RONDO LCP 564 east - volt conv	653	5.48	Miles	Voltage Conversion	TUSCARORA	Customer-outage-minutes avoided	331,144
26		RLBY INDIAN RIVER/RONDO LCP 798 - volt conv	1,446	7.08	Miles	Voltage Conversion	TUSCARORA	Customer-outage-minutes avoided	732,995
27		RLBY INDIAN RIVER/RONDO LCP 799 - volt conv	2,227	10.48	Miles	Voltage Conversion	TUSCARORA	Customer-outage-minutes avoided	1,128,994
28		RLBY POINT LUDINGTON LCP512 HZD	300	3.00	Miles	Voltage Conversion	LUDINGTON	Customer-outage-minutes avoided	6,376
29		RLBY Edmore/Six Lakes SUB part 1a volt conv	848	8.10	Miles	Voltage Conversion	EDMORE	Customer-outage-minutes avoided	33,703
30		RLBY Edmore/Six Lakes SUB part 1b volt conv	400	4.00	Miles	Voltage Conversion	EDMORE	Customer-outage-minutes avoided	33,700
31		RLBY Edmore/Six Lakes SUB part 2 volt conv	1,100	11.00	Miles	Voltage Conversion	EDMORE	Customer-outage-minutes avoided	101,109
32		DTOY BOYNE CITY_VETERANS LCP 677	758	4.80	Miles	Voltage Conversion	Charlevoix	Customer-outage-minutes avoided	16,848
33		DTOY MANISTEE_FILER CITY LCP 177	1,028	2.40	Miles	Voltage Conversion	Manistee	Customer-outage-minutes avoided	9,960
34		DTOY MANISTEE_MANISTEE SALT LCP 161	382	1.12	Miles	Voltage Conversion	Manistee	Customer-outage-minutes avoided	7,244
35		DTOY Channel Substation	1,730	10.17	Miles	Voltage Conversion	Manistee	Customer-outage-minutes avoided	42,800
36		DTOY HARRIETTA-CABERFAE	2,000	10.67	Miles	Voltage Conversion	Wexford	Customer-outage-minutes avoided	20,000
37		DTOY HARRIETTA-BOON	2,800	10.50	Miles	Voltage Conversion	Wexford	Customer-outage-minutes avoided	64,460
38		DTOY HARRIETTA-MARILLA	2,800	10.50	Miles	Voltage Conversion	Wexford	Customer-outage-minutes avoided	5,880
39		**LVD Lines Reliability Subtotal (Voltage Conversion Total)**	**34,106**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-168 (JMP-2)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	FREDERICK ST SAUG ECNC RSU	9	0.0	Miles	Zonal Health Improvements	ALLEGAN	Customer-outage-minutes avoided	2,105
2		C DR N OHS	2	0.0	Miles	Zonal Health Improvements	CALHOUN	Customer-outage-minutes avoided	12,168
3		JUDITH ANN DR - ECNC RSO	2	0.0	Miles	Zonal Health Improvements	GENESEE	Customer-outage-minutes avoided	980
4		CAMDEN_CAMDEN PHASE SWAPS	9	0.0	Miles	Zonal Health Improvements	HILLSDALE	Customer-outage-minutes avoided	1,000
5		RLBY GERRISH-6 4366 ARAUCO RD GRAYLING	11	0.0	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	2,029
6		VOLT Starks Lee LCP 848	10	0.1	Miles	Zonal Health Improvements	MIDLAND	Customer-outage-minutes avoided	563
7		RLBY GILSON_WYMAN LCP 654	19	0.0	Miles	Zonal Health Improvements	MONTCALM	Customer-outage-minutes avoided	143,333
8		SECT15 FENTON/ DENTON HILL & SILVER LAKE	11	0.1	Miles	Zonal Health Improvements	OAKLAND	Customer-outage-minutes avoided	7,959
9		RLBY MURNER_VAN TYLE MILLBOCKER ESIC	336	0.0	Miles	Zonal Health Improvements	OTSEGO	Customer-outage-minutes avoided	6,612
10		RLBY MURNER_VAN TYLE LCP SUB	15	0.0	Miles	Zonal Health Improvements	OTSEGO	Customer-outage-minutes avoided	560,278
11		RLBY VIRGINIA PARK_MACATAWA ATR LOOP	492	1.1	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	254,075
12		KENT CITY_CASNOV BALL CRK	528	0.7	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	726,472
13		RLBY KENT CITY_CASNOVIA LCP 228 P1_2	761	1.1	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	223,231
14		KENT CITY CASNOVIA 1520 S TRENT RD OHS	10	0.0	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	2,510
15		RLBY MACATAWA BEE LINE LCP 636	111	0.4	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	19,760
16		GRID HAGER PARK01_HAGER PARK02	63	0.0	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	2,040
17		GRID HAGER PARK02_CHICAGO02	139	4.0	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	1,524,100
18		RLBY PIGEON LAKE_PIGEON LCP CKT	550	0.8	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	316,278
19		RLBY PIGEON LAKE_PIGEON LCP 146	886	1.7	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	80,336
20		RLBY PIGEON LAKE - LAKESHORE DR	8	0.0	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	1,616
21		RLBY 88th Ave West Olive-OHL	14	0.0	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	280
22		RLBY SPRING LAKE/COUN CLUB LCP416	343	0.3	Miles	Zonal Health Improvements	OTTAWA	Customer-outage-minutes avoided	44,795
23		RLBY BACKUS SPRINGBROOK LCP 872	528	1.1	Miles	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	34,604
24		RLBY HOUGHTON HTS-PVL LCP 945 *RC	117	0.5	Miles	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	2,027
25		RLBY MARKEY/FOREST ESTATES LCP452	592	2.5	Miles	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	10,796
26		VOLT MARKEY LYON MANOR TREASURE	12	0.1	Miles	Zonal Health Improvements	ROSCOMMON	Customer-outage-minutes avoided	2,412
27		FUSE ROSE CITY_KLACKING CREEK ALL	452	0.0	Miles	Zonal Health Improvements	ROSE CITY	Customer-outage-minutes avoided	8,104
28		RLBY INGERSOLL_SASSE LCP 005	343	1.9	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	104,830
29		RLBY BUSCH ROAD/CURTIS LCP 699	39	0.2	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	3,944
30		RLBY BUSCH ROAD/CURTIS LCP 736	97	0.4	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	18,112
31		RLBY ST CHARLES/SAGINAW BEAVER CREEK	261	0.5	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	22,285
32		RLBY BRIDGEPORT/BRIDGEPORT LCP 228	136	0.3	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	1,009
33		RLBY STATE STREET_STATE STREET	18	0.1	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	194,238
34		RLBY SHIELDS/SHIELDS LCP 325 PART 2	52	0.0	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	49,063
35		RLBY HACKETT_HACKETT RECONDUCTOR	167	0.5	Miles	Zonal Health Improvements	SAGINAW	Customer-outage-minutes avoided	81,812
36		RLBY MENDON PINHOOK LCP 645	354	0.5	Miles	Zonal Health Improvements	ST JOSEPH	Customer-outage-minutes avoided	15,394
37		RLBY HUBBARD LAKE_HUBBARD LAKE LCP SUB	946	2.0	Miles	Zonal Health Improvements	TAWAS	Customer-outage-minutes avoided	449,718
38		RLBY PORTSMOUTH/INDIANTOWN LCP 337 RELOC	54	0.2	Miles	Zonal Health Improvements	TUSCOLA	Customer-outage-minutes avoided	2,176
39		104th Ave ECNC RSU	8	0.0	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	1,000
40		RLBY BITTERSWEET RIVER RD	589	1.4	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	319,671
41		RLBY TEXAS_EAGLE LAKE LCP 746	354	0.5	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	179,478
42		RLBY ALAMO_PINE GROVE LCP 612 - 1_2	679	0.9	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	7,863
43		RLBY ALAMO_PINE GROVE - ESIC UGS	62	0.0	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	8,785
44		GRNT RLBY ALAMO_PINE GROVE LCP 638	1,302	2.2	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	412,900
45		RLBY SPICEBUSH_LESTER LAKE	261	0.8	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	34,534
46		RLBY OSHTEMO ALMENA LCP 576	62	0.0	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	172,172
47		RLBY LAWRENCE CHRISTIE LAKE LCP653 Pt1 2	1,032	1.1	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	117,803
48		RLBY LAWRENCE BRUSH CREEK 142	377	0.7	Miles	Zonal Health Improvements	VAN BUREN	Customer-outage-minutes avoided	70,687
49		RLBY ABBE_CALDWELL LCP 666	206	0.7	Miles	Zonal Health Improvements	WEST BRANCH	Customer-outage-minutes avoided	2,093
50		RLBY ABBE_ABBE LCP 0144	1,700	3.5	Miles	Zonal Health Improvements	WEST BRANCH	Customer-outage-minutes avoided	755,671
51		RLBY LK MIT-GLF CLB LCP 6001 3 2691 S	1,706	3.3	Miles	Zonal Health Improvements	WEXFORD	Customer-outage-minutes avoided	77,696
52		RLBY LINCOLN_MIKADO LCP 0957	1,522	3.1	Miles	Zonal Health Improvements	MIKADO	Customer-outage-minutes avoided	275,609
53		RLBY ABBE_ABBE LCP 0028	1,292	2.0	Miles	Zonal Health Improvements	COMINS	Customer-outage-minutes avoided	355,170
54		RLBY KENT CITY_CASNOVIA LCP 0703	993	0.6	Miles	Zonal Health Improvements	CASNOVIA	Customer-outage-minutes avoided	285,915
55		RLBY BUCHANAN SANDY SHORES LCP 778	879	1.6	Miles	Zonal Health Improvements	MACATAWA	Customer-outage-minutes avoided	368,845
56		RLBY HAGER PARK HAGER PARK LCP SUB	783	1.3	Miles	Zonal Health Improvements	GEORGETOWN	Customer-outage-minutes avoided	911,048
57		RLBY THORNTON_WEST RIVER RD LCP 0691	751	2.0	Miles	Zonal Health Improvements	JEROME	Customer-outage-minutes avoided	285,082
58		RLBY WARNER_MILO LCP 553	715	1.3	Miles	Zonal Health Improvements	DOSTER	Customer-outage-minutes avoided	304,022
59		RLBY BOSTON SQUARE_KALAMAZOO 1ST ZONE	642	0.4	Miles	Zonal Health Improvements	GRAND RAPIDS	Customer-outage-minutes avoided	7,533
60		RLBY KEATING_LAKETON LCP CKT	626	1.0	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	37,141
61		RLBY STANDALE_CHESTERFIELD LCP 560	624	0.7	Miles	Zonal Health Improvements	TALLMADGE	Customer-outage-minutes avoided	29,523
62		RLBY MCMILLAN_RIVER LCP 789	558	0.8	Miles	Zonal Health Improvements	DALTON	Customer-outage-minutes avoided	831,956
63		RLBY NORTH PARK_LAMBERTON CKT	539	0.7	Miles	Zonal Health Improvements	EAST GRAND RAPIDS	Customer-outage-minutes avoided	120,827
64		GRANT RLBY GLADWIN BUZL LCP663 HZD CND	512	1.8	Miles	Zonal Health Improvements	GLADWIN	Customer-outage-minutes avoided	41,224
65		RLBY Honor/Platte LCP 6899	452	2.1	Miles	Zonal Health Improvements	BENZONIA	Customer-outage-minutes avoided	41,224
66		RLBY EASTWOOD_TEXEL LCP CKT	385	0.5	Miles	Zonal Health Improvements	KALAMAZOO	Customer-outage-minutes avoided	126,824
67		RLBY Quincy/Blackhawk LCP 214	379	1.0	Miles	Zonal Health Improvements	ALGANSEE	Customer-outage-minutes avoided	12,686
68		HQAPPR SCDY ELM STREET_VERONA_4	376	1.0	Miles	Zonal Health Improvements	BATTLE CREEK	Customer-outage-minutes avoided	214,320
69		VOLT Dewitt-Howe Rd	362	1.0	Miles	Zonal Health Improvements	RILEY	Customer-outage-minutes avoided	152,040
70		HQAPPR SCDY ELM STREET_PORTER_Concept_3	360	1.0	Miles	Zonal Health Improvements	BATTLE CREEK	Customer-outage-minutes avoided	151,200
71		HQAPPR SCDY ELM STREET_VERONA_7	358	1.0	Miles	Zonal Health Improvements	BATTLE CREEK	Customer-outage-minutes avoided	110,601
72		HQAPPR SCDY ELM STREET VERONA 2	329	1.1	Miles	Zonal Health Improvements	BATTLE CREEK	Customer-outage-minutes avoided	87,531
73		RLBY LELAND LELAND LCP 240	318	0.4	Miles	Zonal Health Improvements	LELAND	Customer-outage-minutes avoided	41,998
74		SYSP DELTON DELTON	304	0.0	Miles	Zonal Health Improvements	BARRY	Customer-outage-minutes avoided	10,000
75		HZRD DONTZ RD-PORTAGE LCP 288	300	0.2	Miles	Zonal Health Improvements	ONEKAMA	Customer-outage-minutes avoided	9,492
76		RLBY Ft Custer_Harmonia LCP 311	275	0.9	Miles	Zonal Health Improvements	BATTLE CREEK	Customer-outage-minutes avoided	8,571
77		RLBY MONTAGUE_DOWLING LCP 211	273	0.0	Miles	Zonal Health Improvements	MONTAGUE	Customer-outage-minutes avoided	149,340
78		RLBY NORTH MUSKEGON_DALTON LCP 244	262	1.0	Miles	Zonal Health Improvements	LAKETON	Customer-outage-minutes avoided	348,580
79		RLBY HOSPITAL_ELMWOOD LCP 204	248	0.5	Miles	Zonal Health Improvements	ELMWOOD	Customer-outage-minutes avoided	104,160
80		RLBY LAKE ODESSA LAKE LCP 585	242	0.5	Miles	Zonal Health Improvements	ODESSA	Customer-outage-minutes avoided	100,871
81		RLBY WHITEHALL ALICE LCP 874	184	0.6	Miles	Zonal Health Improvements	MONTAGUE	Customer-outage-minutes avoided	235,875
82		SAFETY QUINCY_BLACKHAWK	109	0.3	Miles	Zonal Health Improvements	GIRARD	Customer-outage-minutes avoided	41,860
83		RLBY EIGHT POINT WHT BRCH LCP 706	102	0.3	Miles	Zonal Health Improvements	GARFIELD	Customer-outage-minutes avoided	57,120
84		APPRSCDY MAPLE GROVE_HENRY STREET PART E	91	0.4	Miles	Zonal Health Improvements	MUSKEGON	Customer-outage-minutes avoided	50,960
85		APPR MAPLE GROVE_HENRY STREET Part D	80	0.3	Miles	Zonal Health Improvements	ROOSEVELT PARK	Customer-outage-minutes avoided	802
86		RLBY PARMA_PARMA LCP 118	77	1.0	Miles	Zonal Health Improvements	PARMA	Customer-outage-minutes avoided	300,266
87		Volt HARVEY_FULLER TLM 0711321204	66	0.6	Miles	Zonal Health Improvements	GRAND RAPIDS	Customer-outage-minutes avoided	46,880
88		BKBNZ DONTZ ROAD/PORTAGE LCP 295	56	0.5	Miles	Zonal Health Improvements	MANISTEE	Customer-outage-minutes avoided	23,520
89		PENTWATER CARROLL LCP 276	1,631	2.4	Miles	Zonal Health Improvements	OCEANA	Customer-outage-minutes avoided	13,800
90		**LVD Lines Reliability Subtotal (Zonal Health Subtotal)**	**34,890**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-168 (JMP-2)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	EXIT NEW HAVEN JUDDVILLE	8	1	Project	Circuit Exit Projects	SHIAWASSEE	Increase Safety by Installing Isolation Point	-
2		EXIT LEHRING	8	1	Project	Circuit Exit Projects	SHIAWASSEE	Increase Safety by Installing Isolation Point	-
3		EXIT MIDDLETON_ALL CIRCUITS	176	1	Project	Circuit Exit Projects	GRATIOT	Increase Safety by Installing Isolation Point	-
4		EXIT20 PICKEREL-INDIAN LAKE-UNDERGROUND	29	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
5		EXIT ENGLISHVILLE_PINE ISLAND SUB EXIT	12	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
6		EXIT CLIMAX	83	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
7		EXIT EAST GRANT SUB EXIT SW	40	1	Project	Circuit Exit Projects	Muskegon	Increase Safety by Installing Isolation Point	-
8		EXIT HOSPITAL SUB EXIT SWITCHES	24	1	Project	Circuit Exit Projects	Traverse City	Increase Safety by Installing Isolation Point	-
9		EXIT INTERLOCHEN SUB EXIT SWITCHES	24	1	Project	Circuit Exit Projects	Traverse City	Increase Safety by Installing Isolation Point	-
10		EXIT LELAND SUB EXIT SWITCHES	24	1	Project	Circuit Exit Projects	Traverse City	Increase Safety by Installing Isolation Point	-
11		EXIT ANTRIM SUB	24	1	Project	Circuit Exit Projects	Traverse City	Increase Safety by Installing Isolation Point	-
12		EXIT LEELANAU SUB EXIT SWITCHES	13	1	Project	Circuit Exit Projects	Traverse City	Increase Safety by Installing Isolation Point	-
13		EXIT16 MAPLE GROVE HENRY STREET EXIT	108	1	Project	Circuit Exit Projects	Muskegon	Increase Safety by Installing Isolation Point	-
14		EXIT AGNEW SUB EXIT SW	38	1	Project	Circuit Exit Projects	Muskegon	Increase Safety by Installing Isolation Point	-
15		EXIT FERRIS STREET SUB EXIT SW	35	1	Project	Circuit Exit Projects	Muskegon	Increase Safety by Installing Isolation Point	-
16		EXIT HAGER PARK EXIT SWITCHES	16	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
17		EXIT CLAY SUB EXIT SWITCHES	24	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
18		EXIT JAMESTOWN-JAMESTOWN SWITCH	24	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
19		EXIT ROSEWOOD SUB SWITCHES	24	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
20		EXIT Big Rapids sub	11	1	Project	Circuit Exit Projects	MECOSTA	Increase Safety by Installing Isolation Point	-
21		EXIT 19 mile road sub	27	1	Project	Circuit Exit Projects	MECOSTA	Increase Safety by Installing Isolation Point	-
22		EXIT BOWEN/AIRCRAFT CKTS 12	18	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
23		EXIT - LEE STREET-CENTURY	20	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
24		EXIT MAYNARD	14	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
25		EXIT KELLOGGSVILLE/CHEMICAL CKTS 34	18	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
26		RLBY Marker Lake Sub Exit SW	8	1	Project	Circuit Exit Projects	IONIA	Increase Safety by Installing Isolation Point	-
27		RLBY Belding Sub Exit SW	7	1	Project	Circuit Exit Projects	IONIA	Increase Safety by Installing Isolation Point	-
28		RLBY Godfrey Sub Exit SW	7	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
29		RLBY Palo Sub Exit SW	7	1	Project	Circuit Exit Projects	IONIA	Increase Safety by Installing Isolation Point	-
30		RLBY Grand Valley Sub Exit SW	8	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
31		EXIT Mullins Sub Exit SW	66	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
32		EXIT Rivertown Sub Exit SW	88	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
33		RLBY Pettis Road Sub Exit SW	33	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
34		RLBY Ratigan Sub Exit SW	33	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
35		RLBY Alpine Sub Exit SW	48	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
36		RLBY Coit Avenue Sub Exit SW	48	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
37		RLBY Cowan Lake Sub Exit SW	33	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
38		RLBY Lamoreaux Sub Exit SW	33	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
39		EXIT North Park Sub Exit SW	22	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
40		RLBY Plainfield Sub Exit SW	48	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
41		EXIT LOMBARD	29	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
42		EXIT HOMER	15	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
43		EXIT READING	15	1	Project	Circuit Exit Projects	HILLSDALE	Increase Safety by Installing Isolation Point	-
44		EXIT MENDON	29	1	Project	Circuit Exit Projects	ST JOSEPH	Increase Safety by Installing Isolation Point	-
45		EXIT TEXAS	15	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
46		Exits Liberty	36	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
47		Exits Renton	44	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
48		EXIT Ottawa Beach Sub	74	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
49		EXITS WOODLAND	53	1	Project	Circuit Exit Projects	BARRY	Increase Safety by Installing Isolation Point	-
50		EXITS RUTLAND	40	1	Project	Circuit Exit Projects	BARRY	Increase Safety by Installing Isolation Point	-
51		EXIT OAKWOOD	15	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
52		**Circuit Exits Subtotal**	**1,694**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-168 (JMP-2)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliability	EXIT PARKWAY	8	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
2		EXIT PHILLIPS	17	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
3		EXIT OWOSSO	70	1	Project	Circuit Exit Projects	SHIAWASSEE	Increase Safety by Installing Isolation Point	-
4		EXIT ROUND LAKE	24	1	Project	Circuit Exit Projects	LENAWEE	Increase Safety by Installing Isolation Point	-
5		Wakeshma Sub Exits and LVD Work	121	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
6		EXIT MIDWAY	14	1	Project	Circuit Exit Projects	ALLEGAN	Increase Safety by Installing Isolation Point	-
7		EXIT MT FOREST_MT FOREST	9	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
8		THDPY EXIT ULMER/MARKET PLACE	29	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
9		EXIT EDDY/WADSWORTH	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
10		EXIT HOTCHKISS_OLD BRIDGE	22	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
11		EXIT MCGRAW_PORTSMOUTH	10	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
12		EXIT EDDY/FINDLEY	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
13		EXIT MCGRAW_CASS	10	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
14		EXIT FRANKENMUTH/INDUSTRIAL	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
15		EXIT FRANKENMUTH/MAIN STREET	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
16		EXIT FRANKENMUTH/DEHMEL	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
17		EXIT FRANKENMUTH/GERA	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
18		EXIT PORTSMOUTH/BLUMFIELD	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
19		EXIT FINDLEY/NODULAR	13	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
20		EXIT KNIGHT_HAMPTON	9	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
21		EXIT KNIGHT_FARLEY	9	1	Project	Circuit Exit Projects	BAY	Increase Safety by Installing Isolation Point	-
22		EXIT DAVENPORT_SCHAEFFER	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
23		EXIT NIAGARA/ADAMS	13	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
24		EXIT NIAGARA_HAMILTON	13	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
25		THDPY EXIT ULMER/BURT ROAD	13	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
26		EXIT WESTERVELT/TITTABAWASSEE	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
27		EXIT WESTERVELT/KOCHVILLE	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
28		EXIT THOMAS/FROST	10	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
29		EXIT DAVENPORT_CONGRESS	13	1	Project	Circuit Exit Projects	SAGINAW	Increase Safety by Installing Isolation Point	-
30		EXIT HARRISON_STOCKWELL	11	1	Project	Circuit Exit Projects	CLARE	Increase Safety by Installing Isolation Point	-
31		EXIT BELLEVUE	32	1	Project	Circuit Exit Projects	EATON	Increase Safety by Installing Isolation Point	-
32		RLBY - WILDER WILDER 15KV SUB EXIT	340	1	Project	Circuit Exit Projects	CALHOUN	Increase Safety by Installing Isolation Point	-
33		EXIT Wakeshma	9	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
34		EXIT SPRINGPORT	16	1	Project	Circuit Exit Projects	JACKSON	Increase Safety by Installing Isolation Point	-
35		EXIT PARNALL	16	1	Project	Circuit Exit Projects	JACKSON	Increase Safety by Installing Isolation Point	-
36		EXIT VANDERCOOK LAKE	24	1	Project	Circuit Exit Projects	JACKSON	Increase Safety by Installing Isolation Point	-
37		WISNER UG EXIT	20	1	Project	Circuit Exit Projects	JACKSON	Increase Safety by Installing Isolation Point	-
38		RLBY20 PULLMAN SUB EXIT SWITCH	100	1	Project	Circuit Exit Projects	ALLEGAN	Increase Safety by Installing Isolation Point	-
39		EXIT SWAN CREEK SUB	15	1	Project	Circuit Exit Projects	ALLEGAN	Increase Safety by Installing Isolation Point	-
40		EXIT ATWATER	25	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
41		EXIT AMPERSEE	25	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
42		EXIT VIRGINIA PARK_CASTLE LCP SUB	30	1	Project	Circuit Exit Projects	ALLEGAN	Increase Safety by Installing Isolation Point	-
43		EXIT BIL-MAR	46	1	Project	Circuit Exit Projects	OTTAWA	Increase Safety by Installing Isolation Point	-
44		RLBY Alto Sub Exit SW	7	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
45		RLBY Foreman Sub Exit SW	7	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
46		RLBY Meadowbrooke Sub Exit SW	22	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
47		RLBY Kraft Avenue Sub Exit SW	17	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
48		EXIT 0-AT-KA SUB EXIT SWITCHES	16	1	Project	Circuit Exit Projects	GRAND TRAVERSE	Increase Safety by Installing Isolation Point	-
49		EXITS BROGAN	19	1	Project	Circuit Exit Projects	BARRY	Increase Safety by Installing Isolation Point	-
50		EXIT UG VILLAGE GREEN CKT 4 EXIT A_B	134	1	Project	Circuit Exit Projects	KALAMAZOO	Increase Safety by Installing Isolation Point	-
51		EXIT Broadmoor Sub	37	1	Project	Circuit Exit Projects	KENT	Increase Safety by Installing Isolation Point	-
52		**Circuit Exit Subtotal**	**1,495**						
53		**LVD Lines Reliability Subtotal (Circuit Exit Total)**	**3,189**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Lines Reliability - LVD	SCDY DERBY_DERBY	382	0.69	Miles	Secondary	Greenville	Service Quality; Customers	278
2		SCDY EASTWOOD_TEXEL	1362	4.94	Miles	Secondary	Kalamazoo	Service Quality; Customers	911
3		SCDY ELEVENTH STREET_BASELINE	363	0.9	Miles	Secondary	Kalamazoo	Service Quality; Customers	62
4		SCDY ELM STREET_PORTER	496	1.97	Miles	Secondary	Battle Creek	Service Quality; Customers	327
5		SCDY ELM STREET_VERONA	25	0.12	Miles	Secondary	Battle Creek	Service Quality; Customers	12
6		SCDY FLUSHING_MARY STREET	258	0.95	Miles	Secondary	Flint	Service Quality; Customers	89
7		SCDY JUDD ROAD_MANDEVILLE	734	4.85	Miles	Secondary	Flint	Service Quality; Customers	573
8		SCDY KENDALL_WESTWOOD	1136	6.19	Miles	Secondary	Kalamazoo	Service Quality; Customers	938
9		SCDY LIBERTY_WASHINGTON	142	0.56	Miles	Secondary	Battle Creek	Service Quality; Customers	200
10		SCDY LOMBARD_SHERIDAN	776	3.62	Miles	Secondary	Battle Creek	Service Quality; Customers	342
11		SCDY MAPLE GROVE_HENRY STREET	576	2.81	Miles	Secondary	Muskegon	Service Quality; Customers	244
12		SCDY MAPLE GROVE_SHAW BOX	365	2.41	Miles	Secondary	Muskegon	Service Quality; Customers	195
13		SCDY MAPLE GROVE_SUMMIT AVENUE	1801	3.97	Miles	Secondary	Muskegon	Service Quality; Customers	420
14		SCDY MICHIGAN_LOOKOUT	359	1.05	Miles	Secondary	Grand Rapids	Service Quality; Customers	299
15		SCDY ORIOLE_WHITTIER	1258	3.53	Miles	Secondary	Ludington	Service Quality; Customers	361
16		SCDY OSHTEMO_HURD	81	0.15	Miles	Secondary	Kalamazoo	Service Quality; Customers	13
17		SCDY PHILLIPS_MILWOOD	1727	7.45	Miles	Secondary	Kalamazoo	Service Quality; Customers	1,179
18		SCDY SLOAN_LONGFELLOW	2730	11.23	Miles	Secondary	Flint	Service Quality; Customers	1,766
19		SCDY WILMOTT_WILMOTT	95	0.86	Miles	Secondary	Hamilton	Service Quality; Customers	33
20		**LVD Lines Reliability Subtotal (Secondary Total)**	**14,664**						
21	Lines Reliability - LVD	UINJ Cable Rejuvenation Grand Rapids	5,408	10	Miles	Underground Cable Injection	Grand Rapids Area	Customer-outage-minutes avoided	644,781
22		UINJ Cable Rejuvenation Traverse City	4,327	8	Miles	Underground Cable Injection	Traverse City Area	Customer-outage-minutes avoided	507,569
23		**LVD Lines Reliability Subtotal (Underground Cable Injection Total)**	**9,735**						
24	Lines Reliability - LVD	**Right of Way**	**11,373**	n/a	n/a	Right of Way			n/a
25	Lines Reliability - LVD	**Groundline Inspections - Pole Replacements**	**125,000**	12,500	Poles	Pole Replacements	Statewide	Customer-outage-minutes avoided	32359

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category/Strategy	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Reliabiity	DISTA CADMUS02_CADMUS01	397	1	Loop	Automation - ATR Loops	ADR	Customer-outage-minutes-avoided	51,120
2		DISTA OWOSSO06_CORUNNA06	245	1	Loop	Automation - ATR Loops	FLT	Customer-outage-minutes-avoided	157,056
3		DISTA GREENSPIRE03_TWELFTH STREET02	568	1	Loop	Automation - ATR Loops	KAL	Customer-outage-minutes-avoided	240,720
4		DISTA STURGEON03_LARKIN01	592	1	Loop	Automation - ATR Loops	MDL	Customer-outage-minutes-avoided	58,704
5		DISTA GRANT DISTA TECUMSEH01_HENDERSHOT01	367	1	Loop	Automation - ATR Loops	ADR	Customer-outage-minutes-avoided	106,992
6		DISTA GREENSPIRE02_PORTAGE01	490	1	Loop	Automation - ATR Loops	KAL	Customer-outage-minutes-avoided	307,200
7		DISTA SPRING LAKE02_SAVIDGE01	367	1	Loop	Automation - ATR Loops	MUS	Customer-outage-minutes-avoided	25,632
8		DISTA CAMDEN02_READING02	469	1	Loop	Automation - ATR Loops	CLD	Customer-outage-minutes-avoided	45,792
9		DISTA MORRELL01_WILDWOOD01	757	1	Loop	Automation - ATR Loops	JAC	Customer-outage-minutes-avoided	151,872
10		DISTA KEARSLEY01_GENESEEVILLE01	914	1	Loop	Automation - ATR Loops	FLT	Customer-outage-minutes-avoided	126,816
11		DISTA BARNARD02_DAVENPORT01	574	1	Loop	Automation - ATR Loops	SAG	Customer-outage-minutes-avoided	336,912
12		DISTA VILLAGE GREEN02_KILGORE01	367	1	Loop	Automation - ATR Loops	KAL	Customer-outage-minutes-avoided	45,312
13		DISTA NORTON02_McCRACKEN01	967	1	Loop	Automation - ATR Loops	MUS	Customer-outage-minutes-avoided	59,712
14		DISTA GRASS LAKE01_SYLVAN02	2,051	1	Loop	Automation - ATR Loops	JAC	Customer-outage-minutes-avoided	138,816
15		DISTA BELLEVUE02_OLIVET02	803	1	Loop	Automation - ATR Loops	BCK	Customer-outage-minutes-avoided	38,880
16		DISTA LETTS ROAD01_LETTS ROAD02	367	1	Loop	Automation - ATR Loops	MDL	Customer-outage-minutes-avoided	198,000
17		DISTA BURROWS02_BURROWS01	367	1	Loop	Automation - ATR Loops	SAG	Customer-outage-minutes-avoided	30,960
18		DISTA CRAHEN02_FULTON02	367	1	Loop	Automation - ATR Loops	GRA	Customer-outage-minutes-avoided	100,128
19		DISTA WHITEHALL02_BENSTON03	662	1	Loop	Automation - ATR Loops	MUS	Customer-outage-minutes-avoided	100,128
20		DISTA HARPER ROAD04_KIPP ROAD04 UPGRADE	490	1	Loop	Automation - ATR Loops	LAN	Customer-outage-minutes-avoided	85,920
21		DISTA CENTER ROAD02_BELSAY01	490	1	Loop	Automation - ATR Loops	FLT	Customer-outage-minutes-avoided	46,224
22		DISTA HILL ROAD03_BISHOP04	469	1	Loop	Automation - ATR Loops	FLT	Customer-outage-minutes-avoided	47,088
23		DISTA BALZER01_KIPP ROAD02	367	1	Loop	Automation - ATR Loops	LAN	Customer-outage-minutes-avoided	115,248
24		DISTA HOMER02_CONCORD02	1,119	1	Loop	Automation - ATR Loops	CLD	Customer-outage-minutes-avoided	48,912
25		DISTA DIMONDALE01_DIMONDALE03	641	1	Loop	Automation - ATR Loops	LAN	Customer-outage-minutes-avoided	430,944
26		DISTA MCCANDLISH02_ATLAS01	469	1	Loop	Automation - ATR Loops	FLT	Customer-outage-minutes-avoided	47,904
27		DISTA PULLMAN01_SWAN CREEK01	592	1	Loop	Automation - ATR Loops	HML	Customer-outage-minutes-avoided	144,096
28		DISTA FINE LAKE02_BROGAN02	367	1	Loop	Automation - ATR Loops	BCK	Customer-outage-minutes-avoided	38,880
29		DISTA AUSTIN01_AUSTIN02	245	1	Loop	Automation - ATR Loops	BCK	Customer-outage-minutes-avoided	22,176
30		DISTA SARANAC03_SARANAC04	728	1	Loop	Automation - ATR Loops	BCK	Customer-outage-minutes-avoided	49,200
31		**LVD Lines Reliability Subtotal**	**17,668**						
32		**LVD Lines Reliability Total**	**250,625**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT ONSTED-ONSTED LCP 389	106	1	Project	Repetitive Outage Projects	ADRIAN	Reduce Repeated Outages; Customer-outage-minutes avoid	94,481
2		RPOUT PITTSFORD-CHURCH ROAD LCP 525	129	1	Project	Repetitive Outage Projects	ADRIAN	Reduce Repeated Outages; Customer-outage-minutes avoid	114,703
3		RPOUT HUDSON-WATERWORKS LCP 880	312	1	Project	Repetitive Outage Projects	ADRIAN	Reduce Repeated Outages; Customer-outage-minutes avoid	177,309
4		RPOUT CASINO-LEATON LCP 276	183	1	Project	Repetitive Outage Projects	ALMA	Reduce Repeated Outages; Customer-outage-minutes avoid	162,247
5		RPOUT GILSON-WYMAN LCP 460	265	1	Project	Repetitive Outage Projects	ALMA	Reduce Repeated Outages; Customer-outage-minutes avoid	35,234
6		RPOUT CONVIS-CONVIS LCP 311	152	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	134,895
7		RPOUT MORGAN-ST MARYS LCP 248	57	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	50,722
8		RPOUT MORGAN-ST MARYS LCP 317	323	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	86,510
9		RPOUT MORGAN-ST MARYS LCP 386	159	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	140,795
10		RPOUT OLIVET-COLLEGE LCP 158	180	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	159,616
11		RPOUT MORGAN-ORCHARD LCP 24	220	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	195,576
12		RPOUT MORGAN-ST MARYS LCP 176	284	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	152,359
13		RPOUT FIFTEEN MILE ROAD-A DRIVE LCP CKT	256	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	127,440
14		RPOUT FINE LAKE-BRISTOL LCP 417	294	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	161,072
15		RPOUT CONVIS-WALNUT POINT LCP 9	366	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	25,185
16		RPOUT JOPPA-BECKLEY LCP 868	266	1	Project	Repetitive Outage Projects	BATTLE CREEK	Reduce Repeated Outages; Customer-outage-minutes avoid	136,359
17		RPOUT ARCADIA-STARKE LCP 553	211	1	Project	Repetitive Outage Projects	BENZONIA	Reduce Repeated Outages; Customer-outage-minutes avoid	87,131
18		RPOUT FRANKFORT-CRYSTALLIA LCP 360	87	1	Project	Repetitive Outage Projects	BENZONIA	Reduce Repeated Outages; Customer-outage-minutes avoid	77,317
19		RPOUT HOMESTEAD-BEULAH LCP 207	156	1	Project	Repetitive Outage Projects	BENZONIA	Reduce Repeated Outages; Customer-outage-minutes avoid	138,483
20		RPOUT HOMESTEAD-BEULAH LCP 186	273	1	Project	Repetitive Outage Projects	BENZONIA	Reduce Repeated Outages; Customer-outage-minutes avoid	242,545
21		RPOUT ARCADIA-STARKE LCP 577	197	1	Project	Repetitive Outage Projects	BENZONIA	Reduce Repeated Outages; Customer-outage-minutes avoid	174,804
22		RPOUT HONOR-PLATTE LCP 144	274	1	Project	Repetitive Outage Projects	BENZONIA	Reduce Repeated Outages; Customer-outage-minutes avoid	143,748
23		RPOUT BIG PRAIRIE-BIG BEND LCP 532	142	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	126,343
24		RPOUT BIG PRAIRIE-OXBOW LCP 878	149	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	132,548
25		RPOUT MILTON-MILLPOND LCP 809	70	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	62,604
26		RPOUT NINETEEN MILE RD-CEMENT LCP 529	115	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	102,034
27		RPOUT CONKLIN PARK-HOLLY LCP 922	153	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	136,146
28		RPOUT CONKLIN PARK-CROTON LCP 946	178	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	157,825
29		RPOUT RODNEY-HORSE HEAD LAKE LCP 352	310	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	175,255
30		RPOUT APPLETON-WALDRON WAY LCP 444	203	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	180,592
31		RPOUT BARRYTON-CHIPPEWA LAKE LCP 496	130	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	115,687
32		RPOUT OHMAN ROAD-HERSEY LCP 623	289	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	256,575
33		RPOUT BARRYTON-BARRYTON LCP 255	163	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	145,143
34		RPOUT RODNEY-HORSE HEAD LAKE LCP 337	287	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	154,745
35		RPOUT OHMAN ROAD-HERSEY LCP 403	276	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	145,504
36		RPOUT OHMAN ROAD-SEARS LCP 858	288	1	Project	Repetitive Outage Projects	BIG RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoid	55,931
37		RPOUT BAGLEY-OTSEGO LAKE LCP 196	39	1	Project	Repetitive Outage Projects	BOYNE CITY	Reduce Repeated Outages; Customer-outage-minutes avoid	34,829
38		RPOUT INDIAN RIVER-TOPINABEE LCP 603	82	1	Project	Repetitive Outage Projects	BOYNE CITY	Reduce Repeated Outages; Customer-outage-minutes avoid	72,492
39		RPOUT VANDERBILT-CORWITH LCP 248	205	1	Project	Repetitive Outage Projects	BOYNE CITY	Reduce Repeated Outages; Customer-outage-minutes avoid	182,363
40		RPOUT WALLOON-WATERWORKS LCP 500	139	1	Project	Repetitive Outage Projects	BOYNE CITY	Reduce Repeated Outages; Customer-outage-minutes avoid	123,128
41		RPOUT MACKINAW CITY-POND STREET LCP 504	119	1	Project	Repetitive Outage Projects	BOYNE CITY	Reduce Repeated Outages; Customer-outage-minutes avoid	106,106
42		RPOUT MURNER-VAN TYLE LCP CKT	145	1	Project	Repetitive Outage Projects	BOYNE CITY	Reduce Repeated Outages; Customer-outage-minutes avoid	128,901
43		RPOUT INDIAN RIVER-TOPINABEE LCP 659	264	1	Project	Repetitive Outage Projects	BOYNE CITY	Reduce Repeated Outages; Customer-outage-minutes avoid	34,728
44		RPOUT BAGLEY-OTSEGO LAKE LCP CKT	286	1	Project	Repetitive Outage Projects	BOYNE CITY	Reduce Repeated Outages; Customer-outage-minutes avoid	154,291
45		RPOUT BEHNKE-ANGOLA ROAD LCP 755	49	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	43,214
46		RPOUT WOODWARD-PLEASANT LAKE LCP 984	37	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	32,798
47		RPOUT MCBAIN-VOGEL CENTER LCP 200	168	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	148,911
48		RPOUT HARRIETTA-BOON LCP 744	207	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	183,982
49		RPOUT MESICK-SHERMAN LCP 237	373	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	330,957
50		RPOUT TUSTIN-LUTHER LCP 832	735	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	652,780
51		RPOUT HARRIETTA-BOON LCP 717	567	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	503,665
52		RPOUT KINDERHOOK-LAKE DRIVE LCP 756	126	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	111,903
53		RPOUT COLON-COLON LCP 816	229	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	203,463
54		RPOUT BEHNKE-ANGOLA ROAD LCP 440	236	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	209,775
55		RPOUT BABCOCK-FRANCISCO LCP 117	112	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	99,355
56		RPOUT READING-CAMBRIA LCP 750	275	1	Project	Repetitive Outage Projects	CADILLAC	Reduce Repeated Outages; Customer-outage-minutes avoid	193,983
57		RPOUT FROST-LONG LAKE LCP 267	81	1	Project	Repetitive Outage Projects	CLARE	Reduce Repeated Outages; Customer-outage-minutes avoid	72,322
58		RPOUT HARRISON-LILLEY LAKE LCP 334	93	1	Project	Repetitive Outage Projects	CLARE	Reduce Repeated Outages; Customer-outage-minutes avoid	82,781
59		RPOUT OBERLIN-BENMARK LCP 967	63	1	Project	Repetitive Outage Projects	CLARE	Reduce Repeated Outages; Customer-outage-minutes avoid	56,245
60		**Repetitive Outages Subtotal**	**12,138**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-168 (JMP-2)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT HARRISON-HARRISON LCP 5926	159	1	Project	Repetitive Outage Projects	CLARE	Reduce Repeated Outages; Customer-outage-minutes avoided	140,968
2		RPOUT CLARE-FARWELL LCP 368	202	1	Project	Repetitive Outage Projects	CLARE	Reduce Repeated Outages; Customer-outage-minutes avoided	179,457
3		RPOUT CASCADE-THORNCREST LCP 481	126	1	Project	Repetitive Outage Projects	EAST KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	111,676
4		RPOUT FOREMAN-VERGENNES LCP 533	74	1	Project	Repetitive Outage Projects	EAST KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	65,510
5		RPOUT MONTROSE-VOLKMER LCP 995	79	1	Project	Repetitive Outage Projects	FLINT	Reduce Repeated Outages; Customer-outage-minutes avoided	70,490
6		RPOUT GENESEEVILLE-PINEWOOD LCP CKT	119	1	Project	Repetitive Outage Projects	FLINT	Reduce Repeated Outages; Customer-outage-minutes avoided	105,349
7		RPOUT SKYLARK-RIVERBEND LCP 300	215	1	Project	Repetitive Outage Projects	FLINT	Reduce Repeated Outages; Customer-outage-minutes avoided	190,737
8		RPOUT JUDD ROAD-AINSWORTH LCP 689	284	1	Project	Repetitive Outage Projects	FLINT	Reduce Repeated Outages; Customer-outage-minutes avoided	152,081
9		RPOUT HESPERIA-RURAL LCP 938	79	1	Project	Repetitive Outage Projects	FREMONT	Reduce Repeated Outages; Customer-outage-minutes avoided	70,384
10		RPOUT ABERDEEN-HOLLYWOOD LCP 755	96	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	85,330
11		RPOUT BYRON CENTER-BYRON CENTER LCP 428	102	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	90,514
12		RPOUT FILLMORE-NORTH BLENDON LCP 554	32	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	28,487
13		RPOUT FOREST GROVE-OTTOGAN LCP 514	145	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	128,343
14		RPOUT LEFFINGWELL-MICHIGAN OAKS LCP 12	93	1	Project	Repetitive Outage Projects	GRAND RAPIDS	Reduce Repeated Outages; Customer-outage-minutes avoided	82,811
15		RPOUT BELDING-COOKS CORNERS LCP 83	61	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	54,279
16		RPOUT ORLEANS-ORLEANS LCP 67	201	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	178,185
17		RPOUT SANDERSON-COUNTY FARM LCP 414	102	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	90,636
18		RPOUT STANTON-DICKERSON LAKE LCP 6	97	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	86,179
19		RPOUT TREMAINE-JORDAN LAKE LCP 563	30	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	26,198
20		RPOUT TRUFANT-MASTON LAKE LCP 206	84	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	74,342
21		RPOUT SHERIDAN-FENWICK LCP 826	175	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	155,481
22		RPOUT HARVARD LAKE-COURTLAND LCP 603	327	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	180,520
23		RPOUT LYONS-COLLINS-RURAL LCP 172	220	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	195,067
24		RPOUT SARANAC-CENTERLINE LCP 509	203	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	180,622
25		RPOUT SARANAC-RIVERSIDE LCP 732	146	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	129,885
26		RPOUT SHERIDAN-SIDNEY LCP 3	197	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	175,287
27		RPOUT PALO-PALO LCP 198	281	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	249,964
28		RPOUT PALO-PALO LCP 573	136	1	Project	Repetitive Outage Projects	GREENVILLE	Reduce Repeated Outages; Customer-outage-minutes avoided	120,652
29		RPOUT CASCO-HAWKHEAD LCP 466	106	1	Project	Repetitive Outage Projects	HAMILTON	Reduce Repeated Outages; Customer-outage-minutes avoided	93,770
30		RPOUT PIGEON LAKE-PIGEON LCP 871	116	1	Project	Repetitive Outage Projects	HAMILTON	Reduce Repeated Outages; Customer-outage-minutes avoided	103,109
31		RPOUT VIRGINIA PARK-CASTLE LCP 901	88	1	Project	Repetitive Outage Projects	HAMILTON	Reduce Repeated Outages; Customer-outage-minutes avoided	78,074
32		RPOUT WILLIAMS-ELY LCP 366	120	1	Project	Repetitive Outage Projects	HAMILTON	Reduce Repeated Outages; Customer-outage-minutes avoided	106,687
33		RPOUT BITTERSWEET-RIVER ROAD LCP 753	237	1	Project	Repetitive Outage Projects	HAMILTON	Reduce Repeated Outages; Customer-outage-minutes avoided	110,116
34		RPOUT SAUGATUCK-SILVER LAKE LCP 984	128	1	Project	Repetitive Outage Projects	HAMILTON	Reduce Repeated Outages; Customer-outage-minutes avoided	114,098
35		RPOUT FENNVILLE-PEACH BELT LCP 191	89	1	Project	Repetitive Outage Projects	HAMILTON	Reduce Repeated Outages; Customer-outage-minutes avoided	78,772
36		RPOUT DELTON-DELTON LCP 122	137	1	Project	Repetitive Outage Projects	HASTINGS	Reduce Repeated Outages; Customer-outage-minutes avoided	121,954
37		RPOUT DELTON-CLOVERDALE LCP 964	272	1	Project	Repetitive Outage Projects	HASTINGS	Reduce Repeated Outages; Customer-outage-minutes avoided	241,922
38		RPOUT HANOVER-HORTON LCP 404	149	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	132,422
39		RPOUT HANOVER-HORTON LCP 507	146	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	129,843
40		RPOUT PARMA-BALDWIN LCP 15	201	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	178,654
41		RPOUT ROBERTS STREET-DETTMAN LCP 828	32	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	28,359
42		RPOUT SCIPIO-POPE ROAD LCP 691	49	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	43,930
43		RPOUT STOCKBRIDGE-STOCKBRIDGE LCP 576	70	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	62,513
44		RPOUT WILLIS ROAD-LIST ROAD LCP 210	224	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	199,285
45		RPOUT MAINES ROAD-WELLMAN ROAD LCP 113	130	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	115,472
46		RPOUT GRASS LAKE-GRASS LAKE LCP 8	317	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	281,264
47		RPOUT CONCORD-KING ROAD LCP 36	106	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	94,133
48		RPOUT SPRINGPORT-DEVEREAUX LCP 426	219	1	Project	Repetitive Outage Projects	JACKSON	Reduce Repeated Outages; Customer-outage-minutes avoided	194,377
49		RPOUT ALAMO-FISH HATCHERY LCP 736	74	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	65,757
50		RPOUT ALAMO-OWEN LCP 222	66	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	58,517
51		RPOUT ALAMO-OWEN LCP 364	127	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	112,781
52		RPOUT AUGUSTA-AUGUSTA LCP 684	84	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	74,652
53		RPOUT ELEVENTH STREET-BASELINE LCP 405	56	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	50,036
54		RPOUT GALESBURG-GALESBURG LCP 295	86	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	76,196
55		RPOUT PICKEREL-INDIAN LAKE LCP 803	128	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	114,098
56		RPOUT PORTAGE-CARPENTERS CORNERS LCP 133	57	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	50,232
57		RPOUT LAWRENCE-CHRISTIE LAKE LCP 675	201	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	178,791
58		RPOUT GALESBURG-CHARLESTON LCP 464	174	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	154,315
59		RPOUT BREEDSVILLE-GRAND JUNCTION LCP 823	197	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	175,188
60		RPOUT WARNER-MILO LCP 107	241	1	Project	Repetitive Outage Projects	KALAMAZOO	Reduce Repeated Outages; Customer-outage-minutes avoided	213,727
61		**Repetitive Outages Subtotal**	**8,494**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-168 (JMP-2)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Repetitive Outages	RPOUT PEACOCK-STOLL ROAD LCP 420	106	1	Project	Repetitive Outage Projects	LANSING	Reduce Repeated Outages; Customer-outage-minutes avoided	93,800
2		RPOUT PEACOCK-STOLL ROAD LCP 462	168	1	Project	Repetitive Outage Projects	LANSING	Reduce Repeated Outages; Customer-outage-minutes avoided	149,122
3		RPOUT FOX FARM-GRANT LCP 599	78	1	Project	Repetitive Outage Projects	LUDINGTON	Reduce Repeated Outages; Customer-outage-minutes avoided	69,546
4		RPOUT CAMELOT LAKE-LOOMIS LCP 132	259	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	229,945
5		RPOUT LETTS ROAD-MONROE ROAD LCP 212	177	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	156,888
6		RPOUT PRICE ROAD-MERIDIAN LCP 530	60	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	52,992
7		RPOUT LEVELY-STURGEON LCP 11	148	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	131,157
8		RPOUT THORNTON-WEST RIVER RD LCP 691	225	1	Project	Repetitive Outage Projects	MIDLAND	Reduce Repeated Outages; Customer-outage-minutes avoided	199,679
9		RPOUT AGNEW-WEYBURN LCP 309	128	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	113,326
10		RPOUT BENSTON-DURHAM LCP 730	47	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	41,501
11		RPOUT DENNISON-SOUTH POLKTON LCP 433	48	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	42,488
12		RPOUT DUPONT-OLD CHANNEL LCP 644	143	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	127,418
13		RPOUT KEATING-WOOD STREET LCP 3813	14	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	12,215
14		RPOUT NESTROM-SCENIC DRIVE LCP 244	62	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	55,005
15		RPOUT NESTROM-SOUTH SHORE LCP 294	171	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	151,560
16		RPOUT NUNICA-WILSON LCP 410	56	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	49,577
17		RPOUT NUNICA-WILSON LCP 568	175	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	155,260
18		RPOUT SPRING LAKE-SPRING LAKE LCP 281	89	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	78,780
19		RPOUT NORTON-PONTALUNA ROAD LCP 335	100	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	88,941
20		RPOUT FRUITPORT-JUDSON ROAD LCP 642	164	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	145,637
21		RPOUT NUNICA-WILSON LCP 663	281	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	149,734
22		RPOUT MCMILLAN-BEATTIE LCP 275	155	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	137,463
23		RPOUT RAVENNA-MOORLAND LCP 177	341	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	202,624
24		RPOUT NESTROM-SOUTH SHORE LCP 560	271	1	Project	Repetitive Outage Projects	MUSKEGON	Reduce Repeated Outages; Customer-outage-minutes avoided	140,986
25		RPOUT CEDAR SPRINGS-NELSON LCP 333	143	1	Project	Repetitive Outage Projects	NORTH KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	126,778
26		RPOUT HULL STREET-CRANBERRY LCP 329	63	1	Project	Repetitive Outage Projects	NORTH KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	55,702
27		RPOUT HULL STREET-CRANBERRY LCP 86	188	1	Project	Repetitive Outage Projects	NORTH KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	166,845
28		RPOUT KENT CITY-TYRONE LCP 529	13	1	Project	Repetitive Outage Projects	NORTH KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	11,125
29		RPOUT PIERSON-PIERSON LCP 284	114	1	Project	Repetitive Outage Projects	NORTH KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	101,368
30		RPOUT PETTIS ROAD-HONEY CREEK LCP 988	179	1	Project	Repetitive Outage Projects	NORTH KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	158,765
31		RPOUT LAMOREAUX-LAMOREAUX LCP 495	136	1	Project	Repetitive Outage Projects	NORTH KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	120,334
32		RPOUT CANNONSBURG-WEST CANNON LCP 379	264	1	Project	Repetitive Outage Projects	NORTH KENT	Reduce Repeated Outages; Customer-outage-minutes avoided	234,402
33		RPOUT NEWBURG-BANCROFT LCP 273	113	1	Project	Repetitive Outage Projects	OWOSSO	Reduce Repeated Outages; Customer-outage-minutes avoided	100,626
34		RPOUT JEFFS ROAD-ADLER ROAD LCP 159	25	1	Project	Repetitive Outage Projects	SOUTH MONROE	Reduce Repeated Outages; Customer-outage-minutes avoided	22,190
35		RPOUT HUBBARD LAKE-HUBBARD LAKE LCP CKT	208	1	Project	Repetitive Outage Projects	TAWAS	Reduce Repeated Outages; Customer-outage-minutes avoided	184,882
36		RPOUT OSCODA-BUTLER HEIGHTS LCP 313	33	1	Project	Repetitive Outage Projects	TAWAS	Reduce Repeated Outages; Customer-outage-minutes avoided	29,477
37		RPOUT RANGER LAKE-LUPTON LCP 71	80	1	Project	Repetitive Outage Projects	TAWAS	Reduce Repeated Outages; Customer-outage-minutes avoided	71,335
38		RPOUT GLEN LAKE-BURDICKVILLE LCP 960	84	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	74,388
39		RPOUT LEELANAU-BELANGER CREEK LCP 7013	152	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	134,835
40		RPOUT LEELANAU-OMENA BAY LCP 679	39	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	34,344
41		RPOUT LELAND-LELAND LCP 240	115	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	102,523
42		RPOUT LELAND-LELAND LCP 399	120	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	106,136
43		RPOUT LELAND-LELAND LCP 6715	168	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	149,260
44		RPOUT MAPLE CITY-CEDAR LCP 724	47	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	41,886
45		RPOUT MAPLE CITY-CEDAR LCP 728	134	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	118,987
46		RPOUT SILVER LAKE-SILVER PINES LCP 5016	43	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	37,751
47		RPOUT MAPLE CITY-SUGAR LOAF LCP 109	152	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	134,686
48		RPOUT LELAND-LELAND LCP CKT	224	1	Project	Repetitive Outage Projects	TRAVERSE CITY	Reduce Repeated Outages; Customer-outage-minutes avoided	198,811
49		RPOUT ALGER-SKIDWAY LCP CKT	26	1	Project	Repetitive Outage Projects	WEST BRANCH	Reduce Repeated Outages; Customer-outage-minutes avoided	22,674
50		RPOUT MARKEY-CARRICK LCP 456	209	1	Project	Repetitive Outage Projects	WEST BRANCH	Reduce Repeated Outages; Customer-outage-minutes avoided	185,489
51		RPOUT SMITH CREEK-WRIGHT LCP 5039	209	1	Project	Repetitive Outage Projects	WEST BRANCH	Reduce Repeated Outages; Customer-outage-minutes avoided	185,224
52		RPOUT GRAYLING-RIVER LCP CKT	120	1	Project	Repetitive Outage Projects	WEST BRANCH	Reduce Repeated Outages; Customer-outage-minutes avoided	106,317
53		**Repetitive Outages Subtotal**	**6,861**						
54		**Repetitive Outages Total**	**27,493**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-168 (JMP-2)
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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA FLETCHER_ODEN LCP 264 NLO	25	1	Project	Imminent Rehabilitation	EMMET	Improve Secondary Voltage ; Customers	5
2		FA MARSHALL ST JACKSON	5	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
3		FA HOWARD ST JACKSON	6	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
4		FA W MONROE ST JACKSON	6	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
5		FA LOOMIS ST JACKSON	6	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
6		FA KENNEDY ST JACKSON	6	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
7		FA GILBERT ST JACKSON	6	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
8		FA N PLEASANT ST JACKSON	6	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
9		FA BATES ST JACKSON	6	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
10		FA BLOOMFIELD BLVD JACKSON	6	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
11		FA CRESCENT RD JACKSON	6	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
12		FA PARKWOOD WAY JACKSON	100	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
13		FA GLENWOOD AVE JACKSON	9	1	Project	Imminent Rehabilitation	JACKSON	Improve Primary Voltage ; Customers	520
14		FA-E 12TH ST, WHITE CLOUD-SVLT	26	1	Project	Imminent Rehabilitation	NEWAYGO	Improve Secondary Voltage ; Customers	5
15		FA - N Baldwin Rd, Ithaca - FLRE	4	1	Project	Imminent Rehabilitation	GRATIOT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
16		FA 154th st AGNEW_WEYBURN UGL	250	1	Project	Imminent Rehabilitation	OTTAWA	Replace Deteriorated Underground Primary ; Customers	43
17		FA - 9731 PORT SHELDON ST ZEELAND-SVLT	5	1	Project	Imminent Rehabilitation	OTTAWA	Improve Secondary Voltage ; Customers	5
18		FA N. Rodgers Ct - SVLT	31	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
19		FA LAKE DR SE, GR - FAIL STLT	5	1	Project	Imminent Rehabilitation	KENT	Repair Damaged Streetlight ; Customers	0
20		FA-SHATTUCK RD, SAGINAW-SVLT	25	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
21		FA-HARRIS DR-CARY_WOODSTOCK	26	1	Project	Imminent Rehabilitation	LENAWEE	Improve Secondary Voltage ; Customers	5
22		FA - R Dr N Olivet - CAPS	20	1	Project	Imminent Rehabilitation	CALHOUN	Improve Primary Voltage ; Customers	520
23		FA AULERICH RD ETAW ESIC OHL	9	1	Project	Imminent Rehabilitation	IOSCO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
24		FA Charles St Muskegon	24	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Primary Voltage ; Customers	520
25		FA-BARD GLD RP POLE AND DEMO	10	1	Project	Imminent Rehabilitation	GLADWIN	Replace Deteriorated Pole ; Customers	242
26		FA - 010202 LCP 131 - FLRE	5	1	Project	Imminent Rehabilitation	EATON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
27		FA - 48TH AVE, HUDSONVILLE - OHC2	6	1	Project	Imminent Rehabilitation	OTTAWA	Correct Conductor Clearance Violation ; Customers	24
28		FA-N RIDGEWOOD, LAMBERTVILLE-VOLT	9	1	Project	Imminent Rehabilitation	MONROE	Improve Primary Voltage ; Customers	520
29		FA-JACKSON ST RCMN PRI	30	1	Project	Imminent Rehabilitation	ROSCOMMON	Correct Conductor Clearance Violation ; Customers	24
30		FA - BROOKLYN RD, JACKSON - OHC1	30	1	Project	Imminent Rehabilitation	JACKSON	Correct Conductor Clearance Violation ; Customers	20
31		FA Lake Harbor Ro. Norton Pontaluna	83	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Underground Primary ; Customers	43
32		FA M-46 RAVENNA_MOORLAND	150	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
33		FA_ROSE CITY_KLACKING CREEK LCP 5023 REG	11	1	Project	Imminent Rehabilitation	OGEMAW	Improve Primary Voltage ; Customers	520
34		FA Leonard -SAVIDGE_BOOM ROAD	6	1	Project	Imminent Rehabilitation	OTTAWA	Improve Secondary Voltage ; Customers	5
35		FA- W Savidge St Spring Lake	42	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	5
36		FA - STANDALE_STANDALE LCP 112 PVLT	4	1	Project	Imminent Rehabilitation	KENT	Improve Primary Voltage ; Customers	520
37		BUCHANAN AVE/COTTAGE GROVE - switch - A1	55	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Underground Primary ; Customers	43
38		FA - W MONROE RD, TECUMSEH - SVLT	12	1	Project	Imminent Rehabilitation	LENAWEE	Improve Secondary Voltage ; Customers	5
39		FA POLE UPTON_MT HOPE LCP 724	15	1	Project	Imminent Rehabilitation	EATON	Replace Deteriorated Pole ; Customers	242
40		FA WALDRON_MUNSON LCP 243 OH WIRERP	92	1	Project	Imminent Rehabilitation	LENAWEE	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
41		FA - MINGES RD E - FLRE	10	1	Project	Imminent Rehabilitation	CALHOUN	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
42		FA - CAMDEN AVE SW WYOMING SVLT	13	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
43		FA - 13385 W TOWNLINE RD,ST. CHLS	75	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Regulator ; Customers	155
44		FA BAY ROAD/BELL	120	1	Project	Imminent Rehabilitation	SAGINAW	Improve Primary Voltage ; Customers	520
45		FA JANET DR, DORR - SYS UPGRADE	120	1	Project	Imminent Rehabilitation	ALLEGAN	Improve Primary Voltage ; Customers	520
46		FA 215 S MAIN ST, Sheridan Low 3/0 Quad	20	1	Project	Imminent Rehabilitation	MONTCALM	Correct Conductor Clearance Violation ; Customers	24
47		FA ALASKA AVE SE CALEDONIA*ESIC	25	1	Project	Imminent Rehabilitation	KENT	Improve Secondary Voltage ; Customers	5
48		FA 144TH, SPRING LAKE- STLT*	10	1	Project	Imminent Rehabilitation	OTTAWA	Repair Damaged Streetlight ; Customers	0
49		FA ABERDEEN/KNAPP ol fuses and coord	17	1	Project	Imminent Rehabilitation	KENT	Improve Primary Voltage ; Customers	520
50		STLT US HWY 31 & FIRST ST, ELK RAPIDS	15	1	Project	Imminent Rehabilitation	ANTRIM	Repair Damaged Streetlight ; Customers	0
51		FA Brooklyn_Brooklyn RP SS CUTOUTS	22	1	Project	Imminent Rehabilitation	JACKSON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
52		FA CARSON CITY_BUTTERNUT	404	1	Project	Imminent Rehabilitation	MONTCALM	Improve Secondary Voltage ; Customers	5
53		FA 1296 ISLAND HWY CHARLOTTE	4	1	Project	Imminent Rehabilitation	EATON	Replace Deteriorated Pole ; Customers	242
54		FA BROWNELL GR	15	1	Project	Imminent Rehabilitation	KENT	Improve Primary Voltage ; Customers	520
55		FA Dewey Seating - OHC2	5	1	Project	Imminent Rehabilitation	KENT	Correct Conductor Clearance Violation ; Customers	24
56		FA DIMONDALE M99 LCP 061 REG	19	1	Project	Imminent Rehabilitation	INGHAM	Replace Deteriorated Regulator ; Customers	155
57		FA ELM STREET_VAN BUREN	33	1	Project	Imminent Rehabilitation	CALHOUN	Improve Primary Voltage ; Customers	520
58		FA ENSLEY/BAPTIST LAKE LCP 741	15	1	Project	Imminent Rehabilitation	NEWAYGO	Improve Primary Voltage ; Customers	520
59		FA-WINDING WAY GALESBURG	17	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	5
60		FA GLADWIN CEDAR LCP 939	45	1	Project	Imminent Rehabilitation	GLADWIN	Improve Primary Voltage ; Customers	520
61		FA LAKE MICHIGAN DR UG RECOND	62	1	Project	Imminent Rehabilitation	OTTAWA	Replace Deteriorated Underground Primary ; Customers	43
62		FA GROVER/TRIANGLE Jerome Rd OH	16	1	Project	Imminent Rehabilitation		Improve Primary Voltage ; Customers	520
63		FA HARRISON LILLY LK LCP 774 & 541	8	1	Project	Imminent Rehabilitation	CLARE	Improve Primary Voltage ; Customers	520
64		FA HASTINGS/VIKING LCP 328 UG CBL	31	1	Project	Imminent Rehabilitation	BARRY	Replace Deteriorated Underground Primary ; Customers	43
65		FA S LAKE MICHIGAN DR EMPIRE-deq	15	1	Project	Imminent Rehabilitation	LEELANAU	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
66		**Imminent Rehabilitation Subtotal**	**2,315**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA Sarah Ln, CLD-reloc pole fail	4	1	Project	Imminent Rehabilitation	BRANCH	Replace Deteriorated Pole ; Customers	242
2		FA KNAPP/PERKINS LOAD TRANSFER 2	363	1	Project	Imminent Rehabilitation	KENT	Improve Primary Voltage ; Customers	520
3		FA LEVEL PARK_LEVEL PARK	16	1	Project	Imminent Rehabilitation	CALHOUN	Improve Primary Voltage ; Customers	520
4		FA LOMBARD SHERIDAN LCP 546	10	1	Project	Imminent Rehabilitation	CALHOUN	Improve Primary Voltage ; Customers	520
5		FA M 99 ALBION	8	1	Project	Imminent Rehabilitation	CALHOUN	Improve Primary Voltage ; Customers	520
6		LOOMIS SUB-PRATT RD RP REG CABLE	5	1	Project	Imminent Rehabilitation	CLINTON	Replace Deteriorated Regulator ; Customers	155
7		FA GRAND BLVD #B, ROSC	11	1	Project	Imminent Rehabilitation	ROSCOMMON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
8		FA MANNSIDING CEDAR LCP 460	19	1	Project	Imminent Rehabilitation	CLARE	Improve Secondary Voltage ; Customers	5
9		FA - NEW RICHMOND-NEW RICHMOND	257	1	Project	Imminent Rehabilitation	ALLEGAN	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
10		FA Olivet College LCP 410	36	1	Project	Imminent Rehabilitation	EATON	Improve Primary Voltage ; Customers	520
11		FA UGLN Country Side Village PH I	553	1	Project	Imminent Rehabilitation	SHIAWASSEE	Replace Deteriorated Underground Primary ; Customers	43
12		FA LEONARD ST NW GRAND RAPIDS*BORE*	45	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Underground Primary ; Customers	43
13		FA Lake Michigan Dr NW - POLES	30	1	Project	Imminent Rehabilitation	OTTAWA	Replace Deteriorated Pole ; Customers	242
14		FA THORNAPPLE HEADLEY SARGENT AVE	28	1	Project	Imminent Rehabilitation	KENT	Improve Primary Voltage ; Customers	520
15		FA VILLAGE GREEN CONSTITUTION	35	1	Project	Imminent Rehabilitation	KALAMAZOO	Improve Secondary Voltage ; Customers	5
16		FA - BECKLEY RD	8	1	Project	Imminent Rehabilitation	CALHOUN	Improve Secondary Voltage ; Customers	5
17		FA WEIDMAN WEIDMAN LCP 821	21	1	Project	Imminent Rehabilitation	ISABELLA	Improve Secondary Voltage ; Customers	5
18		FA - OLD STATE RD, WHITTEMORE; FRRE	13	1	Project	Imminent Rehabilitation	IOSCO	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
19		WILLOW AVE PWTR / ESIC OHL	25	1	Project	Imminent Rehabilitation	MASON	Improve Secondary Voltage ; Customers	9
20		FA Winans st VOLT AGNEW_WEYBURN	125	1	Project	Imminent Rehabilitation	OTTAWA	Improve Primary Voltage ; Customers	131
21		FA SKEELS St COOPERSVILLE_CONKLIN	9	1	Project	Imminent Rehabilitation	OTTAWA	Improve Primary Voltage ; Customers	42
22		FA Pine st FRUITPORT_JUDSON ROAD	6	1	Project	Imminent Rehabilitation	MUSKEGON	Correct Conductor Clearance Violation ; Customers	2
23		FA Vick Road MONA LAKE_AIRPORT	72	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	21
24		FA - E DAVIS ST - POL2	59	1	Project	Imminent Rehabilitation	CLARE	Replace Deteriorated Pole ; Customers	242
25		FA - E DEERFIELD RD Mt P - SWCH	38	1	Project	Imminent Rehabilitation	ISABELLA	Replace Deteriorated Switch ; Customers	155
26		FA - N BLOCK RD, REESE - SVLT	32	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
27		CRITICAL FL - MARION RD. CHESANING	70	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
28		FA - S FOURTH ST, CHESANING - POL2	59	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Pole ; Customers	242
29		FA - CABARET TRL S, SAGINAW - PVLT	83	1	Project	Imminent Rehabilitation	SAGINAW	Improve Primary Voltage ; Customers	520
30		FA - EDDY ST, SAGINAW - RREG	20	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Regulator ; Customers	155
31		FA - WASHINGTON W/FINDLEY - PVLT	83	1	Project	Imminent Rehabilitation	SAGINAW	Improve Primary Voltage ; Customers	520
32		FA - LAWNDALE RD SAGINAW - SVLT	32	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
33		FA - MACKINAW RD, SAGINAW - SVLT	32	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
34		FA - S SILVERLEAF ST - PVLT	83	1	Project	Imminent Rehabilitation	GLADWIN	Improve Primary Voltage ; Customers	520
35		FA - MCCARTY RD, SAGINAW - SVLT	32	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
36		FA - GEDDES RD SAGINAW - SVLT	32	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
37		FA - CARDINAL SQUARE BLVD - SVLT	32	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
38		FA - S OUTER DR, SAGINAW - SVLT	32	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
39		CRITICAL FL - RATHBUN E/PETTIT	70	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
40		FA - VIRGINIA AVE SAGINAW - POL2	59	1	Project	Imminent Rehabilitation	SAGINAW	Replace Deteriorated Pole ; Customers	242
41		FA - W BURT RD, CHESANING - SVLT	32	1	Project	Imminent Rehabilitation	SAGINAW	Improve Secondary Voltage ; Customers	5
42		FA BELLA VISTA_BLAKELY FUSES	8	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
43		FA COWAN LAKE_RAMSDELL LCP-657 FUSES	16	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
44		FA ROCKFORD_SUMMIT LCP-695 FUSES	16	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
45		FA WEST RIVER_CHAMBERLIN FUSING	3	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
46		FA PLAINFIELD_WOOD COORDINATION	11	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
47		FA PLAINFIELD_BELMONT COORDINATION	6	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
48		FA Hughes Ave Norton Shores	33	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	12
49		FA W Hille Road NORTON_HILE ROAD LCP	30	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	8
50		FA Lake Harbor Ro. OHL	85	1	Project	Imminent Rehabilitation	MUSKEGON	Replace Deteriorated Pole or Pole Top Equipment ; Customers	8
51		FA - PROGRESS RD - TWNL - SYS UPG	44	1	Project	Imminent Rehabilitation	MUSKEGON	Improve Secondary Voltage ; Customers	84
52		CRITICAL FL - CALGARY ST SW - WYOMI	72	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole or Pole Top Equipment ; Customers	2
53		FA Rockfor_Freska Lk LCP-689	18	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Underground Primary ; Customers	43
54		FA TIFFANY AVE NE, ROCKFORD - POL2	2	1	Project	Imminent Rehabilitation	KENT	Replace Deteriorated Pole ; Customers	242
55		FA Carpenter Rd, Clearance	10	1	Project	Imminent Rehabilitation	COLDWATER	Correct Conductor Clearance Violation ; Customers	24
56		FA-HANOVER-PULASKI-CLEARANCE WOODEN	22	1	Project	Imminent Rehabilitation	JACKSON	Correct Conductor Clearance Violation ; Customers	24
57		FA-HANOVER-PULASKI-WOODEN RD W-O STO	22	1	Project	Imminent Rehabilitation	JACKSON	Correct Conductor Clearance Violation ; Customers	24
58		FA-HANOVER-PULASKI-xrd 10750 LUTTENT	6	1	Project	Imminent Rehabilitation	JACKSON	Correct Conductor Clearance Violation ; Customers	24
59		**Imminent Rehabilitation Subtotal**	2,984						
60		**Imminent Rehabilitation Total**	5,299						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	LVD Lines Rehabilitation	FA INGERSOLL ST - Ferrand Estates	**3,022**	1	Project	Vintage Underground Replacement	KENT	Replace Deteriorated Underground Primary ; Customers	429
2	LVD Lines Rehabilitation	Modem Replacements	**2,998**	800	Modems	Modem Replacement	STATEWIDE	Avoid Obsolescence	
3	LVD Lines Rehabilitation	Meter Voltage Anomalies	**11,658**	N/A			STATEWIDE	Regulatory Compliance	
4		**LVD Lines Rehabilitation Total**	**22,977**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Reliability								
1	Resiliency	Greenwood_M-33_606	825	1.5	miles	Overhead to Underground	Ogemaw Co.	Customer-outage-minutes avoided	61,365
2		Greenwood_M-33_819	1,000	2.5	miles	Overhead to Underground	Ogemaw Co.	Customer-outage-minutes avoided	35,483
3		Balcom_Bankers_736	420	1.2	miles	Overhead to Underground	Hillsdale Co.	Customer-outage-minutes avoided	30,819
4		Blue Star_Pier Cove_622	935	1.7	miles	Overhead to Underground	Allegan Co.	Customer-outage-minutes avoided	35,686
5		Bricker_Storey Road_228	1,913	5.1	miles	Overhead to Underground	Kent Co.	Customer-outage-minutes avoided	86,953
6		Brooklyn_Brooklyn_811	180	0.3	miles	Overhead to Underground	Jackson Co.	Customer-outage-minutes avoided	30,448
7		Casco_Hawkhead_516	287	0.7	miles	Overhead to Underground	Allegan Co.	Customer-outage-minutes avoided	22,005
8		Dean Road_hartland_951	900	2	miles	Overhead to Underground	Livingston Co.	Customer-outage-minutes avoided	75,471
9		Halls Lake_Halls Lake_173	1,173	2.3	miles	Overhead to Underground	Calhoun Co.	Customer-outage-minutes avoided	61,463
10		Hanover_Pulaski_532	1,680	4.2	miles	Overhead to Underground	Jackson Co.	Customer-outage-minutes avoided	117,839
11		Harvard Lake_Harvard Lake_986	2,242	5.9	miles	Overhead to Underground	Kent Co.	Customer-outage-minutes avoided	92,753
12		Kolassa_Matteson_187	480	0.8	miles	Overhead to Underground	Branch Co.	Customer-outage-minutes avoided	47,956
13		Lake Leann_Lake Leann_159	540	1.2	miles	Overhead to Underground	Hillsdale Co.	Customer-outage-minutes avoided	49,381
14		Lake Leann_Lake Leann_282	294	1	miles	Overhead to Underground	Jackson Co.	Customer-outage-minutes avoided	47,318
15		Maple Grove_Summitave _ 289	294	0.7	miles	Overhead to Underground	Muskegon Co.	Customer-outage-minutes avoided	10,363
16		Northport_Manitou_657	700	2	miles	Overhead to Underground	Leelanau Co.	Customer-outage-minutes avoided	68,864
17		Oak Street_Cooper Street_211	450	1.2	miles	Overhead to Underground	Jackson Co.	Customer-outage-minutes avoided	16,201
18		Peninsula_Mapleton_124	720	1.6	miles	Overhead to Underground	Grand Traverse Co.	Customer-outage-minutes avoided	55,599
19		Sherman_Sherman_0304	1,320	4.4	miles	Overhead to Underground	Iosco Co.	Customer-outage-minutes avoided	50,822
20		Spruce Road_East Bay_0693	405	0.9	miles	Overhead to Underground	Alcona Co.	Customer-outage-minutes avoided	51,908
21		Spruce Road_East Bay_0868	280	0.7	miles	Overhead to Underground	Alcona Co.	Customer-outage-minutes avoided	37,643
22		Whittemore_Bear Paw_28	270	0.9	miles	Overhead to Underground	Iosco Co.	Customer-outage-minutes avoided	436,554
23		Yorkville_Highland Park_182	520	1.3	miles	Overhead to Underground	Kalamazoo Co.	Customer-outage-minutes avoided	47,581
24		Gerrish_Merrio_248	1,372	4.9	miles	Overhead to Underground	Crawford Co.	Customer-outage-minutes avoided	55,599
25		**Overhead to Underground Total**	**19,200**						
26	Resiliency	MIEJ MCCRACKEN01_MAPLE GROVE01	3,483	1	Project	Resiliency - MIEJ Hardening	Muskegon	Customer-outage-minutes avoided	604,688
27		MIEJ MAUMEE02_BEECHER03	2,643	1	Project	Resiliency - MIEJ Hardening	Adrian	Customer-outage-minutes avoided	161,519
28		MIEJ RED ARROW04_IRON ST01	2,402	1	Project	Resiliency - MIEJ Hardening	Flint	Customer-outage-minutes avoided	261,356
29		MIEJ CALKINS01 SQUIRE_HILL01	3,243	1	Project	Resiliency - MIEJ Hardening	Grand Rapids	Customer-outage-minutes avoided	331,676
30		MIEJ CADMUS01_COLLEGE PARK02	1,922	1	Project	Resiliency - MIEJ Hardening	Adrian	Customer-outage-minutes avoided	138,329
31		MIEJ MONA LAKE01_MAPLE GROVE02	1,562	1	Project	Resiliency - MIEJ Hardening	Muskegon	Customer-outage-minutes avoided	567,791
32		MIEJ ROBERTS STREET03_EAST JACKSON01	3,123	1	Project	Resiliency - MIEJ Hardening	Jackson	Customer-outage-minutes avoided	135,930
33		MIEJ JUDD ROAD06_ATHERTON01	2,643	1	Project	Resiliency - MIEJ Hardening	Flint	Customer-outage-minutes avoided	310,756
34		MIEJ STADIUM01_COOLEY01	961	1	Project	Resiliency - MIEJ Hardening	Kalamazoo	Customer-outage-minutes avoided	109,903
35		MIEJ MUSKEGON HEIGHTS05_TERRACE02	2,523	1	Project	Resiliency - MIEJ Hardening	Muskegon	Customer-outage-minutes avoided	307,965
36		MIEJ MUSKEGON HEIGHTS02_KEATING01	2,042	1	Project	Resiliency - MIEJ Hardening	Muskegon	Customer-outage-minutes avoided	204,250
37		MIEJ MAPLE GROVE05_MUSKEGON HEIGHTS04	3,003	1	Project	Resiliency - MIEJ Hardening	Muskegon	Customer-outage-minutes avoided	185,846
38		MIEJ MUSKEGON HEIGHTS03_BROADWAY01	3,724	1	Project	Resiliency - MIEJ Hardening	Muskegon	Customer-outage-minutes avoided	329,633
39		MIEJ MUSKEGON HEIGHTS01_WESTEREN AVE04	2,763	1	Project	Resiliency - MIEJ Hardening	Muskegon	Customer-outage-minutes avoided	50,148
40		MIEJ WESTERN AVE01_MAPLE_GROVE04	3,964	1	Project	Resiliency - MIEJ Hardening	Flint	Customer-outage-minutes avoided	179,639
41		**Vulnerable Communities Total**	**40,000**						
42	Resiliency	MOBILE 27	3,045	1	Project	Resiliency - Fractionalization	Statewide	Reliability - outage minutes avoided	-
43		PRESCOTT	1,909	1	Project	Resiliency - Fractionalization	Ogemaw	Reliability - outage minutes avoided	1,394,280
44		CADMUS	2,261	0	Project	Resiliency - Fractionalization	Lenawee	Reliability - outage minutes avoided	-
45		COTTAGE GROVE	6,591	1	Project	Resiliency - Fractionalization	Bay	Reliability - outage minutes avoided	3,491,640
46		KENT CITY	585	0	Project	Resiliency - Fractionalization	Kent	Reliability - outage minutes avoided	-
47		WOLF LAKE	906	0	Project	Resiliency - Fractionalization	Van Buren	Reliability - outage minutes avoided	-
48		EAGLE	1,850	1	Project	Resiliency - Fractionalization	Ottawa	Reliability - outage minutes avoided	249,309
49		EAST TAWAS	570	1	Project	Resiliency - Fractionalization	Iosco Co.	Reliability - outage minutes avoided	194,455
50		**Fractionalization Total**	**17,716**						
40		Wildfire Risk Mitigation - Covered Conductor	1,095	3.1	Miles	Wildfire Risk Mitigation	Statewide	Reduction in expected annual loss ($000)	985
41		Wildfire Risk Mitigation - Non Expulsion Fuses	740	493	Fuses	Wildfire Risk Mitigation	Statewide	Reduction in expected annual loss ($000)	1,099
42		**Resiliency Total**	**78,751**						

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Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	DARE VAN BUREN_RUSH CREEK LCP 0687	10	1	Project	Overloaded Equipment Upgrades	NORTH BUREN	Overload Failure Reduction; Customers	25
2	LVD Lines Capacity	DARE WARNER-BURCHETT 312 ISOLATOR PART 1	312	1	Project	Overloaded Equipment Upgrades	NORTH BURCHETT	Overload Failure Reduction; Customers	144
3	LVD Lines Capacity	DARE WATKINS_HAMILTON LCP 575	410	1	Project	Overloaded Equipment Upgrades	WATKINS	Overload Failure Reduction; Customers	395
4	LVD Lines Capacity	DARE BELL ROAD/ALBEE LCP 989	743	1	Project	Overloaded Equipment Upgrades	BURT	Overload Failure Reduction; Customers	1276
5	LVD Lines Capacity	DARE EIGHT PT LUDNGTON LCP 751 PART 1	1128	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	147
6	LVD Lines Capacity	DARE LEVELY_ALLBRIGHT LCP 239	10	1	Project	Overloaded Equipment Upgrades	TOBACCO	Overload Failure Reduction; Customers	54
7	LVD Lines Capacity	DARE LEVELY_ALLBRIGHT LCP 665	541	1	Project	Overloaded Equipment Upgrades	GRASS LAKE	Overload Failure Reduction; Customers	669
8	LVD Lines Capacity	DARE AGNEW_WEYBURN LCP 207	3	1	Project	Overloaded Equipment Upgrades	OLIVE	Overload Failure Reduction; Customers	89
9	LVD Lines Capacity	DARE AGNEW_WEYBURN LCP 307	47	1	Project	Overloaded Equipment Upgrades	GRAND HAVEN	Overload Failure Reduction; Customers	1399
10	LVD Lines Capacity	DARE AGNEW_WEYBURN LCP 309	3	1	Project	Overloaded Equipment Upgrades	GRAND HAVEN	Overload Failure Reduction; Customers	125
11	LVD Lines Capacity	DARE BLUE STAR/PIER COVE LCP 613	767	1	Project	Overloaded Equipment Upgrades	GANGES	Overload Failure Reduction; Customers	131
12	LVD Lines Capacity	DARE COLON_PALMER LCP 536	79	1	Project	Overloaded Equipment Upgrades	COLON	Overload Failure Reduction; Customers	105
13	LVD Lines Capacity	DARE ENGLISHVILLE/ENGLISHVILLE PH EXT	590	1	Project	Overloaded Equipment Upgrades	SPARTA	Overload Failure Reduction; Customers	157
14	LVD Lines Capacity	DARE FLETCHER_ODEN LCP 0067	37	1	Project	Overloaded Equipment Upgrades	ALANSON	Overload Failure Reduction; Customers	133
15	LVD Lines Capacity	DARE GRASS_LAKE 25 LCP 311	50	1	Project	Overloaded Equipment Upgrades	GRASS LAKE	Overload Failure Reduction; Customers	80
16	LVD Lines Capacity	DARE MONTEREY_30TH STREET LCP 818	10	1	Project	Overloaded Equipment Upgrades	BURNIPS	Overload Failure Reduction; Customers	142
17	LVD Lines Capacity	DARE N MUSKEGON DALTON LCP 285	310	1	Project	Overloaded Equipment Upgrades	MUSKEGON	Overload Failure Reduction; Customers	293
18	LVD Lines Capacity	DARE NORTH MUSKEGON_SANITARIUM LCP 524	1	1	Project	Overloaded Equipment Upgrades	MUSKEGON	Overload Failure Reduction; Customers	411
19	LVD Lines Capacity	DARE NORTH PARK_COIT LCP 302 CONDUCTOR	552	1	Project	Overloaded Equipment Upgrades	BELMONT	Overload Failure Reduction; Customers	187
20	LVD Lines Capacity	DARE ONEKAMA_BEAR LAKE LCP 710	477	1	Project	Overloaded Equipment Upgrades	BEAR LAKE	Overload Failure Reduction; Customers	309
21	LVD Lines Capacity	DARE PEACH RIDGE/KENOWA CONV PT5A	916	1	Project	Overloaded Equipment Upgrades	SPARTA	Overload Failure Reduction; Customers	153
22	LVD Lines Capacity	DARE PORT CALCITE_WOODWARD LCP 0487 REG	40	1	Project	Overloaded Equipment Upgrades	SAGINAW	Overload Failure Reduction; Customers	1124
23	LVD Lines Capacity	DARE ROSEWOOD_LAMPLIGHTER LCP 0991	654	1	Project	Overloaded Equipment Upgrades	JENISON	Overload Failure Reduction; Customers	2863
24	LVD Lines Capacity	DARE WESTERN AVENUE_LAKESIDE LCP 232	654	1	Project	Overloaded Equipment Upgrades	LAKETON	Overload Failure Reduction; Customers	308
25	LVD Lines Capacity	DARE HASTINGS_HANOVER LCP 7302	2	1	Project	Overloaded Equipment Upgrades	HASTINGS	Overload Failure Reduction; Customers	13
26	LVD Lines Capacity	DARE FREELAND_FREELAND LCP 661	283	1	Project	Overloaded Equipment Upgrades	TITTABAWASSEE	Overload Failure Reduction; Customers	122
27	LVD Lines Capacity	DARE PALO SUBSTATION LVD REBUILD	1802	1	Project	Overloaded Equipment Upgrades	RONALD	Overload Failure Reduction; Customers	934
28	LVD Lines Capacity	DARE VIPOND_BROOK LCP 0170	3	1	Project	Overloaded Equipment Upgrades	RAPID RIVER	Overload Failure Reduction; Customers	48
29	LVD Lines Capacity	DARE APPLE_CHATTERSON ROAD LCP 595	19	1	Project	Overloaded Equipment Upgrades	EGELSTON	Overload Failure Reduction; Customers	155
30	LVD Lines Capacity	DARE OTTAWA BEACH_LAKEWOOD LCP 568	8	1	Project	Overloaded Equipment Upgrades	MACATAWA	Overload Failure Reduction; Customers	96
31	LVD Lines Capacity	DARE MICHIGAN CENTER_PAGE LCP 415	150	1	Project	Overloaded Equipment Upgrades	MICHIGAN CENTER	Overload Failure Reduction; Customers	160
32	LVD Lines Capacity	DARE CASCO_BLUFF LCP 039	310	1	Project	Overloaded Equipment Upgrades	CASCO	Overload Failure Reduction; Customers	70
33	LVD Lines Capacity	DARE RODNEY_RODNEY LCP 705	32	1	Project	Overloaded Equipment Upgrades	CANADIAN LAKE	Overload Failure Reduction; Customers	136
34	LVD Lines Capacity	DARE NEW RICHMND_HOLLAND RENDER lcp 003	8	1	Project	Overloaded Equipment Upgrades	CHESHIRE	Overload Failure Reduction; Customers	1
35	LVD Lines Capacity	DARE CHESTER_MORRELL LCP 071	7	1	Project	Overloaded Equipment Upgrades	MULLIKEN	Overload Failure Reduction; Customers	35
36	LVD Lines Capacity	DARE RANKIN_GREEN VALLEY LCP 288	8	1	Project	Overloaded Equipment Upgrades	MUNDY	Overload Failure Reduction; Customers	420
37	LVD Lines Capacity	DARE SWAN CREEK_MINING	909	1	Project	Overloaded Equipment Upgrades	SWAN	Overload Failure Reduction; Customers	180
38	LVD Lines Capacity	DARE PORTAGE SHAVER ROAD 917	319	1	Project	Overloaded Equipment Upgrades	PORTAGE	Overload Failure Reduction; Customers	1328
39	LVD Lines Capacity	DARE BEHNKE_RIVER ROAD OH	336	1	Project	Overloaded Equipment Upgrades	COLDWATER	Overload Failure Reduction; Customers	125
40	LVD Lines Capacity	DARE LOVEJOY-DEERFIELD PHI - PT. 1	1061	1	Project	Overloaded Equipment Upgrades	DEERFIELD	Overload Failure Reduction; Customers	150
41	LVD Lines Capacity	DARE NAPOLEON/NORVELL-980-AUSTIN W/O B	732	1	Project	Overloaded Equipment Upgrades	NAPOLEON	Overload Failure Reduction; Customers	42
42	LVD Lines Capacity	DARE PRICE ROAD/PRICE LCP153 LOC 1-21	675	1	Project	Overloaded Equipment Upgrades	LINCOLN	Overload Failure Reduction; Customers	249
43	LVD Lines Capacity	DARE BELDING COOKS CORNER LCP 489	154	1	Project	Overloaded Equipment Upgrades	BELDING	Overload Failure Reduction; Customers	152
44	LVD Lines Capacity	DARE HARRISON STOCKWELL LCP 074	333	1	Project	Overloaded Equipment Upgrades	HARRISON	Overload Failure Reduction; Customers	222
45	LVD Lines Capacity	DARE DOBSON RD-HALF MOON-LCP 375	111	1	Project	Overloaded Equipment Upgrades	SCIPIO	Overload Failure Reduction; Customers	50
46	LVD Lines Capacity	DARE LEVELY_ALBRIGHT LCP 250	181	1	Project	Overloaded Equipment Upgrades	TOBACCO	Overload Failure Reduction; Customers	254
47	LVD Lines Capacity	DARE SURREY SURREY LCP 708 PART 1	625	1	Project	Overloaded Equipment Upgrades	NORTH SURREY	Overload Failure Reduction; Customers	251
48	LVD Lines Capacity	DARE PORTAGE SHAVER RD OAKLAND RECOND	92	1	Project	Overloaded Equipment Upgrades	PORTAGE	Overload Failure Reduction; Customers	282
49	LVD Lines Capacity	DARE CONVIS CONVIS LCP 369	21	1	Project	Overloaded Equipment Upgrades	BATTLE CREEK	Overload Failure Reduction; Customers	40
50	LVD Lines Capacity	DARE MAPLE CITY/CEDAR LCP 060	114	1	Project	Overloaded Equipment Upgrades	MAPLE CITY	Overload Failure Reduction; Customers	127
51	LVD Lines Capacity	DARE PARNALL PARNALL SUB	370	1	Project	Overloaded Equipment Upgrades	JACKSON	Overload Failure Reduction; Customers	1895
52		**LVD Lines Capacity Subtotal**	**17,010**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2028
($000)

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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	DARE MARKER LAKE_KYSER RD LCP 590 A	535	1	Project	Overloaded Equipment Upgrades	LOWELL	Overload Failure Reduction; Customers	342
2		DARE LITCHFIELD_QUAKER LAKE LCP 522	26	1	Project	Overloaded Equipment Upgrades	BUTLER	Overload Failure Reduction; Customers	31
3		DARE DEER LK/CRANBERRY LCP 268 LOC9-16	993	1	Project	Overloaded Equipment Upgrades	HARRISON	Overload Failure Reduction; Customers	318
4		DARE HANNAH_HANNAH LCP 337 PART 1	434	1	Project	Overloaded Equipment Upgrades	WEXFORD	Overload Failure Reduction; Customers	292
5		DARE BIL-MAR_POLK LCP 527	1019	1	Project	Overloaded Equipment Upgrades	BLENDON	Overload Failure Reduction; Customers	135
6		DARE FINE LAKE - DOWLING	111	1	Project	Overloaded Equipment Upgrades	JOHNSTON	Overload Failure Reduction; Customers	471
7		DARE KINGSLEY_WALTON LCP 690	86	1	Project	Overloaded Equipment Upgrades	KINGSLEY	Overload Failure Reduction; Customers	86
8		DARE MAPLE CITY_CEDAR LCP 203	3	1	Project	Overloaded Equipment Upgrades	KASSON	Overload Failure Reduction; Customers	1
9		DARE DIMONDALE_M-99 LCP 778Z	39	1	Project	Overloaded Equipment Upgrades	DIMONDALE	Overload Failure Reduction; Customers	502
10		DARE MONA LAKE_AIRPORT LCP 0564	1	1	Project	Overloaded Equipment Upgrades	FRUITPORT	Overload Failure Reduction; Customers	517
11		DARE FRUITPORT_JUDSON ROAD LCP 763	205	1	Project	Overloaded Equipment Upgrades	FRUITPORT	Overload Failure Reduction; Customers	827
12		DARE FRUITPORT_JUDSON ROAD LCP 3069	1	1	Project	Overloaded Equipment Upgrades	FRUITPORT	Overload Failure Reduction; Customers	30
13		DARE BAYBERRY_KOSTER LCP 0148	2	1	Project	Overloaded Equipment Upgrades	BYRON	Overload Failure Reduction; Customers	54
14		DARE BRETON_TOWERS LCP 0555	3	1	Project	Overloaded Equipment Upgrades	KENTWOOD	Overload Failure Reduction; Customers	2596
15		DARE HAGER PARK_HAGER PARK LCP 0557	8	1	Project	Overloaded Equipment Upgrades	GEORGETOWN	Overload Failure Reduction; Customers	271
16		DARE CHICAGO_PINEBROOK LCP 0357	4	1	Project	Overloaded Equipment Upgrades	GEORGETOWN	Overload Failure Reduction; Customers	575
17		DARE ROCKFORD_SUMMIT LCP 043 ISOLATOR	15	1	Project	Overloaded Equipment Upgrades	ROCKFORD	Overload Failure Reduction; Customers	67
18		DARE ROCKFORD_SUMMIT LCP 171 ISOLATOR	26	1	Project	Overloaded Equipment Upgrades	ROCKFORD	Overload Failure Reduction; Customers	1
19		DARE PARAMOUNT_NORTHLAND FARMS LCP-742	127	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	1842
20		DARE BELSAY_BELSAY LCP 133	12	1	Project	Overloaded Equipment Upgrades	BURTON	Overload Failure Reduction; Customers	334
21		DARE HOGAN ROAD_HOISINGTON LCP 308	25	1	Project	Overloaded Equipment Upgrades	FENTON	Overload Failure Reduction; Customers	155
22		DARE KEARSLEY_COVERT ROAD LCP 793	18	1	Project	Overloaded Equipment Upgrades	BURTON	Overload Failure Reduction; Customers	129
23		DARE HESPERIA RURAL LCP 325 PART 5	941	1	Project	Overloaded Equipment Upgrades	BEAVER	Overload Failure Reduction; Customers	126
24		DARE GUN LAKE_ENGLAND LCP 0319J	2	1	Project	Overloaded Equipment Upgrades	YANKEE SPRINGS	Overload Failure Reduction; Customers	629
25		DARE BATH_BATH LCP 0206	4	1	Project	Overloaded Equipment Upgrades	BATH	Overload Failure Reduction; Customers	430
26		DARE BLUE WATER_SCOTT ROAD LCP 0393	2	1	Project	Overloaded Equipment Upgrades	EUREKA	Overload Failure Reduction; Customers	83
27		DARE CHARLOTTE_FOOTE STREET LCP 856	28	1	Project	Overloaded Equipment Upgrades	CARMEL	Overload Failure Reduction; Customers	84
28		DARE CHESTER_CARLISLE LCP 738	13	1	Project	Overloaded Equipment Upgrades	KALAMO	Overload Failure Reduction; Customers	90
29		DARE COCHRAN_KALAMO LCP 463	27	1	Project	Overloaded Equipment Upgrades	CARMEL	Overload Failure Reduction; Customers	165
30		DARE LOOMIS_LOOMIS ROAD LCP 7002	8	1	Project	Overloaded Equipment Upgrades	OLIVE	Overload Failure Reduction; Customers	483
31		DARE LOOMIS_TAFT ROAD LCP 0165	35	1	Project	Overloaded Equipment Upgrades	BINGHAM	Overload Failure Reduction; Customers	466
32		DARE MASON_BUSINESS LCP 0162	3	1	Project	Overloaded Equipment Upgrades	EDEN	Overload Failure Reduction; Customers	377
33		DARE MERIDIAN_LAKE LANSING LCP 0644	3	1	Project	Overloaded Equipment Upgrades	HASLETT	Overload Failure Reduction; Customers	138
34		DARE POTTERVILLE_POTTERVILLE LCP 103	13	1	Project	Overloaded Equipment Upgrades	BENTON	Overload Failure Reduction; Customers	904
35		DARE SUNFIELD_MULLIKEN LCP 583	14	1	Project	Overloaded Equipment Upgrades	MULLIKEN	Overload Failure Reduction; Customers	70
36		DARE UPTON_MT HOPE LCP 722	13	1	Project	Overloaded Equipment Upgrades	DELTA	Overload Failure Reduction; Customers	100
37		DARE VAN ATTA_LEGG PARK LCP 0004	17	1	Project	Overloaded Equipment Upgrades	HASLETT	Overload Failure Reduction; Customers	991
38		DARE WHITTUM_KINNEVILLE LCP 248	5	1	Project	Overloaded Equipment Upgrades	EATON RAPIDS	Overload Failure Reduction; Customers	54
39		DARE WHITTUM_ROYSTON LCP 277	5	1	Project	Overloaded Equipment Upgrades	BROOKFIELD	Overload Failure Reduction; Customers	80
40		DARE DURAND_GAINES Recloser Pittsburg Rd	23	1	Project	Overloaded Equipment Upgrades	DURAND	Overload Failure Reduction; Customers	584
41		DARE LOVEJOY_BRADEN LCP 906	10	1	Project	Overloaded Equipment Upgrades	BURNS	Overload Failure Reduction; Customers	123
42		DARE OWOSSO_STEWART LCP 734	11	1	Project	Overloaded Equipment Upgrades	CALEDONIA	Overload Failure Reduction; Customers	795
43		DARE CRAWFORD_WINN LCP 0355	6	1	Project	Overloaded Equipment Upgrades	MOUNT PLEASANT	Overload Failure Reduction; Customers	304
44		DARE LEITH STREET_WESTERN ROAD LCP 011	334	1	Project	Overloaded Equipment Upgrades	GENESEE	Overload Failure Reduction; Customers	911
45		DARE MARTIN_SHELBYVILLE LCP 227	33	1	Project	Overloaded Equipment Upgrades	WATSON	Overload Failure Reduction; Customers	439
46		DARE TITUS LAKE_TENTH STREET LCP 0625	1	1	Project	Overloaded Equipment Upgrades	MARTIN	Overload Failure Reduction; Customers	1
47		DARE WAYLAND_WAYLAND LCP 877	111	1	Project	Overloaded Equipment Upgrades	BRADLEY	Overload Failure Reduction; Customers	171
48		DARE WOODLAND_BARNUM LCP 0028	8	1	Project	Overloaded Equipment Upgrades	WOODLAND	Overload Failure Reduction; Customers	77
49		DARE VANDERCOOK LAKE/VANDERCOOK LAKE	570	1	Project	Overloaded Equipment Upgrades	SUMMIT	Overload Failure Reduction; Customers	152
50		DARE DRAKE ROAD_WURZBURG LCP 513	28	1	Project	Overloaded Equipment Upgrades	OSHTEMO	Overload Failure Reduction; Customers	473
51		DARE KALARAMA_ROMENCE LCP 608	25	1	Project	Overloaded Equipment Upgrades	PORTAGE	Overload Failure Reduction; Customers	457
52		DARE OSHTEMO_ALMENA LCP 422	47	1	Project	Overloaded Equipment Upgrades	OSHTEMO	Overload Failure Reduction; Customers	438
53		DARE PHILLIPS_ALCOTT LCP SUB	193	1	Project	Overloaded Equipment Upgrades	KALAMAZOO	Overload Failure Reduction; Customers	1546
54		DARE RIX ROAD_UNDERPASS LCP 931	61	1	Project	Overloaded Equipment Upgrades	OSHTEMO	Overload Failure Reduction; Customers	887
55		**LVD Lines Capacity Subtotal**	**6,289**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2028
($000)

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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	DARE WARNER_MILO LCP 0658	14	1	Project	Overloaded Equipment Upgrades	BARRY	Overload Failure Reduction; Customers	237
2		DARE DEXTER TRAIL_DANSVILLE LCP 5319	209	1	Project	Overloaded Equipment Upgrades	DANSVILLE	Overload Failure Reduction; Customers	85
3		DARE DIMONDALE_M-99 LCP 724	58	1	Project	Overloaded Equipment Upgrades	DIMONDALE	Overload Failure Reduction; Customers	1051
4		DARE POTTERVILLE_M-78 LCP 565	1588	1	Project	Overloaded Equipment Upgrades	DIMONDALE	Overload Failure Reduction; Customers	81
5		DARE ELSIE_Carland Reconductor	1157	1	Project	Overloaded Equipment Upgrades	DUPLAIN	Overload Failure Reduction; Customers	580
6		DARE CHESANING/CHESANING LCP 360	14	1	Project	Overloaded Equipment Upgrades	CHESANING	Overload Failure Reduction; Customers	133
7		DARE FOREMAN_CUMBERLAND LCP 510	86	1	Project	Overloaded Equipment Upgrades	ALTO	Overload Failure Reduction; Customers	96
8		DARE STANDALE_STANDALE LCP 674	20	1	Project	Overloaded Equipment Upgrades	GRAND RAPIDS	Overload Failure Reduction; Customers	882
9		DARE KENTWOOD_PARIS PARK LCP 227	37	1	Project	Overloaded Equipment Upgrades	KENTWOOD	Overload Failure Reduction; Customers	1234
10		DARE PARAMOUNT_BIRD LCP SUB	32	1	Project	Overloaded Equipment Upgrades	BELMONT	Overload Failure Reduction; Customers	1371
11		DARE SURREY SURREY LCP 680	250	1	Project	Overloaded Equipment Upgrades	SURREY	Overload Failure Reduction; Customers	162
12		DARE BEADLE_CREST SUB	290	1	Project	Overloaded Equipment Upgrades	BATTLE CREEK	Overload Failure Reduction; Customers	285
13		DARE FRUITPORT_JUDSON ROAD 3rd ave	752	1	Project	Overloaded Equipment Upgrades	FRUITPORT	Overload Failure Reduction; Customers	1000
14		DARE NIAGARA/ADAMS LCP 222	563	1	Project	Overloaded Equipment Upgrades	SAGINAW	Overload Failure Reduction; Customers	1271
15		DARE MARKEY CARRICK LCP 900	485	1	Project	Overloaded Equipment Upgrades	GERRISH	Overload Failure Reduction; Customers	1795
16		DARE BEECHER_ANDERSON LCP SUB	483	1	Project	Overloaded Equipment Upgrades	ADRIAN	Overload Failure Reduction; Customers	1052
17		DARE HAWTHORNE_MINNEMA LCP 446	14	1	Project	Overloaded Equipment Upgrades	ALPINE	Overload Failure Reduction; Customers	308
18		DARE KENT CITY_CASNOVIA LCP 854 ISOLATOR	68	1	Project	Overloaded Equipment Upgrades	CASNOVIA	Overload Failure Reduction; Customers	65
19		DARE ROGUE RIVER_ROGUE RIVER LCP 472	52	1	Project	Overloaded Equipment Upgrades	BELMONT	Overload Failure Reduction; Customers	93
20		DARE LEVELY_STURGEON LCP 275	595	1	Project	Overloaded Equipment Upgrades	HOPE	Overload Failure Reduction; Customers	564
21		DARE GREENWOOD_INDIAN LAKE LCP 765	121	1	Project	Overloaded Equipment Upgrades	CLEMENT	Overload Failure Reduction; Customers	66
22		DARE ALDEN_CLAM LCP 8070	4	1	Project	Overloaded Equipment Upgrades	ALDEN	Overload Failure Reduction; Customers	184
23		DARE GREENWOOD_M-33 LCP 672	24	1	Project	Overloaded Equipment Upgrades	MILLS	Overload Failure Reduction; Customers	540
24		DARE FERRIS STREET_FORREST PARK LCP 306	4	1	Project	Overloaded Equipment Upgrades	GRAND HAVEN	Overload Failure Reduction; Customers	125
25		DARE RIVERDALE_SUMNER LCP 114	17	1	Project	Overloaded Equipment Upgrades	ELM HALL	Overload Failure Reduction; Customers	34
26		DARE WITHEY LAKE_PETTIT LCP 0014	201	1	Project	Overloaded Equipment Upgrades	HILL	Overload Failure Reduction; Customers	271
27		DARE WITHEY LAKE_PETTIT LCP 0004	36	1	Project	Overloaded Equipment Upgrades	LOGAN	Overload Failure Reduction; Customers	357
28		DARE ALLENDALE_BLENDON LCP 542	60	1	Project	Overloaded Equipment Upgrades	ALLENDALE	Overload Failure Reduction; Customers	67
29		DARE RYNO_MAPES LCP 0007	23	1	Project	Overloaded Equipment Upgrades	BIG CREEK	Overload Failure Reduction; Customers	716
30		DARE GREENWOOD_M-33 LCP 983	325	1	Project	Overloaded Equipment Upgrades	HORTON	Overload Failure Reduction; Customers	1300
31		DARE CARY ROAD_LAKE COLUMBIA LCP 781	377	1	Project	Overloaded Equipment Upgrades	BROOKLYN	Overload Failure Reduction; Customers	100
32		DARE COTTAGE GROVE_HURON LCP 859	59	1	Project	Overloaded Equipment Upgrades	FRASER	Overload Failure Reduction; Customers	254
33		DARE NOBLE_DUBY LCP 9299	66	1	Project	Overloaded Equipment Upgrades	WHITNEY	Overload Failure Reduction; Customers	288
34		DARE HUBBARD LAKE_HUBBARD LAKE LCP 600	248	1	Project	Overloaded Equipment Upgrades	BARTON CITY	Overload Failure Reduction; Customers	323
35		DARE RANGER LAKE/KOKOSING LCP 582	16	1	Project	Overloaded Equipment Upgrades	GOODAR	Overload Failure Reduction; Customers	197
36		DARE SPRUCE ROAD_BLACK RIVER LCP 741	743	1	Project	Overloaded Equipment Upgrades	HAYNES	Overload Failure Reduction; Customers	382
37		DARE SANDERSON_M-57 LCP 184	34	1	Project	Overloaded Equipment Upgrades	FAIRPLAINS	Overload Failure Reduction; Customers	64
38		DARE STURGEON_SAGINAW ROAD LCP 855	59	1	Project	Overloaded Equipment Upgrades	MIDLAND	Overload Failure Reduction; Customers	60
39		DARE ALCONA DAM_CURTISVILLE LCP 779	410	1	Project	Overloaded Equipment Upgrades	CURTIS	Overload Failure Reduction; Customers	384
40		DARE SPRUCE ROAD_BLACK RIVER LCP 696	80	1	Project	Overloaded Equipment Upgrades	ALCONA	Overload Failure Reduction; Customers	547
41		DARE NOBLE_WHITNEY LCP 553	44	1	Project	Overloaded Equipment Upgrades	WHITNEY	Overload Failure Reduction; Customers	181
42		DARE HUBBARD LAKE_MILLER ROAD LCP 655	22	1	Project	Overloaded Equipment Upgrades	BARTON CITY	Overload Failure Reduction; Customers	231
43		DARE CEDAR LAKE_KINGS CORNER LCP 638	962	1	Project	Overloaded Equipment Upgrades	OSCODA	Overload Failure Reduction; Customers	880
44		DARE CEDAR LAKE_KINGS CORNER LCP 540	62	1	Project	Overloaded Equipment Upgrades	MIKADO	Overload Failure Reduction; Customers	290
45		DARE RYNO_MORENCI LCP 0238	982	1	Project	Overloaded Equipment Upgrades	BIG CREEK	Overload Failure Reduction; Customers	665
46		DARE BASS LAKE_KISTLER LCP 3863	17	1	Project	Overloaded Equipment Upgrades	SUMMIT	Overload Failure Reduction; Customers	370
47		DARE PELLSTON_DISTRIBUTION LCP 243	28	1	Project	Overloaded Equipment Upgrades	BURT	Overload Failure Reduction; Customers	173
48		DARE NAPOLEON_NORVELL LCP 959	2378	1	Project	Overloaded Equipment Upgrades	NORVELL	Overload Failure Reduction; Customers	858
49		DARE CASCO_HAWKHEAD LCP 466	1127	1	Project	Overloaded Equipment Upgrades	GANGES	Overload Failure Reduction; Customers	152
50		DARE LAKE CITY_STITTSVILLE LCP 357	9	1	Project	Overloaded Equipment Upgrades	NORWICH	Overload Failure Reduction; Customers	223
51		DARE HIGH BRIDGE_CREAMERY LCP 892	12	1	Project	Overloaded Equipment Upgrades	BRETHREN	Overload Failure Reduction; Customers	189
52		DARE PATTERSON_PATTERSON LCP 979	2	1	Project	Overloaded Equipment Upgrades	BANGOR	Overload Failure Reduction; Customers	140
53		DARE RIX ROAD_UNDERPASS LCP 931	89	1	Project	Overloaded Equipment Upgrades	OSHTEMO	Overload Failure Reduction; Customers	887
54		DARE SAUGATUCK_DOUGLAS LCP 119	797	1	Project	Overloaded Equipment Upgrades	DOUGLAS	Overload Failure Reduction; Customers	967
55		DARE BLUE STAR_GANGES LCP 892	454	1	Project	Overloaded Equipment Upgrades	GANGES	Overload Failure Reduction; Customers	92
56		**LVD Lines Capacity Subtotal**	**16,660**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
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($000)

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Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	LVD Lines Capacity	DARE BASS LAKE_CARTER LCP 3884	476	1	Project	Overloaded Equipment Upgrades	PENTWATER	Overload Failure Reduction; Customers	160
2		DARE OSCODA_BUTLER HEIGHTS LCP 251	71	1	Project	Overloaded Equipment Upgrades	AU SABLE	Overload Failure Reduction; Customers	876
3		DARE PEARLINE_COPPER BEACH LCP 0490	79	1	Project	Overloaded Equipment Upgrades	ALLENDALE	Overload Failure Reduction; Customers	2789
4		DARE HAMILTON_HAMILTON LCP 241	1,225	1	Project	Overloaded Equipment Upgrades	HAMILTON	Overload Failure Reduction; Customers	462
5		DARE SAUGATUCK_DOUGLAS LCP sub	885	1	Project	Overloaded Equipment Upgrades	DOUGLAS	Overload Failure Reduction; Customers	2227
6		DARE BAGLEY_FREDERIC LCP 5400	4	1	Project	Overloaded Equipment Upgrades	BAGLEY	Overload Failure Reduction; Customers	1268
7		DARE COOPERSVILLE_CONKLIN LCP 453	4	1	Project	Overloaded Equipment Upgrades	COOPERSVILLE	Overload Failure Reduction; Customers	1335
8		DARE LAKE CITY_MOREY LCP 5248	21	1	Project	Overloaded Equipment Upgrades	CALDWELL	Overload Failure Reduction; Customers	220
9		DARE AGNEW_WEYBURN LCP 615	64	1	Project	Overloaded Equipment Upgrades	PORT SHELDON	Overload Failure Reduction; Customers	1000
10		DARE FLETCHER_ODEN LCP 0522	12	1	Project	Overloaded Equipment Upgrades	ALANSON	Overload Failure Reduction; Customers	1063
11		DARE OSHTEMO_ALMENA LCP 422	68	1	Project	Overloaded Equipment Upgrades	OSHTEMO	Overload Failure Reduction; Customers	438
12		DARE HURON_MONITOR LCP 230	56	1	Project	Overloaded Equipment Upgrades	KAWKAWLIN	Overload Failure Reduction; Customers	573
13		DARE ARTHUR_BERLIN LCP 369	4	1	Project	Overloaded Equipment Upgrades	ALLENDALE	Overload Failure Reduction; Customers	55
14		DARE FERRIS STREET_FORREST PARK LCP 704	8	1	Project	Overloaded Equipment Upgrades	GRAND HAVEN	Overload Failure Reduction; Customers	75
15		DARE SAVIDGE_BOOM ROAD LCP 0077	36	1	Project	Overloaded Equipment Upgrades	FERRYSBURG	Overload Failure Reduction; Customers	600
16		DARE CRAWFORD_WINN LCP 0355	9	1	Project	Overloaded Equipment Upgrades	MOUNT PLEASANT	Overload Failure Reduction; Customers	304
17		DARE BATES_ACME LCP 800	4	1	Project	Overloaded Equipment Upgrades	ACME	Overload Failure Reduction; Customers	77
18		DARE WIRTZ ROAD_WILDWOOD LCP 532	133	1	Project	Overloaded Equipment Upgrades	SECORD	Overload Failure Reduction; Customers	183
19		DARE WEBB ROAD_PLAINFIELD LCP 480	794	1	Project	Overloaded Equipment Upgrades	HALE	Overload Failure Reduction; Customers	214
20		DARE GLEN LAKE_BURDICKVILLE LCP 683	57	1	Project	Overloaded Equipment Upgrades	CLEVELAND	Overload Failure Reduction; Customers	341
21		DARE REA ROAD_EAST RIVER SUB	101	1	Project	Overloaded Equipment Upgrades	OSCODA	Overload Failure Reduction; Customers	75
22		DARE SHEPHERD_FOREST HILL LCP 183	167	1	Project	Overloaded Equipment Upgrades	PINE RIVER	Overload Failure Reduction; Customers	880
23		DARE MARKEY_CARRICK LCP 721	14	1	Project	Overloaded Equipment Upgrades	GERRISH	Overload Failure Reduction; Customers	1011
24		DARE HANNAH_HANNAH LCP 9027	11	1	Project	Overloaded Equipment Upgrades	BUCKLEY	Overload Failure Reduction; Customers	244
25		DARE BASS LAKE_CARTER LCP 113	13	1	Project	Overloaded Equipment Upgrades	SUMMIT	Overload Failure Reduction; Customers	148
26		DARE CHESANING/PEET LCP 038	6	1	Project	Overloaded Equipment Upgrades	MAPLE GROVE	Overload Failure Reduction; Customers	245
27		DARE SMALLWOOD DAM_DISTRIBUTION LCP 856	20	1	Project	Overloaded Equipment Upgrades	BUCKEYE	Overload Failure Reduction; Customers	644
28		DARE CASCO_HAWKHEAD LCP 460	6	1	Project	Overloaded Equipment Upgrades	GANGES	Overload Failure Reduction; Customers	17
29		DARE GROVER_TRIANGLE LCP 524	8	1	Project	Overloaded Equipment Upgrades	EMERSON	Overload Failure Reduction; Customers	28
30		DARE INTERLOCHEN_ART CAMP LCP 797	6	1	Project	Overloaded Equipment Upgrades	GREEN LAKE	Overload Failure Reduction; Customers	1
31		DARE HAWTHORNE_MINNEMA LCP 041	34	1	Project	Overloaded Equipment Upgrades	ALPINE	Overload Failure Reduction; Customers	406
32		DARE HANOVER_HORTON LCP 579	2	1	Project	Overloaded Equipment Upgrades	HANOVER	Overload Failure Reduction; Customers	34
33		DARE SURREY_MAIN STREET LCP 421	1,164	1	Project	Overloaded Equipment Upgrades	VERNON	Overload Failure Reduction; Customers	102
34		DARE PELLSTON_BURT LAKE LCP 6002	4	1	Project	Overloaded Equipment Upgrades	BURT	Overload Failure Reduction; Customers	16
35		DARE FREELAND_FREELAND LCP 0620	89	1	Project	Overloaded Equipment Upgrades	FREELAND	Overload Failure Reduction; Customers	178
36		DARE MARKEY_MONTYVILLE LCP 365	25	1	Project	Overloaded Equipment Upgrades	LAKE	Overload Failure Reduction; Customers	260
37		DARE KINDERHOOK_GILEAD LCP 365	51	1	Project	Overloaded Equipment Upgrades	KINDERHOOK	Overload Failure Reduction; Customers	341
38		DARE CHEBOYGAN_ALVERNO LCP 878	40	1	Project	Overloaded Equipment Upgrades	INVERNESS	Overload Failure Reduction; Customers	1026
39		DARE FOX FARM_LINKE LCP 209	59	1	Project	Overloaded Equipment Upgrades	FILER	Overload Failure Reduction; Customers	551
40		DARE O-AT-KA_PINE GROVE LCP 730	2	1	Project	Overloaded Equipment Upgrades	ACME	Overload Failure Reduction; Customers	5
41		DARE TITUS LAKE_TENTH STREET LCP 0625	2	1	Project	Overloaded Equipment Upgrades	MARTIN	Overload Failure Reduction; Customers	1
42		DARE WAYLAND_WAYLAND LCP 0877	2	1	Project	Overloaded Equipment Upgrades	BRADLEY	Overload Failure Reduction; Customers	171
43		DARE MANTON_GILBERT LCP 368	4	1	Project	Overloaded Equipment Upgrades	LIBERTY	Overload Failure Reduction; Customers	125
44		DARE NUNICA_WILSON_0025	4	1	Project	Overloaded Equipment Upgrades	CROCKERY	Overload Failure Reduction; Customers	20
45	LVD Lines Capacity	DARE PEACH RIDGE/BALLARD CONV PT5	493	1	Project	Sub Capacity-associated Line Work	GRAND RAPIDS	Overload Failure Reduction; Customers	230
46		DARE VALENTINE SUB	4,038	1	Project	Sub Capacity-associated Line Work	PAVILION	Overload Failure Reduction; Customers	802
47		DARE TAMARACK-LAKEVIEW LOC 1-23	1,032	1	Project	Sub Capacity-associated Line Work	LAKEVIEW	Overload Failure Reduction; Customers	26
48		DARE MARKEY_FOREST ESTATES LCP SUB	1,814	1	Project	Sub Capacity-associated Line Work	MARKEY	Overload Failure Reduction; Customers	2408
49		DARE MERCURY SUB EXITS AND LVD WORK	306	1	Project	Sub Capacity-associated Line Work	BATTLE CREEK	Overload Failure Reduction; Customers	279
50		**LVD Lines Capacity Subtotal**	**13,526**						
51		**LVD Lines Capacity Total**	**53,485**						

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year LVD Project List
For the Test Year 12 Months Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-168 (JMP-2)
Page: 19 of 19
Witness: JMPartlan
Date: June 2026

Line No.	(a) Sub-Program	(b) Project Description, Line, Substation, or Location	(c) Projected Period Spending	(d) Units	(e) Unit Type	(f) Investment Category	(g) Location	(h) Benefit Type	(i) Benefit
	Capacity								
1	CVR	CVR_WEST RIVER_ GRAND RIVER	17	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	74
2		CVR_STEEL DRIVE_ OWEN ROAD	45	1	Circuit	Conservation Voltage Reduction	FENTON TWP	kW Energy Savings	167
3		CVR_WEST FENTON_ PARKWAY	53	1	Circuit	Conservation Voltage Reduction	FENTON TWP	kW Energy Savings	156
4		CVR_WYOMING PARK_ PORTER	59	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	203
5		CVR_RAMONA_ ROBINSON	20	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	122
6		CVR_RAMONA_ REEDS LAK	50	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	134
7		CVR_HANSEN_ HANSEN	67	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	158
8		CVR_BRIDGEPORT_ BRIDGEPORT	20	1	Circuit	Conservation Voltage Reduction	BRIDGEPORT TWP	kW Energy Savings	165
9		CVR_FAIRFIELD_ JASPER	20	1	Circuit	Conservation Voltage Reduction	MADISON TWP	kW Energy Savings	61
10		CVR_FAIRFIELD_ WESTON	8	1	Circuit	Conservation Voltage Reduction	MADISON TWP	kW Energy Savings	73
11		CVR_RUSSELL ROAD_ RAISIN	27	1	Circuit	Conservation Voltage Reduction	RAISIN TWP	kW Energy Savings	97
12		CVR_PINE RIVER_ WRIGHT	3	1	Circuit	Conservation Voltage Reduction	ARCADA TWP	kW Energy Savings	73
13		CVR_GILSON_ WYMAN	20	1	Circuit	Conservation Voltage Reduction	RICHLAND TWP	kW Energy Savings	86
14		CVR_ELM STREET_ CHAMPION	58	1	Circuit	Conservation Voltage Reduction	BATTLE CREEK	kW Energy Savings	160
15		CVR_OLIVET_ AINGER	4	1	Circuit	Conservation Voltage Reduction	WALTON TWP	kW Energy Savings	35
16		CVR_PRINCETON_ WATTLES	83	1	Circuit	Conservation Voltage Reduction	EMMET TWP	kW Energy Savings	150
17		CVR_PRINCETON_ BROWNLEE	13	1	Circuit	Conservation Voltage Reduction	EMMET TWP	kW Energy Savings	86
18		CVR_BEDFORD_ HALBERT	4	1	Circuit	Conservation Voltage Reduction	BEDFORD TWP	kW Energy Savings	37
19		CVR_CHAUNCEY_ CASS	37	1	Circuit	Conservation Voltage Reduction	SHERIDAN TWP	kW Energy Savings	101
20		CVR_AUBURN_ ELEVATOR	78	1	Circuit	Conservation Voltage Reduction	WILLIAMS TWP	kW Energy Savings	164
21		CVR_AUBURN_ AUBURN	66	1	Circuit	Conservation Voltage Reduction	WILLIAMS TWP	kW Energy Savings	149
22		CVR_ESSEXVILLE_ ESSEXVILLE	20	1	Circuit	Conservation Voltage Reduction	HAMPTON TWP	kW Energy Savings	143
23		CVR_PATTERSON_ PATTERSON	20	1	Circuit	Conservation Voltage Reduction	BANGOR TWP	kW Energy Savings	130
24		CVR_PATTERSON_ STATE	7	1	Circuit	Conservation Voltage Reduction	BANGOR TWP	kW Energy Savings	60
25		CVR_EAST JORDAN_ IRONTON	15	1	Circuit	Conservation Voltage Reduction	SOUTH ARM TWP	kW Energy Savings	125
26		CVR_STONEY CORNERS_ DAIRY	27	1	Circuit	Conservation Voltage Reduction	RICHLAND	kW Energy Savings	128
27		CVR_BRONSON_ MILL STREET	19	1	Circuit	Conservation Voltage Reduction	BRONSON TWP	kW Energy Savings	80
28		CVR_GIRARD_ GIRARD	20	1	Circuit	Conservation Voltage Reduction	GIRARD TWP	kW Energy Savings	48
29		CVR_GIRARD_ DAYBURG ROAD	12	1	Circuit	Conservation Voltage Reduction	GIRARD TWP	kW Energy Savings	68
30		CVR_HARRISON_ LILLEY LAKE	50	1	Circuit	Conservation Voltage Reduction	HAYES TWP	kW Energy Savings	112
31		CVR_CURTIS_ MAGRUDDER	9	1	Circuit	Conservation Voltage Reduction	EDENVILLE TWP	kW Energy Savings	54
32		CVR_MANNSIDING_ MANNSIDING	16	1	Circuit	Conservation Voltage Reduction	LINCOLN TWP	kW Energy Savings	48
33		CVR_BELSAY_ BELSAY	20	1	Circuit	Conservation Voltage Reduction	BURTON TWP	kW Energy Savings	155
34		CVR_CEDAR SPRINGS_ NELSON	242	1	Circuit	Conservation Voltage Reduction	SOLON TWP	kW Energy Savings	319
35		CVR_MAYFAIR_ MAYFAIR	8	1	Circuit	Conservation Voltage Reduction	MT MORRIS TWP	kW Energy Savings	57
36		CVR_MAYFAIR_ HOME	66	1	Circuit	Conservation Voltage Reduction	MT MORRIS TWP	kW Energy Savings	118
37		CVR_HOGAN ROAD_ MCCASLIN LAKE	53	1	Circuit	Conservation Voltage Reduction	ARGENTINE TWP	kW Energy Savings	126
38		CVR_HARRIET_ HARRIET	14	1	Circuit	Conservation Voltage Reduction	BURTON TWP	kW Energy Savings	70
39		CVR_RANKIN_ GREEN VALLEY	69	1	Circuit	Conservation Voltage Reduction	MUNDY TWP	kW Energy Savings	141
40		CVR_RANKIN_ TRAPANI	15	1	Circuit	Conservation Voltage Reduction	MUNDY TWP	kW Energy Savings	89
41		CVR_CENTER ROAD_ EASTLAND	17	1	Circuit	Conservation Voltage Reduction	BURTON TWP	kW Energy Savings	103
42		CVR_CENTER ROAD_ EVERGREEN	13	1	Circuit	Conservation Voltage Reduction	BURTON TWP	kW Energy Savings	105
43		CVR_SQUIRE HILL_ EDGEWATER	68	1	Circuit	Conservation Voltage Reduction	FLINT	kW Energy Savings	123
44		CVR_SQUIRE HILL_ HILLSIDE	28	1	Circuit	Conservation Voltage Reduction	FLINT	kW Energy Savings	95
45		CVR_GRANT_ CATALPA	10	1	Circuit	Conservation Voltage Reduction	ASHLAND TWP	kW Energy Savings	62
46		CVR_GRANDVILLE_ CANAL	20	1	Circuit	Conservation Voltage Reduction	WYOMING TWP	kW Energy Savings	49
47		CVR_HARVEY STREET_ SUNSHINE	60	1	Circuit	Conservation Voltage Reduction	GRAND RAPIDS	kW Energy Savings	142
48		CVR_HUDSONVILLE_ 32ND	49	1	Circuit	Conservation Voltage Reduction	GEORGETOWN TWP	kW Energy Savings	117
49		CVR_HASKELITE_ ANN STREET	20	1	Circuit	Conservation Voltage Reduction	WALKER TWP	kW Energy Savings	114
50		CVR_WALKER_ REMEMBRANCE	188	1	Circuit	Conservation Voltage Reduction	WALKER TWP	kW Energy Savings	252
51		Identified CVR Voltage Remediation Upgrades	500			Conservation Voltage Reduction	MICHIGAN	kW Energy Savings	-
52		**CVR Total**	**2,429**						



Consumers Energy

Conservation Voltage Reduction Measurement and Verification Independent Assessment

May 2021

ESTA International, LLC
21525 Ridgetop Circle, Suite 200
Sterling, Virginia, 20166
USA

www.ESTAInternational.com



EXECUTIVE SUMMARY

Conservation Voltage Reduction (CVR) is the practice of reducing service delivery voltage to the lower portion of the acceptable industry range as specified in ANSI Standard C84.1 to reduce energy consumption for waste energy reduction purposes and/or reduce peak electrical demand. Consumers Energy of Jackson, Michigan has conducted a CVR Demonstration Project that included implementing CVR on fifty of its electric distribution feeders that are located throughout the Consumers Energy service territory and has been operating in CVR reduced-voltage mode on alternating days since 2019.

To determine the waste energy and peak demand reduction that can be attributed to voltage reduction, Consumers Energy has conducted a Measurement and Verification (M&V) analysis of the electrical measurement data collected for each of the fifty feeders during the period of CVR alternating-day (aka, "day-on/day-off") operation. This analysis separates the electrical impacts of voltage reduction from other factors that affect the energy consumption and peak electrical demand, such as naturally varying custom behavior and ambient weather conditions, as well as variations in energy consumption for different hours of the day, days of the week, seasons, and other temporal variations.

In January 2021, Consumers Energy hired ESTA International, Ltd. (ESTA), an independent consulting firm specializing in electric utility automation and energy analysis to review and critique the Consumers Energy CVR project and associated M&V analysis performed by Consumers Energy. This report summarizes the results of this assessment.

M&V ASSESSMENT FACTORS

ESTA's assessment of the Consumers Energy CVR M&V approach included the following items:

- Process for Selecting Feeders. Consumers Energy will use the results of the CVR demonstration project to determine whether CVR implementation on additional feeders is justified. Therefore, the 50 feeders selected for the CVR demonstration should have characteristics (customer mix, regional distribution, etc.) that are representative of other Consumers Energy feeders on which CVR may be implemented in the future. Consumers Energy used a two-step process for selecting feeders for the CVR demonstration:

    - During Step 1, Consumers Energy identified 1,700 feeders that are viable candidates for implementing CVR based on factors such as availability of remote-controlled devices and telecommunication facilities. These feeders are labeled the "CVR Proposed" set.

    - During Step 2, Consumers Energy selected 50 feeders from the CVR Proposed set on which to implement CVR for demonstration purposes. In selecting these 50 feeders, preference was given to feeders with characteristics that best match the CVR proposed set. Preference was given to feeders that have a similar mix of residential, commercial and industrial customers.

  The feeder selection process used by Consumers Energy is far more detailed and superior to the selection process used by other utility companies. In ESTA's opinion, the selected CVR feeders are representative of the CVR Proposed set of feeders and, therefore, it is acceptable to assume that similar results will be obtained as CVR is added by Consumers Energy to additional feeders.

- CVR System. The CVR system deployed by Consumers Energy is like most CVR systems that have been deployed in the past 5 to 10 years by other electric utilities. This system applies fixed "rules" that have been predetermined by Engineering to real-time measurements obtained by the Consumers Energy SCADA system to determine what control actions (if any) are needed for switched capacitor banks and voltage

regulators. The CVR system automatically switched between CVR-On mode (reduced voltage) to CVR Off mode (normal voltage) on alternating days. In ESTA's opinion, the rules-based approach is a cost-effective approach that is well suited to the project's "proof of concept" objectives. One shortcoming of this approach is that the system must be disabled for a given feeder if that feeder is reconfigured. This is not a major problem because such reconfiguration is infrequent. However, ESTA recommends a "model-driven" approach to CVR that automatically adapts when feeders are reconfigured. This approach can be implemented on the new Consumers Energy ADMS.

- Controlled Devices: The Consumers Energy CVR system controls switched capacitor banks and voltage regulators as needed to accomplish the CVR objectives. This is consistent with industry practice. Consumers Energy has a significant advantage over many other utility companies because voltage regulation is done on an individual-feeder basis. This enables Consumers Energy to reduce voltage on some feeders even if other feeders fed by the same substation are "voltage limited". In the future, control of other devices such as Distributed Energy Resources (DERs) with "smart inverters", may be required by Consumers Energy. The previously mentioned model-drive solution will be able to handle the addition of such devices.

- Data Collected During the Demonstrations: ESTA reviewed the list of electrical measurements collected during the CVR demonstrations to determine if the measurements taken are sufficient for effective operation of the CVR algorithms and determining the CVR factors. ESTA concludes that the collected data is consistent with the data collected by other utilities and is sufficient for computing the CVR factors for the CVR demonstration feeders. Some "data scrubbing" was performed by Consumers Energy to eliminate data anomalies. However, ESTA notes that the amount of data scrubbing needed by Consumers Energy for its data was much less than the data scrubbing needed by other utilities, indicating that the Consumers Energy data quality, in general, is very good.

- Method of Computing CVR factors for Waste Energy Reduction and Peak Demand Reduction. ESTA reviewed the method used by Consumers Energy to compute the CVR factors. Consumers used a method called "Matching Pairs" to compute a CVR factor, which is an important metric for CVR effectiveness. The Matching Pairs method compares weekday load and voltage measurements with reduced voltage (CVR On days) to weekday measurements when normal voltage normal voltage was applied (CVR Off days). Separate calculations were performed for each season because average ambient temperature can have a significant impact on CVR factor. having similar ambient temperature. The resulting CVR factor for Waste Energy Reduction was 0.82, meaning that when voltage is reduced by 1%, load is reduced by 0.82%. The result is consistent with results obtained by other utility companies, which generally fall in the range of 0.7 to 0.8.

  The most common method used in the industry to calculate CVR factors is multiple regression analysis to determine the impact of ambient temperature, voltage, and other factors on load. To confirm the results obtained by Consumers Energy, ESTA performed an independent calculation of CVR factor using regression analysis on the data supplied by Consumers Energy. The result of this analysis was a CVR factor of 0.77 +/- 3.7%. In ESTA's opinion, the results of this independent calculation confirms the accuracy of the Consumers Energy matching pairs method.

  ESTA also used the regression method to determine a CVR factor for Peak Reduction. The Peak Reduction CVR factor is typically significantly different than the Waster Energy Reduction CVR factor because the equipment complement and consumer appliances are different during peak load conditions than the on-line equipment complement during off peak periods. The results of this analysis is a Peak CVR factor of 1.51 with a model error of +/- 3.89%. ESTA is only aware of one utility (undisclosed) that has published a Peak

Demand CVR factor. The published CVR factor was 1.45, which is comparable the results obtained by ESTA.

Later this year, Consumers Energy is planning to use a load forecasting software tool called "MetrixND" (supplied by ITRON) for computing CVR factors. This software tool uses regression analysis to estimate what the load "would have been" with normal voltage for a given day of week an average ambient temperature. ESTA strongly recommends using this type of analysis for determining CVR factors.

CONCLUSIONS

For reasons given above, ESTA concludes that the CVR system software and hardware are well-suited and adequate for conducting the CVR demonstration and that the results obtained for the 50-feeder demonstration can be applied to other Consumers Energy feeders. While the "Matching Pairs" method used by Consumers Energy for computing CVR factor is somewhat unique, the results obtained using this approach match the independent calculations performed by ESTA reasonably well.

Going forward, ESTA encourages Consumers Energy to implement the MetrixND method, not only for estimating peak demand reduction but also for distribution load forecasting in general. ESTA also recommends that Consumers Energy implement a model-driven, ADMS-based approach to CVR because this approach has operational advantages described in this report.

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Purpose of this Document:

This document summarizes the processes and procedures to be used by the project team members.

Ver. No.	Description	Prepared By	Reviewed By
0	Initial Document for Comments	Bob Uluski	Spandan Gandhi
1	Additional sections added	Bob Uluski	Spandan Gandhi
2	Final Draft Version of Report	Bob Uluski	Spandan Gandhi
3	Final Report	Bob Uluski	Spandan Gandhi

1 INTRODUCTION

Conservation Voltage Reduction (CVR) is the practice of reducing service delivery voltage to the lower portion of the acceptable industry range as specified in ANSI Standard C84.1 to reduce energy consumption for waste energy reduction purposes and/or reduce peak electrical demand. Consumers Energy of Jackson, Michigan has conducted a CVR Demonstration Project that included implementing CVR on fifty of its electric distribution feeders that are located throughout the Consumers Energy service territory and has been operating in CVR reduced-voltage mode on alternating days since 2019.

To determine the waste energy and peak demand reduction that can be attributed to voltage reduction, Consumers Energy has conducted a Measurement and Verification (M&V) analysis of the electrical measurement data collected for each of the fifty feeders during the period of CVR alternating-day (aka, “day-on/day-off”) operation. This analysis separates the electrical impacts of voltage reduction from other factors that affect the energy consumption and peak electrical demand, such as naturally varying custom behavior and ambient weather conditions, as well as variations in energy consumption for different hours of the day, days of the week, seasons, and other temporal variations.

The results of the CVR M&V analysis conducted by Consumers Energy indicate that the CVR factor, an important metric for measuring the load-to-voltage sensitivity, ranges from 0.07 to 1.34 for the 50 feeders that Consumers Energy has analyzed. This means that reducing the voltage applied to these electric distribution feeders by 1% will reduce electrical demand on these feeders by between 0.07% and 1.34% without any adverse electrical impacts or load shedding by Consumers Energy customers. The average CVR factor for the 50 CVR circuits is 0.82, which is consistent with CVR factors reported by other electric distribution utilities that have implemented CVR.

Consumers Energy is seeking an independent assessment of its CVR efforts to verify the results to date and assist Consumers Energy in determining whether implementing CVR on additional feeders would be beneficial to Consumers Energy and its customers. In January 2021, Consumers Energy hired ESTA International, Ltd. (ESTA), an independent consulting firm specializing in electric utility automation and energy analysis to review and critique the Consumers Energy CVR project and associated M&V analysis performed by Consumers Energy. This report summarizes the results of this assessment.

2 SCOPE OF THE INDEPENDENT CVR ASSESSMENT

The objective of the consulting assignment is to review and critique the methods used by Consumers Energy to conduct the Day-On/Day-Off CVR demonstration and to assess the method used to analyze the resulting data to determine the CVR factor, which is an important performance metric for CVR. ESTA's assessment included the following items:

- Process for Selecting Feeders. ESTA reviewed and critiqued the method Consumers Energy used to select the feeders on which the CVR demonstration was performed. Ideally, the selected feeders are representative of Consumers Energy feeders where it is practical and economical to implement CVR. That is, the selected feeders should have characteristics that are like the characteristics of the larger set of feeders on which CVR could be implemented. Such characteristics included (but were not limited to) feeder length and configuration, customer mix (residential, commercial, industrial), and location (North, South, East, West).

- CVR Software Algorithms. ESTA reviewed the algorithms and principles of operation of the CVR application software (furnished by the Consumers Energy Distribution Management System (DMS) supplier OSI International (OSII)) to gain a thorough understanding of the approaches used for 24-hour-a-day energy conservation and peak demand reduction.

- Controlled Devices: ESTA reviewed the list of devices that are controlled by the CVR application software, such as feeder voltage regulators and switched feeder capacitor banks. The feeders in question do not include significant penetrations of Distributed Energy Resources (DERs) such as rooftop solar photovoltaic generators which can affect the distribution feeder voltage and reduce the "net" load measured on the feeder. Hence, the DER impact on the results of this study are not significant.

- Data Collected During the Demonstrations: ESTA reviewed the list of electrical measurements collected during the CVR demonstrations to determine if the measurements taken are sufficient for effective operation of the CVR algorithms and determining the CVR factors. ESTA also reviewed the methods used for "data scrubbing" that is needed to eliminate data anomalies, such as bad and missing data, that may produce incorrect results.

- Method of Computing CVR factors for Waste Energy Reduction and Peak Demand Reduction. ESTA reviewed the method used by Consumers Energy to compute the CVR factors. The objective of this activity was to determine if the analytical methods are accurate and consistent with establish industry practices. ESTA compared the Consumers Energy methodology with the analytical approaches described in IEEE Standard 1885: "Guide for Assessing, Measuring and Verifying Volt-Var Control Optimization on Distribution Systems" to ensure consistency with this standard.

ESTA compared the Consumers Energy approach for each of the items listed above against the approach used by other electric distribution utilities that have similar characteristics to Consumers Energy and have already implemented CVR to determine if the Consumers Energy approach is consistent with best industry practices.

In addition to the assessment of Consumers Energy CVR M&V strategy described above, the project also includes developing a mechanism for predicting what CVR factor would be achieved by implementing CVR on additional feeders. This mechanism is described later in a separate report.

3 QUALIFICATIONS OF ESTA FOR PERFORMING THIS ASSESSMENT

ESTA is uniquely qualified for performing this assessment of Consumers Energy CVR projects and results for reasons stated below:

- ESTA has recently completed a detailed M&V assessment of CVR for Consolidated Edison of New York and has also conducted similar assessments for other utility companies that are similar in size and electrical characteristics to Consumers Energy.

- ESTA's team lead, Mr. Robert Uluski, has served as Chair of the IEEE's Power and Energy Society Task Force on Volt-VAR control and optimization and played a lead role in developing IEEE Standard 1885: "Guide for Assessing, Measuring and Verifying Volt-Var Control Optimization on Distribution Systems". This standard identifies ways in which electric distribution utilities can evaluate the CVR benefits. This standard was recently approved and published by IEEE. Mr. Uluski has also managed EPRI's "Smart Distribution" research program that included extensive work in laboratory testing to identify load-voltage sensitivity of major electrical appliances and equipment and in load-voltage modelling.

- ESTA's energy analyst, Mr. Spandan Gandhi, has considerable experience in advanced techniques for CVR M&V, including use of neural nets and multiple-regression analysis for modelling and analyzing the impacts of voltage reduction, as well as data scrubbing to identify data anomalies that can distort the M&V results.

- ESTA is a fully independent consulting firm that has no relationships with any system vendor and no vested interest in any commercial product. As a result, our findings, conclusions, and recommendations are completely unbiased by any such relationships.

4 LIST OF ACRONYMS

Following is a list of acronyms and key terms used in this report.

Table 4-1 List of Acronyms

Acronym/ term	Description
AMI	**Advanced Metering Infrastructure -** Facilities for periodically measuring and reporting customer electrical consumption at intervals of an hour or less for billing purposes, and for determining customer consumption patterns. AMI outputs in the form of "last gasp" messages have become a commonly-used mechanism for detecting power outages at individual customer sites. AMI may also be used for detecting low or high voltage conditions and the customer meter and reporting such conditions to the system operator and other persons responsible for outage management.
ANSI	**American National Standards Institute** - a private, non-profit organization that administers and coordinates the U.S. voluntary standards such as C48.1 ("Electric Power Systems Voltage Ratings")
CVR	**Conservation Voltage Reduction** - the process of intentionally reducing the voltage on a distribution circuit to the lower portion of the acceptable voltage range permitted by ANSI standard C84.1.
Day-On/Day-Off	A process of activating a system (such as CVR) on alternating days, and comparing measurements recorded during the "system on" day versus the "system off" day. of comparing
DER	**Distributed Energy Resource -** small scale generators, energy storage units, and controllable loads that are connected to the electric distribution system in close proximity to the load centers. DERs are most commonly used today to supply real and reactive power and curtail load when needed, the objective being to lower dependence on large scale centralized generators and high voltage transmission line as the sole source of supply. In addition, some DERs, such as solar and wind power are renewable energy sources that can help lower greenhouse gas emissions.
DMS	**Distribution Management System** - a computer and communication system the enables electric distribution system operators to monitor and control the distribution system assets and overall electric distribution system performance from the distribution control center.
DR	**Demand Reduction -** a set of processes used to curtail electrical consumption during system emergencies.
DSCADA	**Distribution Supervisory Control and Data Acquisition -** a computer and communication system that enables distribution system operators to monitor and control electric system power apparatus from a control center. The SCADA system is a fully integrated element of the Consumers Energy DMS.
EPRI	**Electric Power Research Institute -** an American independent, nonprofit organization that conducts research and development related to the generation, delivery, and use of electricity to help address challenges in electricity, including reliability, efficiency, affordability, health, safety, and the environment.
ESTA	**ESTA International, Ltd** - an independent consulting firm specializing in the planning, implementation, and the post-implementation analysis of benefits associated with electric utility automation systems. Consumers Energy hired ESTA to perform an independent assessment of its CVR system.

IEEE	**Institute of Electrical and Electronic Engineers -** a large worldwide professional association for electronic engineering and electrical engineering. IEEE is one of several recognized standards-making bodies for electric power systems.
kVAR	**Kilo-volt-ampere-reactive -** A measure of reactive power
LTC	**Load Tap Changer -** A device that automatically regulates the voltage supplied by a substation transformer to the electric distribution feeders. Note that Consumers Energy uses voltage regulators on individual feeders and does not use LTCs.
M&V	**Measurement and Verification** - the process of using measurements to determine actual savings created within an individual facility by an energy management, energy conservation or energy efficiency project or program. M&V is commonly used for estimating the benefits that cannot be measured directly, such as CVR benefits.
OSII	**Open Systems International, Inc, -** the system vendor that supplied the Consumers Energy ADMS that is used to implement CVR.
VVO	**Volt-VAR Optimization -** A software application running on the DMS for improving the efficiency and voltage quality on the electric distribution system. CVR is a subfunction of VVO.

5 ESTA ASSESSMENT OF CONSUMERS ENERGY CVR PROGRAM AND M&V APPROACH

ESTA's assessment of each of the items related to Consumers Energy CVR program is contained in the following sections. The following items are included:

1. Feeder Selection
2. CVR Software Algorithms
3. Controlled Devices
4. Data Collection
5. Method of Computing CVR factor

For each of the items listed above, ESTA has provided the following information:

a) General requirements pertaining to each item.
b) ESTA's understanding of the Consumers Energy approach for each item.
c) Comparison of Consumers Energy approach to best industry practices.
d) ESTA's Findings, conclusions, and overall assessment of Consumers Energy approach to each item.

5.1 FEEDERS SELECTED FOR CVR IMPLEMENTATION

The purpose of this section is to determine if the CVR benefit results for subset of feeders selected for this CVR demonstration project are representative of the CVR benefits that could be gained by implementing CVR on additional feeders.

a) General Requirements and Industry Practice for Feeder Selection

- Feeders should not be "voltage limited". If the service delivery voltage on a given feeder is near the low limit specified in ANSI standard C84.1 at one or more feeder locations during some loading conditions, it may not be possible to reduce voltage when needed. Feeder infrastructure improvements (reconductoring, etc.) may be needed to "flatten" the voltage profile on voltage-limited feeders and provide a suitable operating margin for voltage reduction.

- The customer mix (percentages of residential, commercial, and industrial customers) served by the feeder should be representative of the typical customer mix on other Consumers Energy feeders. Consumers Energy should not select a feeder that has a unique customer mix because results for that feeder may not be indicative of results that may be obtained on other Consumers Energy feeders.

- Voltage and VAR control devices on the feeder should be equipped with remote control capabilities that are needed for the Consumers Energy CVR system (see Section 5.2 for a description of the Consumers Energy CVR system).

- Feeders should have a suitable mechanism for determining the lowest voltage on the feeder. This will provide feedback to the CVR software to ensure voltage is not reduced below the low voltage limit specified in the ANSI standard.

- The feeders selected for CVR demonstration should be widely dispersed throughout the Consumers Energy service territory because the results for feeders in different geographic regions may be different. For example, the results for feeders in the Northern portion of the state may differ from feeders in the Southern portion of the state due to different energy consumption for heating and cooling in these two regions.

b) ESTA's Understanding of the Consumers Energy Approach to Feeder Selection

Consumers Energy used a two-step process for selecting feeders on which to implement CVR during the CVR demonstration project, as described below:

1. During step one of this process, Consumers Energy created a "CVR Potential" circuit pool consisting of approximately 1,700 distribution feeders that are viable "candidates" for CVR implementation. Feeders with the following characteristics were selected for the CVR Potential circuit pool:

    i. Feeder has substation DSCADA telemetry to enable remote monitoring and control capabilities. The Consumers Energy CVR system requires near-real-time DSCADA measurement data, such as reactive power flow, to determine if feeder capacitor bank switching is required. In addition, the CVR Potential circuits must have upgraded line voltage regulators that can be monitored and controlled by DSCADA and the CVR system

    ii. Circuit is not a Dedicated-Customer circuit. Most dedicated customer circuits have unique loading characteristics so the results would not be representative of other Consumers Energy circuits.

    iii. The circuit is not supplied by a delta (3-wire) substation. There are relatively few delta circuits at Consumers Energy, so the CVR results for this type of feeder would not be representative. In addition, the CVR control logic would be more complicated than wye-grounded (4-wire) circuits.

    iv. At least 50% of the customers on the feeder are residential customers. Circuits that primarily serve Commercial and Industrial customers (i.e., % of C/I customers greater than 66%) were excluded from the CVR potential circuits. Feeders with a proportionately higher number of residential customers is common at Consumers Energy, so circuits that serve a high percentage of residential customers are more representative of Consumers Energy distribution feeders.

2. During step 2 of the selection process, Consumers Energy selected 50 of the CVR Potential feeders with characteristics that are most representative of the total set of CVR Potential distribution feeders. Factors considered in selecting the 50 CVR feeders from the CVR Potential list of feeders included customer type breakdown, Archetype, circuit length, customer count, and the percentage of residential customer. ESTA's assessment of each of these feeder selection criteria is provided below:

a) **Customer Type Breakdown:** Customer type breakdown (or the percentages of residential, commercial, and industrial customers on a given feeder) is the primary factor used by Consumers Energy in selecting the CVR feeders from the CVR Potential list. The CVR factor is primarily impacted by the types of customers served by the feeder and the complement of electrical equipment and appliances used by these customers. Therefore, selecting feeders with customer type breakdown that matches the CVR Potential Set is critical for identifying representative feeders for CVR deployment. ESTA computed the customer type breakdown of feeders that were selected for CVR and the CVR Potential group. As seen in below, the differences in percentage mix of customers in the selected set and the CVR Potential set are very small. Therefore, ESTA concludes that the selected CVR circuits are representative of the Consumers Energy CVR potential feeders.

Table 5-1 Comparison by Customer Type Breakdown

	Customer Type Breakdown		
Customer Type	CVR Potential	CVR Selected	Difference
% Commercial	13.3%	11.5%	1.8%
% Industrial	0.2%	0.1%	0.1%
% Residential	84.8%	86.9%	-2.1%

b) **Archetype:** ESTA compared the Archetype breakdown for the selected CVR circuits with the Archetype breakdown for the CVR Potential group, as shown below. The breakdown of feeders by Archetype in the selected CVR set of feeders differs from the CVP Potential set by between 0% and 9%. The most significant difference is that a higher percentage of urban circuits (Archetypes 3 and 4) was selected over rural circuits (Archetypes 5, 6, and 7). In ESTA's opinion, the choice of urban feeders over rural feeders is justified, because urban feeders usually provide higher overall CVR benefits than rural circuits due to shorter length (less voltage drop) and heavier loading (more kWh reduction per unit voltage reduction). ESTA also believes, based on industry experience, that the percentages of rural feeders in the CVR Potential set are too high and that it is unlikely the Consumers Energy would actually add CVR to such a high number of rural circuits due to the lower payback opportunity.

Table 5-2 Comparison by Archetype

Archetype	Archetype Description	CVR Potential	CVR Selected	Difference
0	Circuit has not been assigned an Archetype Value yet	1%	0%	1%
1	Most Large C&I customers, short circuits that are primarily underground, best reliability	2%	25	0%
2	Circuits with greatest mix of customers and high proportion of small C&I, moderate reliability	11%	16%	-5%
3	Urban residential customers, short lines with high customer density, strong reliability, high NPS	14%	18%	-4%
4	Urban customers, longer circuits with high customer density that are more susceptible to outages	27%	36%	-9%
5	Rural circuits primarily in central/south, better reliability than rural circuit peers	20%	12%	8%

6	Rural circuits, low customers per line mile, high frequency of outages and long outage durations	15%	12%	3%
7	Rural customers primarily in the north, longest circuits, worst reliability across the system	10%	4%	6%
8	Radial, unshielded, higher risk HVD groups	0%	0%	0%
9	Core, looped HVD system	0%	0%	0%

c) **Circuit Length:** In general, circuit length does not have a significant impact on the CVR factor. However, since longer feeders will experience a greater voltage drop over the length of the feeder, feeder length impacts the percent voltage reduction that is possible, and therefore, impacts the CVR benefit (lower energy savings and smaller peak shaving possible). Table 5-3 shows the length breakdown of feeders in the selected CVR set of feeders and the CVR Potential circuits. As can be seen in the table, the selected CVR feeder set has a significantly higher percentage of shorter feeders than the CVR Potential set. In ESTA's opinion, this difference is not a matter of concern when computing CVR factor, because, as stated above, feeder length by itself does not impact CVR factor.

Table 5-3 Comparison by Feeder Length

Feeder length (Miles)	CVR Potential	CVR Selected	Difference
0-10	18.6%	40.0%	-21.4%
10-25	31.3%	24.0%	7.3%
25-40	19.2%	24.0%	-4.8%
40-55	14.1%	4.0%	10.1%
56+	16.8%	8.0%	8.8%

d) **Residential Percentage:** ESTA compared the residential percentages in the selected CVR circuits with the residential percentages in the CVR Potential circuit pool. As can be seen in this table, the percentage of residential customers matches reasonably well between the selected CVR circuits and the CVR Potential circuits except for circuits where the percentage of residential customers is less than 80%. Since the Consumer Energy focus is on feeders that have a high percentage of residential customers, this difference should not be a significant problem. Hence, ESTA concludes that here is a good match in residential customer percentages between to the two sets of circuits.

Table 5-4 Comparison by Residential Percentage

% Residential	CVR Potential	CVR Selected	Difference
0-80%	19.4%	8.0%	10.6%
80-85%	19.5%	24.0%	-4.5%
85-90%	30.9%	36.0%	-5.1%
90-100%	30.2%	32.0%	-1.8%

e) Customer Count: As can be seen in Table 5-5, the breakdown of total customer count for the selected feeders matches very well with the breakdown of customer count for the CVR Potential circuits.

Table 5-5 Comparison by Customer Count

Customer Count	CVR Potential	CVR Selected	Difference
0-500	17.7%	18.0%	-0.3%
501-1000	34.2%	32.0%	2.2%
1001-1500	26.6%	24.0%	2.6%
>1500	21.5%	26.0%	-4.5%

f) Other comparisons

- **Region:** Feeder location can have a significant impact on CVR factor, especially for circuits that are in the Northern versus Southern portions of the State of Michigan. The latitude and longitude of the selected CVR circuits is consistent with the Potential CVR circuit pool. The feeders in both the circuit pool and the selected set are primarily located in the southern and central part of the State, with a few outliers in the North. Both sets appear to be split equally between substations in the Eastern and Western parts of the State. Note that the North and south difference is more significant when computing a CVR factor, because energy consumption patterns and associated CVR factors may be different for northern (colder) regions and southern (warmer) regions of the state.

c) **Comparison of Consumers Energy approach to best industry practices**

Several other factors may be considered when selecting circuits for CVR:

a. **Worst performing feeders:** Some utilities have elected to implement CVR (and the broader application Volt-VAR Optimization) on circuits that have historically experienced low power factor. The VVO application can improve power factor and thus reduce losses on these worst performing feeders in addition to accomplishing peak shaving and energy conservation using CVR.

b. **Heavily Loaded Circuits:** Heavily loaded circuits are often selected (provided they are not voltage limited) because the energy savings and peak shaving benefits for a given amount of voltage reduction are greater for a given circuit than a lightly loaded feeder having the same CVR factor.

c. **Groups of Feeders from Same Substation:** Groups of feeders fed off the same substation bus are usually selected for CVR at the same time. This is because voltage reduction actions are performed by a substation load tap changer (LTC) transformer which impacts all feeders that are connected to the low side bus of the transformer. This does not apply to Consumers Energy, which uses individual feeder voltage regulators.

d) **Findings, conclusions, and overall assessment of Consumers Energy approach**

In ESTA's opinion, the process used by Consumers Energy for selecting feeders for its CVR demonstration far exceeds the feeder selection process used by other utilities that have demonstrated and/or implemented CVR. Most utilities have selected feeders based on a limited set of factors such as the availability of DSCADA and remotely controllable volt-VAR devices (feeder capacitor banks and voltage regulators).

Based on the analysis described above, ESTA concludes that the feeders that have been selected by Consumers Energy for CVR are representative of the broader set of CVR Potential feeders. This conclusion is based primarily on the customer type breakdown which matches well between the two groups of feeders. While there are some differences in other selection criteria between the selected CVR circuits and the CVR Potential group of feeders, these factors in general should not have a major impact on the overall CVR factors.

In the case of Archetype differences between the two sets of feeders, ESTA concludes this is due to having too many rural feeders in the CVR Potential set. If the percentages of rural feeders in the CVR Potential set are reduced, the two sets would have comparable breakdowns by Archetype.

As a result, it is reasonable to conclude that the CVR factors computed for the selected feeders are representative of the results that will be obtained if CVR is applied to other circuits in the CVR Potential circuit pool.

5.2 CVR SOFTWARE ALGORITHMS

In this section, ESTA compared the Consumers Energy CVR system with CVR systems that are that have been implemented by other utilities in North America.

a) General Requirements

a. The CVR system should be able to lower the voltage on selected distribution feeders by a Consumers Energy-specified amount to achieve a reduction in waste energy and/or peak electrical demand.

b. A suitable mechanism should be provided to ensure that the service delivery voltage at all customer meters on the feeder does not go below the limits specified in applicable ANSI standards when CVR is activated. CVR must be transparent to the consumers and must not adversely impact the operation of customer-owned equipment.

c. The CVR system shall be able to operate in either of the following Consumers Energy-selectable modes:
    i. Energy Waste Reduction mode: In this mode, voltage shall be reduced by the specified amount whenever possible, up to 24 hours per day. The objective of this mode is to reduce energy (MWh) consumption without customer load shedding for overall efficiency improvement.

ii. Peak Demand Reduction mode: In Peak Demand Reduction mode, the voltage is lowered for a few hours during which peak demand occurs, with normal voltage applied during other hours. For example, if peak load occurs at 5:00 PM, voltage may be reduced between 4:00PM and 6:00PM, with normal voltage being applied during other hours. The objective of this mode of operation is to reduce the maximum load in megawatts on the feeder. The Peak Demand Reduction algorithms shall ensure that restoration of normal voltage following the CVR peak shaving event does not create a new peak; this can happen when diversity of thermostat-controlled devices is diminished during the voltage reduction period.

d. The CVR algorithms shall ensure that voltage and VAR control devices are properly time coordinated so that "hunting" and contradicting control actions are avoided. For example, control actions by voltage regulators to lower the feeder voltage should not be immediately followed by switched capacitor banks operating to raise the voltage.

e. The CVR algorithms shall not initiate improper or invalid voltage control and VAR control commands when the feeder is reconfigured. Feeder reconfiguration can change the position of capacitor banks and midline voltage regulators relative to the power source which, in turn, can result in improper coordination between devices. Furthermore, CVR shall not attempt to control any switched capacitor bank, voltage regulator, or other VVC device that is tagged out of service.

f. The control strategy for volt-VAR devices shall respect device operating restrictions, such as capacitor bank closing within the capacitor bank discharge time and prevention of "local" regulator over-voltages ("first house" protection).

g. The system shall include mechanisms for monitoring the operation of individual capacitor banks, voltage regulators, controllers, and communication facilities and shall be able to detect failures in any of these components that would prevent the device from operating as needed upon command. Failed components should be excluded from the CVR control strategy.

b) ESTA's understanding of the Consumers Energy approach

a. The Consumers Energy CVR approach is best described as a "rules-based" approach. That is, the CVR logic compares SCADA measurements against predetermined setpoints and then initiates control actions based on "if-then-else" rules. For example, if the reactive power flow to the feeder exceeds a specified setpoint, then switch a capacitor bank on the feeder to the "ON" position; otherwise do nothing. Figure 5-1 depicts a SCADA rules-based solution such as that used by Consumers Energy. Simply stated, when reactive power flow measured at the substation end of the feeder exceeds a pre-determined threshold, the CVR system sends commands to one or more capacitor bank switches, which, in turn, reduces the reactive power flow from the substation.

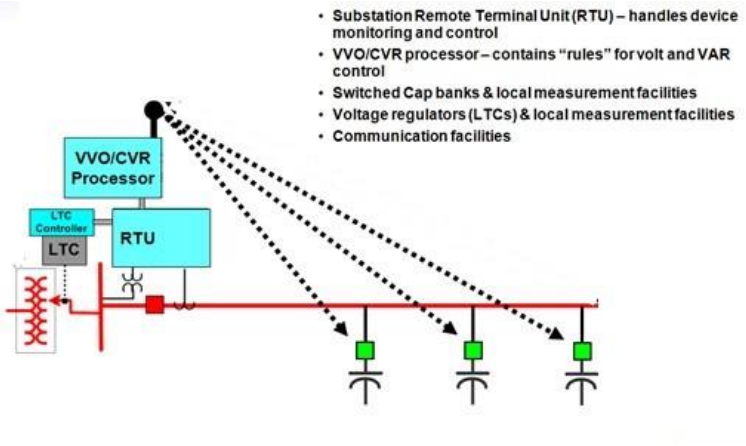


Figure 5-1 SCADA Rules Based CVR System

b. The CVR system setpoints and operating strategies that have been incorporated in the CVR logic have been determined in advance for each feeder by the Consumers Energy Distribution Engineering group using power flow analysis. These setpoints and control strategies have considered "worst case" (e.g., heavy load) conditions to ensure that the recommended CVR control actions will not produce unacceptable, adverse electrical conditions (low or high voltage, equipment overloads, etc.).

c. CVR is currently configured (for demonstration and M&V purposes) to run on alternate days (also known as Day-On/Day-Off strategy). Each day at approximately midnight, the CVR system automatically switches to the opposite operating mode (reduced voltage mode to normal voltage mode or normal voltage mode to reduced voltage mode).

d. To provide proper time coordination of voltage regulators and capacitor banks and avoid "hunting", Consumers Energy has incorporated the following rules in its CVR system:

i. Capacitor banks are controlled first, followed by voltage regulators.

ii. Device coordination is accomplished using different pre-determined time delays on each device.

iii. Capacitor banks that are closest to the load center (i.e., furthest from the source) are switched on first. This allows upstream capacitor banks to see the change in reactive power flow caused by downstream capacitor banks switching before operating to prevent overcompensation.

iv. Voltage regulator control actions (raise or lower tap position) are first executed on substation voltage regulators, followed by the control of midline voltage regulators.

e. Capacitor bank switching is initiated by the CVR software whenever the reactive power flow measured at the substation end of the feeder exceeds a predetermined amount (typically set at +/-

400 kVAR). The CVR system selects the capacitor bank that is closest to the load center (furthest from the substation) whose size in kVAR does not exceed the measured amount. After this capacitor bank is switched, the logic is repeated until no additional capacitor bank switching is possible.

f. If the measured VAR flow at the substation end of the feeder becomes negative (reactive power flow back into the substation (i.e., leading power factor)), the CVR software will switch off capacitor banks using similar logic to that described above (i.e., largest capacitor banks that are closest to the load center switched off first).

g. After a predetermined delay to allow capacitor bank switching to complete, voltage regulator operation is permitted using the predetermined Energy Waste Reduction settings. If midline voltage regulators are present, the time delay for these voltage regulators will be larger than the time delay for the substation voltage regulator for proper time coordination of substation and midline devices.

h. Peak Demand reduction is activated manually by the Distribution Operator during periods when peak shaving is required, such as during Merchant Operations demand reduction (DR) events. The logic used by Peak Demand Reduction CVR logic for controlling capacitor banks and voltage regulators is the same as Energy Waste Reduction. However, the logic is triggered at the start of the event (an hour or two before the system peak) and returned to normal an hour or two following the system peak.

i. If the feeder is reconfigured for any reason, the CVR logic is disabled to avoid switching capacitor banks that are no longer connected to its normal feeder and to avoid improper time coordination due to having a different location of a device relative to its source. It is not practical to incorporate additional rules to handle all the possible switching combinations using simple Boolean logic, and maintenance of such complex logic would be labor intensive. When the CVR system is disabled, the distribution voltage and reactive power control strategy reverts to local autonomous control performed by the individual device controllers.

j. Customer voltages reported by the Consumers Energy Advanced Metering Infrastructure (AMI) are checked the following day to determine if any low or high voltage deviations occurred during the previous day's voltage reduction actions. If frequent voltage deviations are observed for a given customer meter or location, the voltage regulator and capacitor banks settings for the associated feeder are adjusted as needed to avoid reoccurrence of these deviations. If necessary, feeder infrastructure improvements (e.g., reconductoring) may be implemented to eliminate significant voltage deviations that cannot be mitigated by setting changes alone.

c) Comparison of Consumers Energy approach to best industry practices

a. Most of the existing CVR solutions that today's electric utilities have implemented are SCADA "rule-based" systems that use logic like the Consumers Energy CVR system. That is, control decisions are based on "if-then-else" (Boolean) logic performed on measurements received from the utility's distribution SCADA system.

b. Some utilities use proprietary CVR solutions offered by vendors such as Utilidata, Dominion Voltage, Eaton IVVC, and other system vendors. These proprietary solutions are often considerably more expensive per substation then SCADA rules-based solutions due to the sophisticated algorithms and additional hardware needed to identify and implement required control actions. Incremental benefits offered by these systems include the potential for fewer voltage regulator tap position changes and nearly-real-time voltage feedback from strategic feeder locations for rapid detection and correction of voltage deviations. Note that the solution type does not impact the CVR factor, which is determined primarily by the electrical equipment and appliances used on a feeder. Like the Consumers Energy system, these proprietary solutions are often switched off when feeder reconfiguration occurs.

c. A growing trend is the deployment of "model-driven" Volt-VAR Optimization (VVO) solutions that are incorporated in the electric utility's Advanced Distribution Management System (ADMS). These ADMS solutions perform power flow analysis on an as-switched (as operated) electrical model to determine the "optimal" set of voltage and reactive power control actions to achieve one or more selected operating objectives. Selectable operating objectives may include reduce losses, conserve energy, peak shaving, voltage profile improvement, reactive power support to the bulk power grid, minimize use of high maintenance equipment, or a weighted combination of the above. Besides providing selectable business objectives, model driven solutions can provide the following additional benefits:

    i. The power flow solution automatically provides supplies continuous feedback about the voltage at all points on the feeder so that low or high voltage conditions are rapidly detected and corrected.

    ii. Model-driven solutions adapt automatically when feeder reconfiguration occurs so that CVR does not have to be shut down. While the results for a reconfigured feeder may not represent "optimal" results, they do provide the best possible CVR solution with no voltage deviations given the current as-switched condition of the feeder.

    iii. Model driven solutions are better able to accommodate the impacts of distributed energy resources (DERs) and, where possible, leverage the opportunities offered by DERs, such as using "smart" inverters to supply reactive power. Currently, the DER penetration level is not high enough to warrant consideration of these devices in the CVR system. However, if penetration level rises in the future, a model-driven strategy may be the most effective approach.

    The benefits listed above come at a high price (including implementation costs and O&M costs). However, since Consumers Energy is currently implementing an ADMS that will have the necessary model and application software, a cost-effective model-driven solution may be possible Consumers Energy in the future.

d) Findings, conclusions, and overall assessment of Consumers Energy approach

a. The Consumers Energy SCADA rules-based approach is a very effective solution that has achieved significant Waste Energy Reduction benefits and Peak Demand reductions benefits for Consumers Energy customers and Consumers Energy itself at a reasonable cost.

b. The rules-based approach is well-suited for "proof of concept" as well as achieving actual operational benefits.

c. As discussed above, there are two significant limitations of the rules-based approach used by Consumers Energy: inability to handle feeder reconfiguration and lack of immediate voltage feedback when low voltage conditions occur at some customer meters.

    i. In the future, feeder reconfiguration may occur more frequently than before as Consumers Energy introduces new ADMS applications, such as Fault Location, Isolation, and Service Restoration (FLISR). ESTA assumes that when a feeder is reconfigured for any reason, Consumers Energy will endeavor to restore the feeder to its normal configuration as soon as possible. Therefore, the period that CVR will be disabled is minimized. However, in the long run, Consumers Energy should consider implementing CVR on its new ADMS to avoid a complete shutdown of the CVR application when feeder reconfiguration occurs.

    ii. Due to the lack of near-real-time voltage feedback, a small number of customers may at times experience voltage at the low end of the standard voltage range. Such rare voltage deviations are detected manually by reviewing AMI data the day after a voltage reduction event. Upon detecting the problem, Consumers Energy may alter the CVR settings and, if necessary, plan for infrastructure improvements for more serious and severe problems. This method of low voltage detection is acceptable if the voltage deviation is infrequent, relatively small (less than 2-3% below the minimum voltage) and is promptly corrected. However, failure to deal with severe low voltage conditions on a timely basis can result in customer voltage complaints and, in the worst case, damage to customer-owned equipment.

    This problem can be addressed by adding bellwether voltage meters at feeder extremities and other strategic locations and incorporating measurements from these meters in the CVR logic. This is shown in Figure 5-2 below. If possible, near-real-time low voltage alarms from AMI meters can also be incorporated in the logic. The ADMS model-driven solution provides another possible remedy because the ADMS Powerflow computes the voltage at all feeder locations on a continuous basis and will automatically block control actions that would produce voltage deviations.

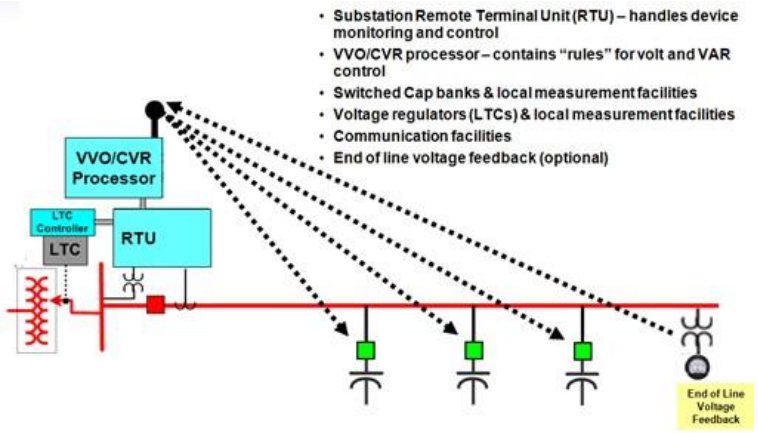


Figure 5-2 Rules-Based CVR with Voltage Feedback

Note that having continuous feedback on feeder voltage level will enable Consumers Energy to operate with a smaller voltage margin to the low voltage threshold, thus enabling Consumers Energy to obtain greater Waste Reduction and Peak Demand reduction benefits.

5.3 CONTROLLED DEVICES

This section contains an assessment of the devices controlled by the Consumers Energy CVR system.

a) General Requirements

The CVR solution should be able to manage the operation of all controllable devices that affect the reactive power flow and voltage profile on the feeder. Controlled devices should include (as a minimum):

i. Voltage regulators located at the head end of the feeder and at mid-line locations (Consumers Energy has few midline regulators on its distribution system and none of these devices on the CVR demonstration feeders)

ii. All switched capacitor banks located out on the feeders.

In the future, the CVR system may need to control additional devices:

iii. ""Edge of network" devices (if any) such as smart inverters and distributed VAR sources located on the secondary side of distribution service transformers.

iv. Distributed energy resources (energy storage, distributed generators with smart inverters, etc.) that are capable of supplying or absorbing real and reactive power on demand.

b) ESTA's understanding of the Consumers Energy approach

a. Consumers Energy CVR system manages the operation of distribution voltage regulators and switched capacitor banks that are installed on the electric distribution system.

b. There are no "Edge of Network" or controllable DERs that are connected to the electric distribution system.

c. Consumers Energy uses separate voltage regulators on all individual feeders. This provides a significant advantage over most other utilities that have multiple feeders connected to a common voltage-controlled substation bus. Consumers Energy can implement different control actions as needed on all feeders out of a single substation without being concerned that a CVR control action will benefit one feeder and adversely impact another feeder that is connected to the same substation. For example, if one substation feeder is voltage limited, it would not be possible to lower the voltage on the remaining feeders connected to the same bus. However, with individual feeder voltage controls, it is possible to lower voltage on feeders that are not voltage limited while retaining the normal voltage or boosting the voltage on the feeder that is voltage limited.

c) Comparison of Consumers Energy approach to best industry practices

The list of controllable volt-VAR devices by Consumers Energy is consistent with devices that are installed on most electric distribution circuits operated by electric distribution utilities.

d) **Findings, conclusions, and overall assessment of Consumers Energy approach**

a. The list of controllable volt-VAR devices on Consumers Energy distribution feeders meets and, in some ways (e.g., control of voltage on individual feeder voltages), exceeds the control requirements for CVR.

b. While Consumers Energy does not currently have any "edge of network" devices, it should be possible to add these devices in the future to either a rules-based solution or ADMS model-driven solution, if needs arise (e.g., widespread electric vehicle charger deployment, addition of significant penetration of rooftop solar PV generators).

5.4 MEASUREMENT DATA COLLECTED

a) General Requirements

a. The CVR system should acquire key measurement data and equipment status information via distribution SCADA or other mechanism on a continuous "near-real-time" basis. In other words, up-to-date field information should be supplied to the CVR system at least once every 15 minutes.

b. Information supplied to the CVR system should include (as a minimum):

i. Real and reactive power flow (A, B, and C phases) measured at the substation end of the feeder.

ii. Voltage measurements (A, B, C phases) at the substation end of the feeder

iii. Voltage measurement at strategic locations on the feeder (e.g., feeder extremities)

iv. Operating status of all equipment that is monitored and controlled by CVR. This includes feeder circuit breaker and recloser status, open/closed position of all capacitor bank switches, and capacitor bank protective devices (e.g., neutral shift detection)

v. Voltage regulator tap position (if available)

c. Data "scrubbing" should be performed to identify and eliminate all data anomalies (e.g., unreasonable values, "stale" information that has not changed for an extended period) in the supplied data. Failure to detect and eliminate these data problems can result in incorrect results.

b) ESTA's understanding of the Consumers Energy approach

a. Consumers provided data from all 50 feeders on which CVR was implemented. On twenty of these feeders, demand response CVR was also conducted on selected peak load days in 2020.

b. List of variables: CVR Status, Timestamp, Phase –X kW Load, Phase –Y kW Load, Phase –Z kW Load, Phase-X secondary load voltage, Phase-Y secondary load voltage, Phase-Z secondary load voltage, Temperature, Total kW Load, Average Sub Voltage

c. Duration: varies for each feeder. "010007" feeder was the first feeder to go under voltage reduction program on August 7, 2019 and "065502" feeder was the last feeder, CVR starting on December 8, 2020. The CVR program continued until April 2021.

d. Resolution: SCADA (Supervisory Control and Data Acquisition) data provided to ESTA was recorded at a 15 min interval.

e. Data Scrubbing: A significant amount of data was scrubbed for several reasons including telemetry issues, Application issues, holidays, and data errors. Scrubbed data was excluded from this analysis.

c) Comparison of Consumers Energy approach to best industry practices

The list of measurement and equipment status information in the Consumers Energy system is consistent with devices that are installed on most electric distribution circuits operated by electric distribution utilities. However, most solutions at other utilities provide a means of obtaining near-real-time voltage feedback from AMI meters or bellwether line voltmeters. Consumers Energy does not receive such voltage feedback on a continuous basis. However, day-after voltage measurements from AMI are reviewed daily by Consumers Energy to detect any voltage problems which are subsequently corrected.

d) **Findings, conclusions, and overall assessment of Consumers Energy approach**

a. The data measurements supplied to the Consumers Energy CVR system provide the minimum amount of information that is needed for operation of the CVR system and for performing M&V of the CVR results.

b. Some data "scrubbing" was needed to eliminate data anomalies, such as "stale" data that remains constant for an extended period. However, enough data remained for performing the M&V after removing suspect data.

c. ESTA notes that the need for data scrubbing during M&V analysis is common in the industry and that the amount of data scrubbing was far less for Consumers Energy's data than the data scrubbing required for M&V purposes at other electric utilities.

d. While Consumers Energy does not currently have any "edge of network" devices, it should be possible to add these devices in the future to either a rules-based solution or ADMS model-driven solution, if needs arise (e.g., widespread electric vehicle charger deployment, addition of significant penetration of rooftop solar PV generators).

5.5 METHOD OF COMPUTING CVR FACTOR

The methods used to compute CVR factor for waste energy reduction and peak demand reduction are slightly different. Therefore, separate sections are provided below for the two operating modes.

5.5.1 CVR FACTOR FOR WASTE ENERGY REDUCTION

a) General Requirements

- M&V analysis must determine the CVR factor for individual distribution feeders with an accuracy of +/- 5% or better. CVR factor is the percentage change in power or energy attributable to voltage reduction divided by the percentage reduction in voltage.

- Separate CVR factors must be provided for Energy Waste reduction and Peak Demand reduction

- Measurement and Verification (M&V) Analysis must separate the electrical impact of voltage reduction on power or energy consumption from other factors that impact power or energy consumption. Other factors include:
  i. Ambient weather conditions and season
  ii. Day of week, time of day

- CVR voltage and load reductions were calculated by averaging all of the day "CVR On"/"CVR Off" readings and comparing the difference.

- $$CVR\ factor = \frac{(Avg.\text{ CVR Off } Load - Avg.CVR\ On\ Load)\ /\ Avg.\text{ CVR Off } Load}{(Avg.\text{ CVR Off } Voltage - Avg.CVR\ On\ Voltage)\ /\ Avg.\text{ CVR Off } Voltage}$$

b) ESTA's understanding of the Consumers Energy approach

- Consumers Energy uses a "Matching Pairs" concept for its CVR M&V analysis. The process involved comparing load measurements for a set of days on which CVR was "on" (voltage reduced) with a set of load measurements for an equal number of days when CVR was "off" (normal voltage applied).

- CVR-On data sets were compared with CVR-Off data sets having "similar" characteristics. "Similar" days are either weekdays or weekends having similar average daily temperatures:

    - **Weekdays versus Weekends:** Data sets containing weekday loads were compared with other weekdays. Weekend days were compared with other weekend days.

    - **Temperature Range:** Each data set contained load data for each "season" which includes days on which the average temperature was within a specified range. Consumers Energy determined the range of seasons based on predetermined temperature thresholds. For example, when mean temperature of the day goes beyond 65 F consistent for consecutive days, "Summer" season is considered to have begun, and it continues till threshold for "Fall" season is reached. Based on this following season ranges were identified: Start Day, End Day
        i. 2019 Summer: 8/7 to 10/1
        ii. 2019 Fall: 10/2 to 11/5
        iii. 2019/2020 Winter: 11/6 to 3/24
        iv. 2020 Spring: 3/25 to 5/22
        v. 2020 Summer: 5/23 to 9/6
        vi. 2020 Fall: 9/7 to 11/20
        vii. 2020/2021 Winter: 11/21 to 3/9

.

- Each CVR On day has a corresponding CVR Off day with the same day type (weekday or weekend) and season. An equal number of CVR On days and CVR Off days is needed for this analysis. If the number of days in each category is not the same, the M&V algorithm will exclude days from the category with higher number of days by first taking the mean load and temperature of each day and whole day and season category and eliminate the day with mean farthest from category mean.

- Once the CVR on-off cycle is completed, the load and voltage value are collected for each feeder over a resolution of 15 mins. The CVR factor is calculated by averaging all days with "CVR On"/"CVR Off" readings and comparing the difference, as shown below:

$$CVR\ factor = \frac{(Avg.\text{ CVR Off } Load - Avg.\ CVR\ On\ Load) \Big/ Avg.\text{ CVR Off } Load}{(Avg.\text{ CVR Off } Voltage - Avg.\ CVR\ On\ Voltage) \Big/ Avg.\text{ CVR Off } Voltage}$$

- Using this calculation, Consumers Energy found that from date 8/7/2019 to 12/31/2020, for all the CVR experiments conducted on all 50 feeders, the average CVR factor they were able achieve

was 0.82, with it ranging from 1.34 to 0.07. The average voltage drop was 2.31%, while the average load drop was 1.9%.

- The Consumers Energy M&V approach assumes that the primary factors other than voltage that affect the average load on a given feeder are day of week (i.e., weekday versus weekend, holidays excluded), average ambient temperature, and season.

- Based on this assumption, the loading on a selected feeder will be the same on all weekdays in each season that have the same daily average temperature if the voltage is the same. For example, the loading on a selected feeder for two summer weekdays (Monday through Friday) that have the same average temperature will be approximately the same if normal voltage is supplied to the feeder.

- As a result of the assumptions listed above, any loading difference on two summer days with the same average temperature can be attributed to differences in applied voltage.

- To compute the CVR factor for a given feeder, Consumers Energy performed the following tasks:

    - Defined seasons as a consecutive set of days where daily average temperature is within a given range, and created separate files containing load and voltage data for each season.

    - Separated the above seasonal data files into two files: one containing only weekdays (Monday through Friday) and one containing only Weekends (Saturday and Sunday). Loading for special days and holidays was excluded from the analysis.

    - Separated the weekday file and the weekend file into two files: one file contains only loading data when voltage was reduced (CVR on) and one file containing loading data when voltage was not reduced.

    - The next step in the process was to ensure that number of “CVR On” days in each season’s weekday file is the same as the number of “CVR Off” days in each season’s weekday file.

    - Consumers Energy then computed the average daily load and the average voltage using data in the “CVR On” file and the average daily load and voltage using data from the “CVR Off” file. Then Consumers Energy computed the percentage difference in average daily load and average voltage between the On days and Off days

    - The CVR factor for the feeder in the given season is the percentage difference in feeder loading for CVR On and CVR Off days divided by the percentage difference in average voltage for CVR On days and CVR off days.

- CVR factors were computed as described above for each of the fifty feeders in the CVR demonstration. The results are shown in . As seen in T 5-6, CVR factor varied from feeder to feeder ranging from 0.07 to 1.34, with the average CVR factor for this group of feeders being 0.82.

- In 2021, Consumers Energy plans to use a new Predictive software tool called MetrixND to forecast what the load "would have been" had voltage not been reduced (i.e., normal voltage applied). Consumers Energy plans to use this load forecasting tool to derive a CVR factor for each tested circuit.

Table 5-6 CVR Factors for Each Feeder using "Matching Pairs" Method

Feeder ID	Substation	Circuit	CVR Enabled Date	Consumers CVRf
1903	Roberts Street	Bender	6/10/2020	0.99
7303	Milton	Federal Screw	1/22/2020	0.86
10007	Wealthy Street	Godfrey	8/7/2019	0.79
10106	Fremont	Reeman	11/6/2019	0.70
14301	Spring Lake	Spring Lake	3/4/2020	0.79
17301	Meridian	Towar Gardens	10/9/2019	0.87
21801	Wildwood	Yardman	5/27/2020	0.41
21802	Wildwood	Macklin	11/20/2019	1.16
23508	Beals Road	Godwin Heights	1/15/2020	0.82
28802	Michigan Center	Ballard	5/13/2020	0.90
29203	Manchester	Duncan	5/14/2020	1.34
29901	Norton	Pontaluna Road	1/22/2020	1.06
29902	Norton	Hile Road	5/13/2020	1.31
31803	East Muskegon	Quarterline Road	2/12/2020	0.84
34201	Hickory	Gateway	1/29/2020	0.07
34401	Hull Street	Lime Lake	11/13/2019	0.86
36902	Cooley	North Street	3/18/2020	0.75
41303	Terrace	Spring	10/23/2019	0.74
43502	Lake Odessa	Industrial	8/21/2019	0.72
48301	Aubil Lake	Towers	5/20/2020	0.78
50403	Oliver	King Street	1/8/2020	0.59
56802	Ramona	Blodgett	10/30/2019	0.49
60701	Getty	Marquette	6/3/2020	1.13
63403	Kilgore	Mount Everest	6/10/2020	0.99
63404	Kilgore	Timberlane	2/5/2020	0.88
63802	Neeley	Doster	5/27/2020	0.94
65502	O-at-ka	East Bay	8/12/2020	1.29
69902	Walker	Rosalie	2/12/2020	0.82
70305	Ingham	Greenwood Park	7/2/2020	1.24
72702	Burlingame	Michael	2/5/2020	0.82

73101	Mona Lake	Airport	3/18/2020	0.82
81502	Harper Road	Eifert	6/24/2020	1.33
90701	Club	Adventure	5/20/2020	0.63
90802	Oak Street	West Ganson	1/15/2020	0.66
101902	Midway	Naomi	1/8/2020	0.59
102701	Savidge	Boom Road	3/4/2020	0.74
110802	Williams	Cresent	2/19/2020	0.81
118401	Newburg	Bancroft	8/14/2019	0.92
118403	Newburg	Shiatown	5/20/2020	0.63
128802	Bennett	Jolly Road	5/27/2020	0.43
128803	Bennett	Dobie Road	2/19/2020	0.76
130301	West Road	Wood Road	3/11/2020	0.84
133501	Tallman	Wacousta	6/3/2020	1.34
133502	Tallman	Clark Road	10/16/2019	0.73
148501	Crahen	Greenbrier	5/14/2020	0.54
149502	Eleventh Street	Starr Road	6/17/2020	0.76
150002	Withey Lake	Henderson	6/17/2020	0.63
154301	Harvard Lake	Harvard Lake	6/3/2020	0.79
154901	Birchwood	Laraway Lake	3/11/2020	0.67
157802	Tremaine	Keefer Road	1/29/2020	0.56
Total				**0.82**

c) Comparison of Consumers Energy approach to best industry practices

- Regression Analysis of Day-On/Day-Off data
  - The CVR M&V approach that is most widely used in the electric utility industry involves multiple regression analysis to determine the relationship between various independent variables that typically impact load (ambient temperature, day of week, voltage level, etc.) and load.
  - The analysis is applied to data collected during CVR Day-On/Day-Off or CVR week on/week off demonstrations like the CVR pilot demonstrations conducted by Consumers Energy.
  - The resulting regression formula is used to estimate what the feeder load "would have been" on a "CVR On" day (reduced voltage) if the voltage had not been reduced.
  - The CVR factor can then be determined by comparing the actual measured loads for CVR On days against the estimated load computed using the regression formula.
- ESTA performed a regression analysis as described above using the day-on/day-off data supplied by Consumers Energy. The results of this analysis are summarized in Table 5-7 below. The CVR

factors computed using regression analysis and the Consumers Energy "matching pairs" approach was somewhat different for individual feeders. The CVR factors computed for individual feeders using regression analysis ranged from 0.2 to 1.41 (compared with the range of .07 to 1.34 for matching pairs). However, the overall average CVR factor for the entire set of CVR feeders computed using the two approaches was similar: 0.77 to regression analysis and 0.82 for matching pairs. Note that the regression analysis performed by ESTA has a modelling error of +/- 3.7%. So the range of the regression analysis is 0.74 to 0.79.

- ESTA finds that the results obtained using the two independent and significantly different approaches are comparable and consistent with results published by other electric utilities. As a result, ESTA concludes that the approach used by Consumers Energy for computing the CVR factors for Waste Energy Reduction is valid and accurate.

Table 5-7 Comparison of Feeder CVR Factors Using Matching Pairs and Regression Analysis

Feeder ID	Substation	Circuit	CVR Enabled Date	Consumers CVRf	Model Error Rate	Model CVRf	Difference
1903	Roberts Street	Bender	6/10/2020	0.99	5.49%	1.13	14%
7303	Milton	Federal Screw	1/22/2020	0.86	4.10%	0.65	25%
10007	Wealthy Street	Godfrey	8/7/2019	0.79	3.27%	0.7	11%
10106	Fremont	Reeman	11/6/2019	0.70	3.19%	0.56	20%
14301	Spring Lake	Spring Lake	3/4/2020	0.79	3.81%	1.01	28%
17301	Meridian	Towar Gardens	10/9/2019	0.87	4.42%	0.97	12%
21801	Wildwood	Yardman	5/27/2020	0.41	3.84%	0.27	34%
21802	Wildwood	Macklin	11/20/2019	1.16	3.72%	0.83	28%
23508	Beals Road	Godwin Heights	1/15/2020	0.82	3.95%	1.08	31%
28802	Michigan Center	Ballard	5/13/2020	0.90	4.08%	1	11%
29203	Manchester	Duncan	5/14/2020	1.34	4.07%	1.03	23%
29901	Norton	Pontaluna Road	1/22/2020	1.06	3.06%	1.24	17%
29902	Norton	Hile Road	5/13/2020	1.31	3.94%	1.3	1%
31803	East Muskegon	Quarterline Road	2/12/2020	0.84	3.53%	0.81	4%
34201	Hickory	Gateway	1/29/2020	0.07	4.21%	0.21	202%
34401	Hull Street	Lime Lake	11/13/2019	0.86	4.26%	1.09	27%
36902	Cooley	North Street	3/18/2020	0.75	2.92%	0.66	12%
41303	Terrace	Spring	10/23/2019	0.74	2.95%	0.74	0%
43502	Lake Odessa	Industrial	8/21/2019	0.72	3.29%	0.74	2%
48301	Aubil Lake	Towers	5/20/2020	0.78	4.84%	0.71	9%
50403	Oliver	King Street	1/8/2020	0.59	3.82%	0.46	22%
56802	Ramona	Blodgett	10/30/2019	0.49	2.12%	0.42	15%
60701	Getty	Marquette	6/3/2020	1.13	3.65%	0.81	28%

63403	Kilgore	Mount Everest	6/10/2020	0.99	3.81%	0.5	50%
63404	Kilgore	Timberlane	2/5/2020	0.88	4.28%	0.53	39%
63802	Neeley	Doster	5/27/2020	0.94	4.33%	0.9	4%
65502	O-at-ka	East Bay	8/12/2020	1.29	3.21%	0.75	42%
69902	Walker	Rosalie	2/12/2020	0.82	3.33%	0.99	21%
70305	Ingham	Greenwood Park	7/2/2020	1.24	3.12%	0.65	47%
72702	Burlingame	Michael	2/5/2020	0.82	3.45%	0.51	37%
73101	Mona Lake	Airport	3/18/2020	0.82	3.55%	0.8	2%
81502	Harper Road	Eifert	6/24/2020	1.33	5.94%	0.99	25%
90701	Club	Adventure	5/20/2020	0.63	4.39%	0.66	6%
90802	Oak Street	West Ganson	1/15/2020	0.66	3.35%	0.71	8%
101902	Midway	Naomi	1/8/2020	0.59	3.67%	0.2	66%
102701	Savidge	Boom Road	3/4/2020	0.74	3.84%	0.42	43%
110802	Williams	Cresent	2/19/2020	0.81	3.59%	0.73	10%
118401	Newburg	Bancroft	8/14/2019	0.92	3.03%	0.71	23%
118403	Newburg	Shiatown	5/20/2020	0.63	3.93%	0.69	9%
128802	Bennett	Jolly Road	5/27/2020	0.43	4.50%	0.88	106%
128803	Bennett	Dobie Road	2/19/2020	0.76	3.26%	0.64	16%
130301	West Road	Wood Road	3/11/2020	0.84	3.46%	0.32	62%
133501	Tallman	Wacousta	6/3/2020	1.34	6.28%	1.09	19%
133502	Tallman	Clark Road	10/16/2019	0.73	4.37%	0.6	18%
148501	Crahen	Greenbrier	5/14/2020	0.54	3.85%	0.84	54%
149502	Eleventh Street	Starr Road	6/17/2020	0.76	4.33%	1.07	40%
150002	Withey Lake	Henderson	6/17/2020	0.63	5.33%	1.41	124%
154301	Harvard Lake	Harvard Lake	6/3/2020	0.79	4.47%	0.92	16%
154901	Birchwood	Laraway Lake	3/11/2020	0.67	3.48%	0.61	9%
157802	Tremaine	Keefer Road	1/29/2020	0.56	4.29%	0.88	57%
Total				**0.82**	**3.90%**	**0.77**	**31%**

- Neural Net Methodology

  - ESTA has used neural net methodology to compute CVR factors with an accuracy of 2% or better, However, this method requires several years of data to "train" a model that is used to predict what the load would have been on a future date if voltage had not been reduced. Note that this approach may not be possible at this time for Consumers Energy because the CVR pilot projects have been conducted during the pandemic, which has exhibited considerably different loading patterns due to work-at-home restrictions.

d) Findings, conclusions, and overall assessment of Consumers Energy approach

a. ESTA has reviewed the Consumers Energy "Matching Pairs" M&V method and offers the following comments and conclusions.

b. A major assumption on which the "Matching Pairs" analysis is based is that differences in average feeder loading observed in the day-on and day-off data sets are primarily due to voltage differences rather than differences in ambient temperature. For this assumption to be valid, the load must remain nearly constant with normal voltage applied for the days in each season.

c. ESTA examined the relationship between load and ambient temperature and observed the expected relation between load and temperature for Consumers Energy CVR feeders. Figure 5-3 contains graph showing the relationship between load and ambient temperature for one of the Consumers Energy feeders in the Selected CVR feeders. As expected, the relationship is a bathtub shaped curve with sloping lines that are different for each feeder. ESTA used the bathtub curve sloping lines for each feeder to determine the approximate change of load given the range of ambient temperatures observed.

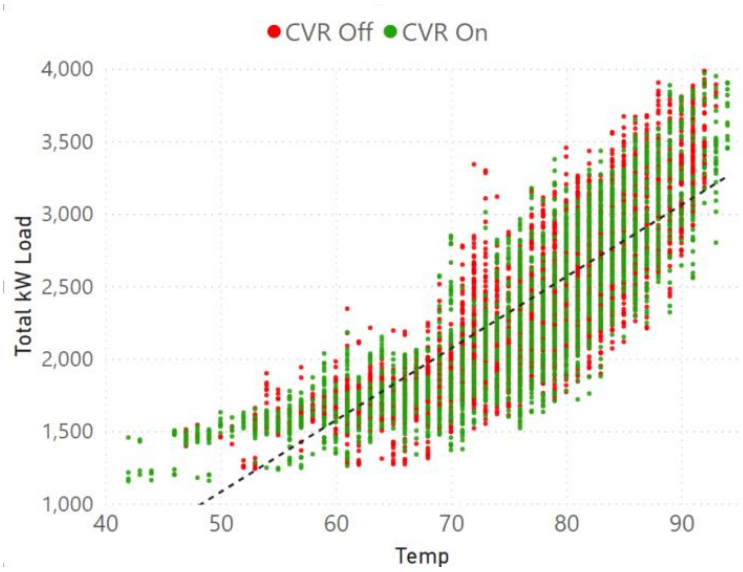


Figure 5-3 Variation of Load with Temperature on a CVR feeder

d. The results showed that for most feeders, the feeder load changed by only a small percentage amount for the range of temperatures included in the "seasonal" data sets. Table 5-8 shows the approximate change in load that can be attributed to the temperature differences in the matching pairs data sets for weekdays in summer. Hence, ESTA concludes that average load variations in the Day-On and Day-Off datasets are primarily due to voltage reduction. This is shown in the table below for summer weekdays:

Table 5-8 Expected Change in Weekday Load for Temperature Variation in Summer

Feeder ID	Day Type	CVR Temp On	CVR Temp Off	Load Change per F	Load variation due to Temp
1903	Weekday	72.75	72.95	1.20%	-0.25%
1903	Weekend	69.93	72.28	1.21%	-2.83%
7303	Weekend	62.93	62.02	0.45%	0.41%
7303	Weekday	64.03	62.32	-0.08%	-0.14%
10007	Weekday	73.40	72.95	1.60%	0.71%
10007	Weekend	71.72	70.96	1.80%	1.35%
10106	Weekend	63.85	64.49	0.76%	-0.48%
10106	Weekday	68.05	65.97	0.49%	1.02%
14301	Weekend	71.96	71.53	3.06%	1.31%
14301	Weekday	74.25	74.09	3.16%	0.51%
21801	Weekday	72.67	73.19	1.95%	-1.00%
21801	Weekend	70.78	70.45	2.42%	0.80%
21802	Weekend	70.16	70.08	3.07%	0.24%
21802	Weekday	72.87	73.44	2.99%	-1.71%
23508	Weekend	71.41	71.82	1.97%	-0.81%
23508	Weekday	73.18	73.47	1.39%	-0.40%
28802	Weekend	70.48	70.66	3.15%	-0.55%
28802	Weekday	72.72	73.05	3.17%	-1.06%
29203	Weekend	64.99	64.81	0.86%	0.16%
29203	Weekday	70.16	67.62	0.69%	1.75%
29901	Weekend	67.19	70.77	1.93%	-6.91%
29901	Weekday	71.35	71.19	3.19%	0.53%
29902	Weekend	71.77	72.13	3.30%	-1.20%
29902	Weekday	73.54	73.89	3.55%	-1.26%
31803	Weekend	71.85	71.53	2.43%	0.78%
31803	Weekday	74.09	73.99	2.68%	0.26%
34201	Weekend	73.97	66.21	1.57%	12.18%
34201	Weekday	73.97	75.11	0.81%	-0.92%
34401	Weekend	72.47	72.14	2.91%	0.94%
34401	Weekday	73.75	74.20	2.78%	-1.26%
36902	Weekend	73.30	72.43	2.40%	2.10%
36902	Weekday	75.73	75.54	2.18%	0.41%
41303	Weekend	71.95	70.55	2.13%	2.98%
41303	Weekday	73.92	73.75	2.09%	0.34%
43502	Weekend	64.03	67.83	0.83%	-3.16%
43502	Weekday	65.77	66.23	0.40%	-0.19%
48301	Weekend	71.56	71.20	2.80%	0.99%
48301	Weekday	73.83	74.05	2.54%	-0.56%
50403	Weekend	63.91	64.08	0.53%	-0.09%
50403	Weekday	65.73	64.38	0.27%	0.36%

56802	Weekend	72.09	71.36	1.58%	1.16%
56802	Weekday	74.47	74.73	1.49%	-0.40%
60701	Weekday	71.31	70.41	2.11%	1.89%
60701	Weekend	68.43	71.97	2.28%	-8.10%
63403	Weekday	75.79	75.81	2.93%	-0.04%
63403	Weekend	74.24	75.15	3.04%	-2.78%
63404	Weekend	73.17	74.80	2.15%	-3.50%
63404	Weekday	75.19	76.15	2.16%	-2.08%
63802	Weekday	75.20	75.85	3.17%	-2.06%
63802	Weekend	72.98	73.45	3.01%	-1.40%
65502	Weekday	71.83	73.15	2.56%	-3.38%
65502	Weekend	67.69	70.88	2.41%	-7.69%
69902	Weekend	71.50	70.96	3.07%	1.65%
69902	Weekday	73.47	74.26	3.23%	-2.57%
70305	Weekday	73.03	73.80	1.70%	-1.31%
70305	Weekend	69.03	74.03	1.91%	-9.54%
72702	Weekend	71.46	71.79	2.74%	-0.92%
72702	Weekday	73.75	74.02	2.89%	-0.78%
73101	Weekend	71.96	71.53	2.95%	1.27%
73101	Weekday	74.22	74.09	3.13%	0.42%
81502	Weekday	72.71	72.89	2.37%	-0.43%
81502	Weekend	70.35	73.21	2.05%	-5.87%
90701	Weekday	74.82	73.83	2.67%	2.65%
90701	Weekend	73.01	72.59	2.45%	1.01%
90802	Weekend	70.48	70.66	2.18%	-0.38%
90802	Weekday	72.72	73.07	1.91%	-0.69%
101902	Weekend	72.57	72.41	2.23%	0.34%
101902	Weekday	75.59	75.54	2.64%	0.14%
102701	Weekend	71.96	71.53	2.52%	1.08%
102701	Weekday	74.25	74.09	2.19%	0.36%
110802	Weekend	65.83	64.66	0.61%	0.72%
110802	Weekday	64.77	67.25	0.35%	-0.88%
118401	Weekday	67.75	68.39	0.80%	-0.52%
118401	Weekend	64.39	64.74	0.73%	-0.26%
118403	Weekend	63.90	63.43	0.81%	0.38%
118403	Weekday	65.21	64.50	0.58%	0.41%
128802	Weekday	64.92	66.61	0.51%	-0.86%
128802	Weekend	64.53	63.90	0.84%	0.53%
128803	Weekend	64.35	63.33	0.86%	0.88%
128803	Weekday	64.06	65.91	0.56%	-1.04%
130301	Weekend	71.26	70.54	2.46%	1.76%
130301	Weekday	73.31	73.35	2.71%	-0.10%
133501	Weekday	75.40	74.64	4.50%	3.40%

133501	Weekend	74.51	73.13	4.79%	6.61%
133502	Weekend	72.39	70.55	3.02%	5.56%
133502	Weekday	73.90	73.58	3.22%	1.03%
148501	Weekend	71.55	70.51	1.93%	2.00%
148501	Weekday	73.71	73.71	1.93%	0.01%
149502	Weekday	76.66	77.06	2.82%	-1.14%
149502	Weekend	77.70	75.85	3.16%	5.86%
150002	Weekday	72.06	71.44	2.33%	1.44%
150002	Weekend	73.65	71.37	1.94%	4.44%
154301	Weekday	74.23	73.66	3.15%	1.77%
154301	Weekend	73.18	73.21	2.97%	-0.07%
154901	Weekend	71.45	71.64	2.66%	-0.48%
154901	Weekday	74.06	73.96	2.83%	0.29%
157802	Weekend	64.52	61.46	0.70%	2.15%
157802	Weekday	57.99	61.51	0.22%	-0.76%

e. Since the matching pair data set loading differences are primarily due to voltage reduction, ESTA believes it is acceptable and valid to use Consumers Energy's averaging technique to determine CVR factors.

f. The overall average CVR factor for the CVR feeders computed using Consumers Energy Matching Pair approach compares favorably with the overall average computed using regression analysis. ESTA believes this further confirms the approach. Significant differences in the results for individual feeders is attributable to the small number of data samples.

5.5.2 CVR FACTOR FOR PEAK DEMAND REDUCTION

This section describes the approach used for computing the Peak Demand reduction benefits. This approach is slightly different than the previously described procedure for computing the Energy Waste Reduction benefits.

a) General Requirements

a. Measurement and Verification (M&V) analysis must determine the CVR factor for individual distribution feeders with an accuracy of +/- 5% or better. CVR factor is the percentage change in power or energy attributable to voltage reduction divided by the percentage change in voltage.

b. Separate CVR factors must be provided for Energy Waste reduction and peak demand reduction.

c. Measurement and Verification (M&V) Analysis must separate the electrical impact of voltage reduction on power or energy consumption from other factors that impact power or energy consumption. Other factors include:
   i. Ambient weather conditions and season
   ii. Day of week, time of day

d. CVR voltage and load reductions were calculated by averaging all of the day "CVR On"/"CVR Off" readings and comparing the difference.

e. $$CVR\ factor = \frac{(Avg.\ \text{CVR Off}\ Load - Avg.CVR\ On\ Load)\ /\ Avg.\ \text{CVR Off}\ Load}{(Avg.\ \text{CVR Off}\ Voltage - Avg.CVR\ On\ Voltage)\ /\ Avg.\ \text{CVR Off}\ Voltage}$$

b) ESTA's understanding of the Consumers Energy approach

- The method used by Consumers Energy for computing the CVR factor for peak demand reduction is very similar to the method described above. Consumers Energy assumed the CVR factor obtained above would be the same for peak demand reduction as waste energy reduction. Then the peak demand reduction was calculated as follows:

$$Peak\ Demand\ Reduction = CVR\ Factor\ for\ waste\ energy\ reduction \times Voltage\ Reduction$$

- In 2021, Consumers Energy plans to use "MetrixND", a predictive software tool from ITRON to determine the CVR factor for Peak Shaving reduction. The analysis performed by this software tool is like the regression analysis ESTA used for determining a CVR factor for peak shaving reduction (see next Section). This software determines what the peak load "would have been" during a Peak Demand reduction event if normal voltage had been applied instead of reduced voltage. Consumers Energy plans to use measurements of the following independent variables to perform this analysis:
  - Solar irradiation and hours of sunlight on a given day.
  - Loading on recent past days
  - Dry Bulb temperature

c) Comparison of Consumers Energy approach to best industry practices

- Regression Analysis of Day-On/Day-Off data
  - The CVR M&V approach that is most widely used in the electric utility industry involves multiple regression analysis to determine the relationship between various independent variables that typically impact load (ambient temperature, day of week, voltage level, etc.) and load.
  - The analysis is applied to data collected during CVR Day-On/Day-Off demonstrations like the CVR pilot demonstrations conducted by Consumers Energy.
  - The resulting regression formula is used to estimate what the feeder load "would have been" on a "CVR On" day (reduced voltage) if the voltage had <u>not</u> been reduced.
  - The CVR factor can then be determined by comparing the actual measured loads for CVR On days against the estimated load computed using the regression formula.

- ESTA performed a regression analysis as described above using the day-on/day-off load data and average ambient temperature data supplied by Consumers Energy. The objective of this analysis is to determine what "would have happened" if voltage had not been reduced on the DR day in question.

- This model is trained using data when CVR status is "CVR off". This model uses inputs like voltage, temperature, heating and cooling days and temporal features like hour of the day and season. This model can account for temperature and customer behavior variations and is found to have an average error rate of 3.76%. This trained model is then used on "CVR On" hours of each feeder and demand response day to predict what the load would have been for the hours when CVR was on, if mean voltage instead of reduced voltage was applied. This predicted load is then compared with actual load to compute a mean CVR factor.

- Consumers followed a pre-determined peak reduction schedule as mentioned below:

Table 5-9 Peak Reduction Schedule

DR Date	DR Time Range	Feeder IDs
7/1/2020	1400 - 1500	050403,
7/2/2020	1400 - 1500	072702,
7/8/2020	1400 - 1600	056802, 133502, 154901
7/9/2020	1400 - 1600	090701, 041303, 007303
7/15/2020	1400 - 1700	148501, 081502, 118401, 118403, 017301
7/16/2020	1400 - 1700	128803, 034401, 110802, 157802, 149502
7/22/2020	1400 - 1800	150002, 043502, 072702, 056802, 133502, 154901, 128803, 034401, 110802, 157802, 149502
7/23/2020	1400 - 1800	050403, 090701, 041303, 007303, 148501, 081502, 118401, 118403, 017301
7/29/2020	1400 - 1800	050403, 090701, 041303, 007303, 148501, 081502, 118401, 118403, 017301
7/30/2020	1400 - 1800	150002, 043502, 072702, 056802, 133502, 154901, 128803, 034401, 110802, 157802, 149502
8/5/2020	1400 - 1800	050403, 090701, 041303, 007303, 148501, 081502, 118401, 118403, 017301
8/6/2020	1400 - 1800	150002, 043502, 072702, 056802, 133502, 154901, 128803, 034401, 110802, 157802, 149502

- Regression model is used for each of the feeder on each CVR Date along the time range mentioned in above table to predict load without CVR. Using this a CVR factor is calculated for each instance as follows:

$$CVR\ Factor = \frac{(Avg.\text{ Predicted } Load - Avg.\ CVR\ On\ Load)\Big/ Avg.\text{ Predicted } Load}{(Avg.\text{ CVR Off } Voltage - Avg.\ CVR\ On\ Voltage)\Big/ Avg.\text{ CVR Off } Voltage}$$

Based on this formula an average CVR factor of 1.51 is computed for all feeders on all Demand response days. As mentioned above average error rate of regression model was 3.86% so ESTA can claim that CVR factor should lie with $\pm$3.86% of 1.51 or between 1.45 and 1.56.

- The results of this analysis were compared with Peak Demand Reduction CVR factor computed by ESTA for another electric utility (utility name confidential). As seen in Figure 5-4, the Peak demand was reduced 600kW (6.5%) during a 4-hour, 15-minute voltage reduction of 4.5%. The Peak Demand CVR factor for this utility was 1.45 (6.5% / 4.5%). This is consistent with the results obtained by ESTA for Consumers Energy.

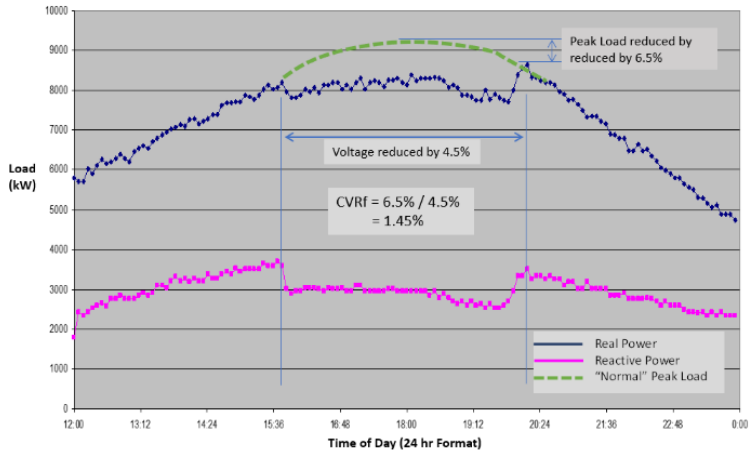


Figure 5-4 Results of Peak Demand CVR

d) Findings, conclusions, and overall assessment of Consumers Energy approach

a. ESTA has reviewed the Consumers Energy "Peak Demand Reduction" M&V method and offers the following comments and conclusions.

b. An average CVR factor of 1.51 is computed for all feeders on all Demand response days. As mentioned above average error rate of regression model was +/- 3.89% so that the CVR factor should lie with of 1.51 or between 1.45 and 1.57

c. Table 5-10 below shows the average Peak demand CVR factor that ESTA computed for each Consumers Energy feeder on all demand response days.

Table 5-10 Peak Demand CVR factors for Individual feeders

Feeder ID	Model Error Rate	CVR Factor
7303	4.10%	1
34401	4.26%	3.73
41303	2.95%	0.65
43502	3.29%	0.69
50403	3.82%	1.61
56802	2.12%	1.32
72702	3.45%	1.91
81502	5.94%	0.33
90701	4.39%	1.11
110802	3.59%	1.71
118401	3.03%	1.45
118403	3.93%	0.89
128803	3.26%	1.35
133502	4.37%	1.31
148501	3.85%	2.92
149502	4.33%	2.54
150002	5.33%	2.5
154901	3.48%	1.07
157802	4.39%	0.6
Average	**3.89%**	**1.51**

d. Figure 5-5 below shows the average effect of peak demand reduction for all feeders.

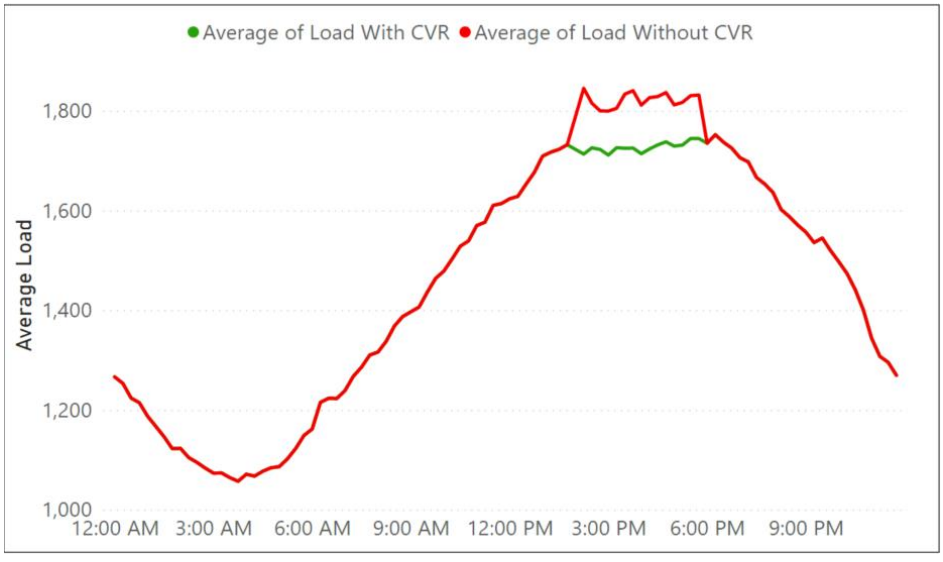


Figure 5-5 Average Peak Demand CVR Factor For Consumers Energy

6 SUMMARY OF FINDINGS CONCLUSIONS AND RECOMMENDATIONS

Following is a summary of ESTA's major findings, conclusions, and recommendations resulting from this assessment:

- **Feeder Selection:** As stated earlier in this report, the approach used by Consumers Energy to select feeders for its CVR Demonstration project far exceeds the feeder selection approach used by many other utility companies (based on ESTA experience).
    - Key characteristics of the CVR demonstration feeders selected by Consumers Energy match the characteristics of the broader set of "CVR Proposed" feeders on which CVR may be implemented in the future. While some characteristics are not the same, customer mix is very similar between the two groups. ESTA considers this to be one of the most important factors that determines the CVR factor for a given feeder.
    - As a result, ESTA believes that the selected CVR feeders represent the broader community of Consumers Energy feeders on which CVR is likely to be implemented.
    - In ESTA's opinion, it is acceptable to assume that the results obtained for the initial 50 feeders can be applied to future CVR feeders selected from the CVR Proposed feeder set.
- **CVR Solution:** The Consumers Energy CVR solution is a DSCADA rules-based solution, meaning a set of predetermined rules involving the application of Boolean logic to measurements acquired by the distribution SCADA system.
    - Most of the CVR solutions that have been successfully implemented by North American electric distribution systems are rules-based systems like what has been implemented by Consumers Energy. While this approach has some limitations, such as inability to adapt automatically to feeder reconfiguration, the approach has the benefit of simplicity, ease of operating and maintenance, and cost effectiveness, while providing the expected benefits.
    - Shortcomings of the existing approach include:
        - Lack of immediate voltage feedback to alert system operators to low or high voltage conditions on the feeder. Currently, such events may be detected the next day through manual review of voltage records from AMI. This approach is generally acceptable if major voltage deviations (e.g., voltage dips well below lower ANSI C84.1 limit) do not routinely occur.
        - Inability to adapt automatically to changing feeder configuration. Currently, Consumers Energy disables CVR if the feeder is reconfigured. While not the preferred approach, disabling CVR is acceptable if this is for a short duration (i.e., normal feeder configuration restored as quickly as possible),

- In the future, Consumers Energy should consider implementing model-driven VVO on its new ADMS. This should eliminate the shortcomings listed above.

- **Controlled Devices**

  - Consumers Energy controls switched capacitor banks and voltage regulators on its feeders. Within the industry, this is the most common complement of controlled equipment.

  - In the future, additional control requirements may apply. Examples include smart inverters and distributed generators. If these new requirements emerge at Consumers Energy, and ADMS-based, model-driven solution may be required due to the impracticality of handling these requirements with fixed Boolean logic.

- **Measurement data**

  - The measurements and equipment status information acquired by Consumers Energy for CVR purposes is adequate for meeting the basic needs of this application.

  - Some "scrubbing" was needed to eliminate questionable data (such as "stale" data measurements) collected during the CVR demonstration project. However, it is noted that data scrubbing is typically required on all M&V projects of this type, and that the amount of data scrubbing for Consumers Energy was far less than other M&V projects done by ESTA.

  - Adding near-real-time voltage measurements or low/high voltage alarms from AMI or bellwether meters would be beneficial, especially for heavily loaded feeders that are routinely operated close to the industry limits. Adding voltage feedback will enable Consumers Energy to gain additional benefits by operating with small margins (closer to voltage limits).

- **Approach to Measurement and Verification and Results Obtained**

  - The Matching Pairs M&V approach is relatively easy to understand and implement, compared to other advanced techniques (such as regression analysis and neural network modelling). As a result, it is possible to cross check the results using simple averaging to confirm the results. Another advantage is the ability to gain acceptance of the results by decision makers who do not have an advanced mathematical and statistical background.

  - ESTA performed an M&V analysis on the Consumers Energy data using multiple regression analysis that included consideration of loading, voltage, and ambient temperature. Regression analysis is the most widely used approach in the electric utility industry for CVR M&V.

  - The overall average CVR factor for the CVR feeders computed using Consumers Energy Matching Pair approach is 0.82, which compares favorably with the overall average computed using

regression analysis (0.77 +/- 3.7%). We believe this further confirms the approach. Significant differences in the results for individual feeders is attributable to the small number of data samples.

- ESTA concludes that the results obtained by Consumers Energy during its CVR demonstration and analysis are valid and representative of results than can be received by implementing CVR on the CVR Proposed data set.

- ESTA computed a CVR factor for Peak Demand reduction using regression analysis to determine what "would have happened" during peak load conditions if normal voltage were applied on Demand Response days when CVR Peak Demand reduction occurred. The result of this analysis was a Peak Demand Reduction CVR factor of 1.56 +/- 3.86% on average for the 20 feeders on which Peak Reduction CVR was applied.

- Consumers Energy has assumed that the CVR factor for Peak Demand reduction is the same (0.82) as the CVR Factor for Waste Energy Reduction, which is a very conservative assumption compared to the results computed by ESTA. Based on the results of ESTA's Peak demand CVR analysis and the results at one other electric utility (undisclosed), the results are considerably higher than the CVR factor for peak demand reduction assumed by Consumers Energy. The main reason for this difference is that the complement of equipment and appliances running during daily peak load hours is considerably different than the equipment complement running on average. For example, the amount of air conditioning load during peak load hours on a hot summer day is likely to be significantly higher than the average AC load for the day.

In 2021, Consumers Energy plans to use "MetrixND", a predictive software tool from ITRON to determine the CVR factor for Peak Shaving reduction. The analysis performed by this software tool is like the regression analysis ESTA used for determining a CVR factor for peak shaving reduction. In ESTA's opinion, this approach will yield much more accurate results for the Peak Demand CVR factor than the current conservative approach. ESTA strongly recommends that Consumers Energy use this approach for future analysis of peak demand CVR reduction.

Appendix A CVR BACKGROUND INFORMATION

A.1 VOLTAGE REDUCTION

As electric utilities seek to address energy efficiency and conservation portfolios, many electric distribution utilities are turning to voltage reduction to satisfy energy efficiency, demand reduction, and energy conservation objectives. Voltage reduction involves operating the distribution feeder at a voltage that is in the lower portion of the acceptable voltage range (See Figure 6-1). Electric utility experience, backed by extensive laboratory testing, has shown that many electrical loads, especially electric motors, consume less real and reactive power and perform just as well (or better) when voltage is lowered slightly. When voltage reduction is performed whenever possible (up to 24 hours per day, seven days per week), this is called "Conservation Voltage Reduction". This is because 24-hour-per-day operation is primarily intended to promote energy conservation. If voltage reduction is used only during peak load periods for purposes of peak shaving, the term voltage reduction (VR) or voltage optimization is commonly used.

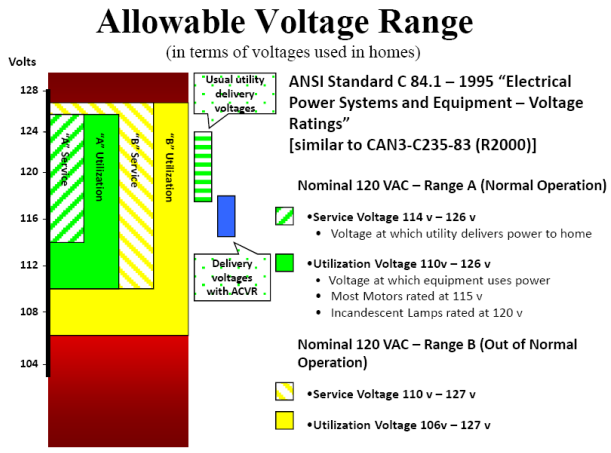


Figure 6-1 Allowable Voltage Range (per ANSI C84.1)

Many electric utilities and their associated grid management authority have used voltage reduction as a means of reducing power quickly during a peak load emergency. In the past, such voltage reductions were referred to as "brown-outs" due to the dimming effect voltage reduction may have on incandescent light bulbs. For the most part the term no longer applies as the newer generation of compact fluorescent lamps remains bright as voltage is reduced by up to five percent. Numerous utilities are planning to operate with reduced voltage on a continuous basis (for energy conservation) or during peak load periods (for demand reduction).

To implement CVR effectively with no adverse impact on consumer electrical loads, it is often necessary to implement distribution infrastructure improvements to "flatten" the voltage profile along the feeder. This allows more voltage reduction without violating minimum voltage constraints. Figure 6-2 illustrates the use of switched capacitor banks to "flatten" the voltage profile, followed by voltage reduction. The green line in this Figure 6-2 represents the starting voltage profile at one point in time along the feeder. The red line shows the impact of voltage "flattening". In this cases the effect was achieved by switching on the three switched capacitor banks that are installed on the feeder. The brown line in Figure 6-2, shows the effect of voltage reduction on the "flattened" voltage profile. As seen in Figure 6-2, the voltage level at the end of the feeder that is furthest from the substation changes very little from the starting point. However, the voltage at all other points along the feeder are reduced considerably. This illustrates the benefit of voltage conditioning.

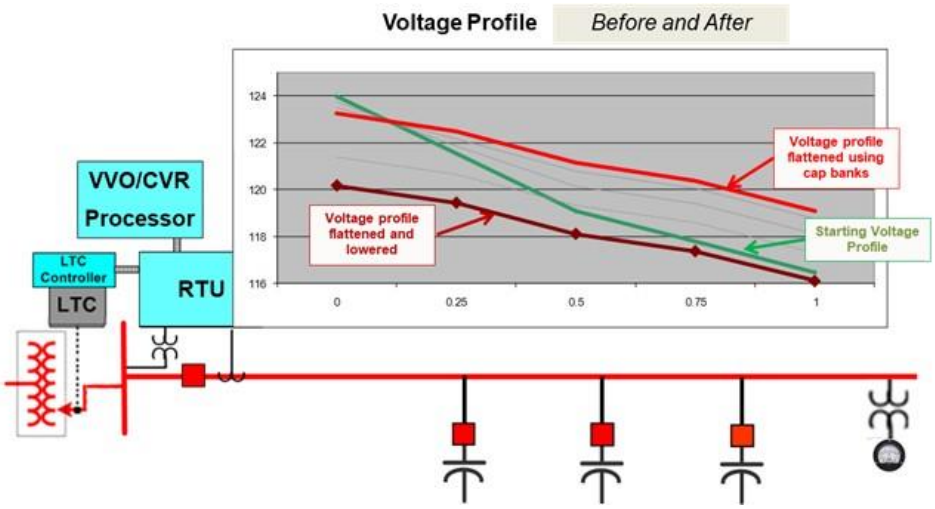


Figure 6-2- "Flattening" And "Lowering" The Voltage Profile

Many electric utilities view VR as a very attractive measure for efficiency improvement, because, in most cases, significant benefits can be achieved for a minimal investment and with no customer sacrifices. Because VR can usually be implemented without making major investments in equipment and infrastructure improvements, benefits can be achieved in the shortest possible time.

The specific benefits that can be achieved vary based on customer type (residential, commercial, industrial, etc.), time of day, day of week and season, climate zone, and other such factors. The amount of benefit is also affected by the degree to which voltage can be reduced. Feeders whose minimum voltage is near the bottom of the acceptable range will provide little or no CVR benefits, while feeders with higher distribution voltage often gain the most from CVR.

CVR benefits will be affected by new "up and coming" appliances that comprise a growing percentage of the load. Many new appliances will be equipped with electronic controls that improve the nominal efficiency of the device. Many of these controls exhibit "constant power" behavior which is not favorable for achieving CVR benefits. With constant power loads, the electricity consumed by the device stays constant as voltage is reduced. However, as the voltage is reduced, current increases which can produce higher electrical (I^2R) losses on the feeder. Due to the critical nature of the application (e.g., system emergency voltage reduction), it is important to be able to predict the outcome of voltage reduction.

A.2 SCADA "RULES-BASED" APPROACH

Consumers Energy uses one of the most common approaches to CVR: the SCADA "rules based" approach. This approach is depicted in Figure 6-3. This approach determines what volt-VAR control actions to take by applying a predetermined set of logical "rules" to a set of real time measurements from the associated substation and feeder. An example rule is: "If the voltage measured at point "X" is less than 120 volts AND the reactive power flow measured at the substation end of the feeder is greater that 900kVAR (lagging), then switch capacitor bank "1" to the ON position". These rules are determined in advance by the distribution engineers and operators using power flow analysis or general knowledge about the historical operation of the feeder.

The SCADA rules-based approach relies on intelligent controllers for interfacing with the switched capacitor banks and voltage regulators. The SCADA rules-based approach uses the Consumers Energy Distribution Supervisory

Control and Data Acquisition (DSCADA) system to interface with the field devices and intelligent controllers. The communication facilities enable the system to base its control actions on overall feeder conditions rather than just on local conditions at the site of the capacitor bank or voltage regulator. The communication facilities also enable Consumers Energy to monitor the operating status of the voltage regulators and switched capacitor banks so that appropriate actions can be taken immediately when a component failure occurs.

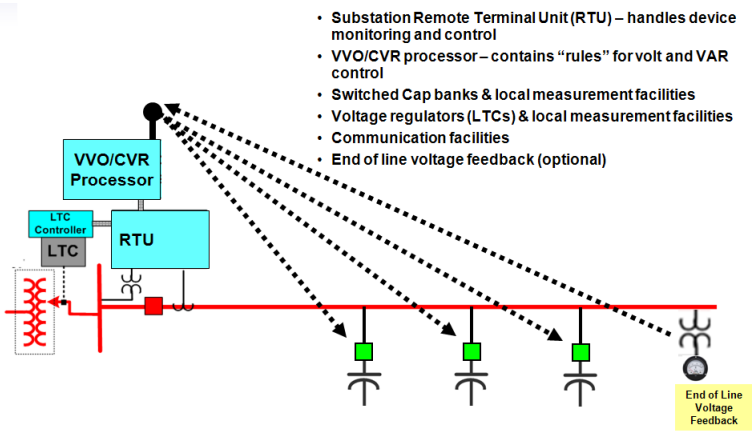


Figure 6-3 SCADA Rules Based Approach

This approach works well for the operating environment that exists on many electric utility distribution feeders today (e.g. minimal DG, infrequent changes in feeder configuration). However, in the future as the penetration of large DG units grows and advanced distribution applications (such as Fault Location Isolation and Service Restoration (FLISR)) become prevalent, the rules-based approach may lack the flexibility to address all future operating possibilities. In such cases, a more sophisticated "model-driven solution" may be needed.

A.3 CVR FACTOR EXPLAINED

CVR factor reduction (also known as load-voltage sensitivity) is an industry standard metric for identifying the effectiveness of voltage on the electric distribution system. CVR factor is given by the following formula:

CVR factor = (% change in kWh energy consumption) / (% change in voltage)

As explained in following sections, the load-voltage sensitivity of a particular electrical device depends on the electrical characteristics of the individual device which can be determined through laboratory testing. The load-voltage sensitivity or CVR factor of an entire customer premise, an entire feeder, an entire substation, or other entity containing more than one appliance, depends on the aggregate load-voltage sensitivities of the individual appliances in the entity.

A.4 LOAD-VOLTAGE SENSITIVITY OF INDIVIDUAL DEVICES

Most electrical appliances consume less electric power when voltage is reduced. The relationship between voltage and electric power for an appliance is given by the "ZIP" model of the appliance, which is a combination of the following components:

- **Constant Impedance Component (Z)** – When voltage (V) applied to a constant impedance device is reduced, the current (I in amperes) drawn by the device decreases by the same amount to keep the impedance ratio (V / I) constant. So, when voltage is reduced, the consumed power (V x I) is lowered by a significant amount. Electric heating elements in water heaters and electric stoves are examples of loads that primarily have constant impedance behavior. Incandescent light bulbs, which are becoming a thing of the past, also exhibit constant impedance behavior. Figure 6-4 below contains a graph showing test results obtained when voltage applied to an incandescent light bulb was varied. The load-voltage sensitivity is the slope of this line, which is approximately 1.6, meaning that if voltage applied to the device is reduced by 1.0%, the power consumed would be 1.6%.

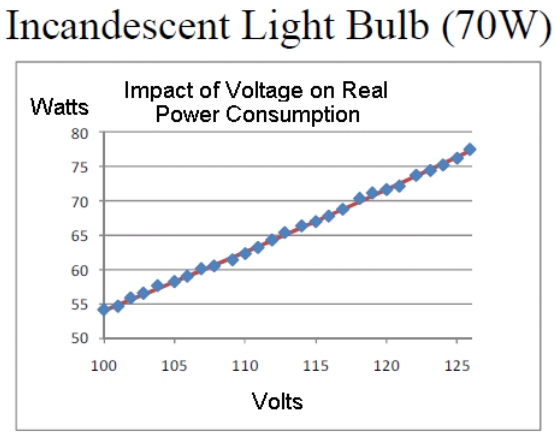


Figure 6-4 Load—Voltage Sensitivity Test Results for Light bulb

- **Constant Current Component (I)** – Constant current loads draw power in proportion to the applied voltage. That is, P= I x V, where current I is held constant. So, the power drawn by constant current loads will be lowered when voltage is reduced, but not as much as constant impedance devices. There are relatively few constant current devices that exhibit constant current behavior. Examples include welding units, smelting equipment, and electroplating processes. However, some electric vehicle chargers may exhibit constant current behavior. Normally, and EV charger exhibits a constant power behavior in which current increased as voltage is reduced to maintain a fixed power draw by the charger. However, when current reaches a maximum amount when current reaches a maximum allowable amount, the current drawn remains fixed and is clamped at the maximum as further voltage reduction occurs.

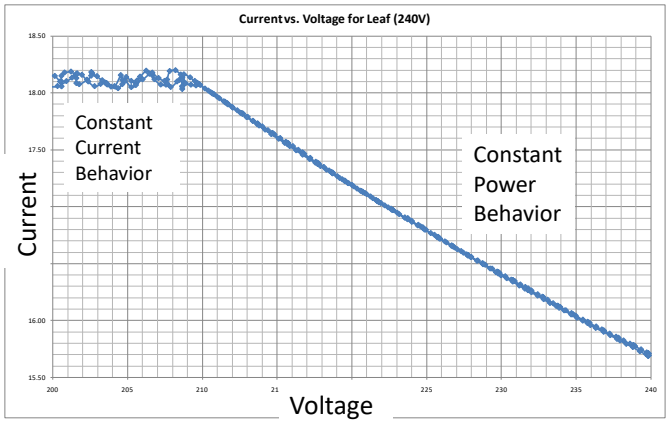


Figure 6-5 Load-Voltage Characteristic of EV Charger

- **Constant Power Component (P)** – Constant power loads draw the same amount of power regardless of the applied voltage. So, the CVR factor for constant power loads is zero. Computer power supplies are constant power devices as are many modern devices that used switched power supplies. Electric motors are often considered to be constant power devices. However, tests have shown that for small voltage reductions (a few percent), motors exhibit constant impedance behavior. Load-Voltage sensitivity for a computer power supply is shown in Figure 6-6 below.

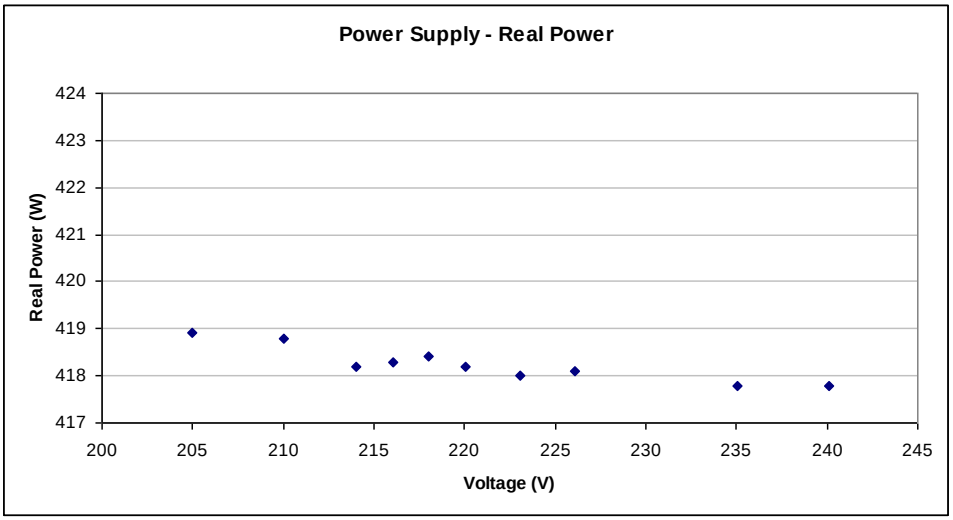


Figure 6-6 Constant Power Behavior of Computer power Supply

Commonly used electrical appliances usually exhibit individual CVR factors that are a combination of the ZIP component characteristics. Figure 6-7 below shows CVR factors for various types of electrical appliances.

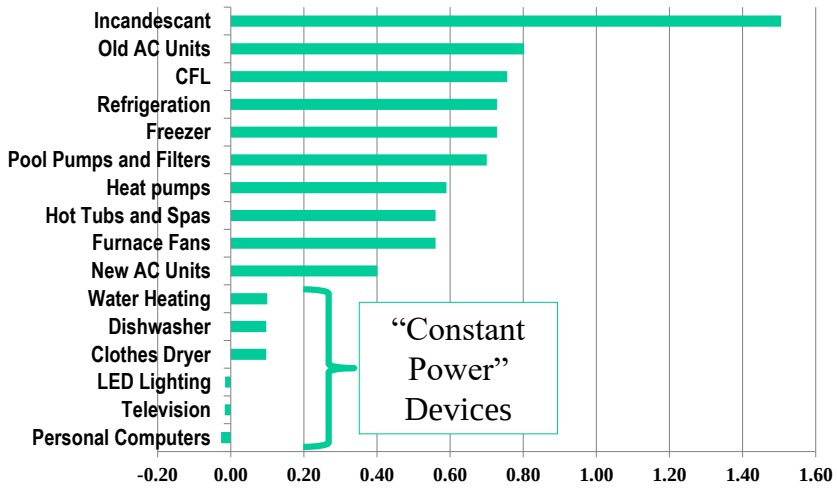


Figure 6-7 CVR Factors for Common AC Appliances

A.5 LOAD-VOLTAGE SENSITIVITY AT THE PREMISE AND FEEDER LEVEL

The power supplied to a single residential or commercial entity is the sum of the power consumed by all the individual electrical appliances within the entity. The Load-Voltage sensitivity or CVR factor for the single entity is the sum of the CVR factors for the individual types of appliances weighted by the percentage of load consumed by each appliance. Figure 6-8 and Figure 6-9 below show how the aggregate load-voltage sensitivity differs for a typical single-family residence and a commercial office building. For these examples, power consumed by each type of appliance has been obtained from RECS and CBECS data published by the US Department of Energy (DOE) for premises located in the "mixed-humid" climate zone. The energy consumed by individual appliances, and the premise CVR factor, would be different in other climate zones.

Year	State	Climate	Customer Class			
2021	New York	MIXED-HUMID	Single-Family			
SAMPLE SIZE:	60					
	Average kWh					
Enduse	Summer	Winter	Shoulder	Total kWh	LTV Factor	KWh x LTV
Clothes Dryer	91	137	160	388	0.8	310.48
Cooking	109	88	145	342	0.3	102.47
Cooling	1,305	0	278	1,583	0.5	791.38
Dishwasher	27	41	48	117	0.5	58.304
Freezer	86	69	115	270	0.3	80.977
Furnace Fans	108	40	54	202	1.23	248.02
Heating	0	131	45	176	0.1	17.552
Lighting (Incand)	100	131	158	389	1.536	597.21
Lighting (CFL)	62	81	98	242	0.748	181.08
Lighting (LED)	26	35	42	103	0.976	100.24
Other	1,428	1,144	1,901	4,473	1	4473
Hot Tubs and Spas	15	13	20	48	1	47.663
Pool Pumps and Filters	143	115	191	449	1.23	552.43
Personal Computers	136	179	215	530	0.1	53.04
Refrigeration	449	360	598	1,407	0.3	422.23
Television	437	352	582	1,371	0.1	137.11
Water Heating	0	0	0	0	0.1	0
	4,524	**2,914**	**4,650**	**12,088**	**Aggregate LTV**	**0.6761**

Figure 6-8 CVR Factor for a typical Single Family Residence

Year	State	Climate	Customer Class			
2021	New York	MIXED-HUMID	Office			
SAMPLE SIZE:	82					
	Average kWh (Total End Use Energy / Total Number of Premises)					
Enduse	Summer	Winter	Shoulder	Total kWh	LTV Factor	KWh x LTV
Computer Use	29,402	38,671	48,579	116,653	0.1	11665.3
Cooking	119	157	197	472	0.3	141.7
Cooling	41,113	0	10,261	51,375	0.5	25687.3
Heating	50	12,627	4,941	17,618	0.2	3523.7
Lighting	62,108	81,685	102,613	246,407	0.748	184312.3
Miscellaneous Use	24,692	32,476	40,796	97,964	1	97964.0
Office Equipment	15,026	19,761	24,824	59,611	0.2	11922.1
Refrigeration	4,507	5,928	7,448	17,884	0.4	7153.5
Ventilation	14,992	19,718	24,769	59,479	0.7	41635.6
Water Heating	1,166	1,533	1,927	4,626	0.1	462.6
	193,177	**212,556**	**266,356**	**672,088**	**Aggregate LTV**	**0.57205**

Figure 6-9 CVR Factor for a Typical Office building

Similarly, the CVR factor for an entire feeder or substation is the weighted sum of the CVR factors for the individual customers connected to the feeder or substation. In this case, the weighting factor is the percentage of total feeder power consumed by each entity.

It can be concluded that the load-voltage sensitivity depends only on the types of appliances and equipment served and the portion of energy consumed by each type of appliance. In other words, two entities (premises, feeders,

substations, etc.) that supply the same types of appliances and energy consumption per appliance will have the same CVR factor.

As explained above, aggregate load-voltage sensitivity depends on appliance type and climate zone. If all Consumers Energy substations and feeders are in the same mixed-humid climate zone, then CVR factor varies only by the customer mix (e.g., residential, commercial, industrial) served by the feeder or substation.

A.6 CVR "BENEFITS" FOR DIFFERENT TYPES OF FEEDERS

While the load-voltage sensitivity is nearly the same for a given set of appliances in a given climate zone, the energy conservation benefits (kWh reduction) for a given feeder or substation will depend on the following items:

- The amount of voltage reduction that is possible without violating voltage limits. A larger voltage reduction will result in larger kWh savings. The possible voltage reduction on short, lightly loaded feeders is usually greater than the possible voltage reduction on longer, heavily loaded feeders (which may be voltage-limited). For example, reducing the voltage by 2% on a 1.0 MWh load with a 0.7 CVR factor will reduced the consumed energy by 1.4%; if voltage can only be reduced by 1%, then kWh savings would be half that amount.

- The total energy consumption by the entity. A one percent voltage reduction on a heavily loaded entity will produce a greater kWh reduction than a lightly loaded entity. For example, reducing the voltage by 2% on a 1.0 MWh load with a 0.7 CVR factor will reduced the consumed energy by 1.4% of 1.0 MWh; a 2% voltage reduction on a 2.0 MWh load would save 1.4% of 2.0 MWh (twice the benefit).

2025 Projects

Line		Outage Data			
No.	**Project Name**	**Outages (12- 24mo Pre-Const.)**	**Outages (12-mo Pre-Const.)**	**2025 Construction**	**Outages (Post Construction)**
1	SYSP MASON SOUTH ST. FUSE COORDINATION	1	3	Q1	0
2	RPOUT KENTWOOD_PRINCETON LCP 0639	2	2	Q1	0
3	RPOUT HOMER_INDUSTRIAL LCP 685	0	0	Q1	0
4	RPOUT WEST RIVER_GRAND RIVER LCP-737	1	1	Q1	0
5	SYSP WEST FENTON OVERPASS LCP#560 UG	0	0	Q1	0
6	RPOUT24 Bullock Stewart LCP918	3	3	Q1	1
7	RPOUT MIDDLEVILLE_BUSINESS LCP 0207	0	0	Q1	1
8	RPOUT ASH ROAD_STERLING RD	1	1	Q1	0
9	RPOUT DEAN ROAD-SHANNON LAKE LCP151	2	0	Q1	0
10	RPOUT LEITH STREET_WESTERN ROAD LCP 519	1	1	Q1	0
11	RPOUT Tustin-Leroy LCP 3964	0	1	Q1	1
12	RPOUT TWIN LAKE_TWIN LAKE LCP 494	1	2	Q1	1
13	RPOUT WHITTUM_ROYSTON LCP 279	3	1	Q1	0
14	RPOUT_ENSLEY_BAPTIST LAKE_LCP 754	0	1	Q1	0
15	RPOUT Dewitt-Geneva Lk LCP Sub	0	0	Q1	1
16	RPOUT KRAFT AVENUE ACQUEST LCP 734 UGL	0	0	Q1	0
17	RPOUT BECKER GILES ROAD LCP 220	1	2	Q1	0
18	RPOUT DIMONDALE_DIMONDALE LCP 878	2	3	Q1	0
19	RPOUT Knight_Rosemary LCP 602 ESIC OHL	1	0	Q1	0
20	RPOUT NORGE MACHINE LINCOLN	1	0	Q1	0
21	RPOUT MESICK-SHERMAN LCP 760	0	1	Q1	1
22	RPOUT MIDDLEVILLE LAFAYETTE SUB	0	2	Q1	0
23	RPOUT CEMI12 QUINCY_QUINCY	1	0	Q1	0
24	RPOUT WAYLAND_WAYLAND LCP 0684	1	0	Q1	0
25	RPOUT-PECK-ROAD_WISE-ROAD-LCP-0024	1	1	Q1	0
26	SYSP17 COTTAGE GROVE_PREVO LCP 998	2	2	Q1	0
27	RPOUT18 BEAVERTON/ROSS LCP 325	0	2	Q1	0
28	RPOUT Otisville/Irish Rd LCP 591	1	1	Q1	0
29	SYSP TALLMAN_WACOUSTA LCP 188	1	1	Q2	0
30	RPOUT ROCKFORD_WOVERINE LCP-333	1	0	Q2	0
31	SYSP19 Larkin_N Midland LCP 404	0	0	Q2	0
32	SYSP ALCONA DAM_GLENNIE	4	2	Q2	2
33	RPOUT 40th Ave - Cable Fault	1	0	Q2	0
34	RPOUT PIGEON LAKE_OLIVE LCP 547	1	2	Q2	0
35	RPOUT JUDD ROAD_OTTAWA LCP 284	3	2	Q2	0
36	RPOUT N MUSKEGON STATE PARK LCP 38	1	0	Q2	0
37	RPOUT HARPER ROAD_ARENS LCP 363	1	3	Q2	0
38	SYSP DEWITT_EAST HERBISON LCP 5914	0	1	Q2	0
39	RPOUT24 Rives Eaton Rd, Rives	4	3	Q2	0
40	RPOUT NUNICA_WILSON LCP 531	2	3	Q2	0
41	RPOUT Bluewater-Colony LCP 173-Poles	0	2	Q2	0
42	RPOUT PETTIS ROAD_PETTIS RD LCP 229	3	4	Q2	0
43	RPOUT DEWITT_DEWITT LCP 570	2	1	Q2	0
44	RPOUT LAKE CITY-STITTLVILLE LCP 187	0	0	Q2	0
45	RPOUT Krafft Acquest LCP 711	0	1	Q2	0
46	RPOUT LETTS ROAD_WALKER 880	2	3	Q2	0
47	RPOUT Haskelite_3 Mile LCP 425	0	0	Q2	0
48	RPOUT ST CHARLES/SAGINAW LCP 604	1	2	Q2	0
49	RPOUT KENT CITY_TYRONE LCP 654	4	1	Q2	0
50	SYSP GRAND LEDGE_ACADEMY LCP 742	0	1	Q2	0
51	**Subtotal**	**57**	**62**		**8**

2025 Projects

Line		Outage Data			
No.	**Project Name**	**Outages (12- 24mo Pre-Const.)**	**Outages (12-mo Pre-Const.)**	**2025 Construction**	**Outages (Post Construction)**
1	RPOUT CEDAR SPRINGS_EDGERTON LCP 300	0	1	Q2	0
2	RPOUT EVANSTON_EVANSTON LCP 565	2	3	Q2	0
3	SYSP GRAND LEDGE_WILLOW LCP 205	0	0	Q2	0
4	RPOUT Middleton Newark LCP884	2	3	Q2	0
5	RPOUT HESPERIA_HESPERIA LCP 797	2	3	Q2	0
6	RPOUT_EAST MUSKEGON_SHERIDAN_LCP 768	1	2	Q3	1
7	RPOUT MAPLE GROVE_SUMMIT AVENUE LCP 390	0	0	Q3	0
8	RPOUT PIGEON LAKE_OLIVE LCP 531	2	2	Q3	0
9	SYSP GRAND LEDGE_HARTEL ROAD LCP 674	1	0	Q3	0
10	Failure Overhead Lines - System P	1	2	Q3	0
11	RPOUT STANDALE_CHESTERFIELD LCP 513	5	3	Q3	1
12	RPOUT TEXAS_EAGLE LAKE LCP SUB - UGL	3	1	Q3	0
13	RPOUT TEXAS_EAGLE LAKE LCP SUB - OHL	3	1	Q3	0
14	RPOUT ROTHBURY_NEW ERA LCP 640	2	2	Q3	0
15	RPOUT HYDE PARK_ROSS LCP 209	3	3	Q3	0
16	RPOUT NESTROM_SOUTH SHORE LCP 597	3	3	Q3	0
17	RPOUT HOGAN ROAD_ROLSTON LCP 467	0	0	Q3	0
18	SYSP CHARLOTTE_WATER WORKS LCP 732	0	0	Q3	0
19	RPOUT VIRGINIA PARK_CASTLE LCP CKT	2	0	Q3	0
20	RPOUT APPLE_CHATTERSON ROAD LCP 605	1	3	Q3	0
21	RPOUT NUNICA_LEONARD LCP 505	0	1	Q3	2
22	FAIL24READING-CAMBRIA-7510 READING RD-RE	0	0	Q3	0
23	RPOUT19Lovejoy Braden Steinacker Recl	1	2	Q3	1
24	SYSP19 Midland_Commercial LCP 342	0	0	Q3	1
25	RPOUT25 Teft Rd Lakefield LCP868	3	3	Q3	1
26	RPOUT CURTIS_MAGRUDDER LCP 543	1	2	Q3	0
27	RPOUT NORTH LANSING_LABORATORY LCP 027	4	3	Q3	0
28	RPOUT CLUB_VILLAGE LCP 236	1	1	Q3	0
29	RPOUT KEATING_WOOD STREET LCP 3813	4	6	Q3	0
30	RPOUT SUNFIELD_SUNFIELD LCP 0729	2	1	Q3	0
31	RPOUT NUNICA_WILSON LCP 0663	9	4	Q3	3
32	RPOUT YORKVILLE_BAYVIEW LCP 144 ESIC OHL	3	2	Q3	0
33	RPOUT EAST LAKE_PINE CREEK LCP 226	1	0	Q3	0
34	RPOUT NESTROM_SOUTH SHORE LCP 873	3	3	Q3	0
35	RPOUT Renton - Watkins First Zone	0	0	Q3	0
36	RPOUT EAST GENESEE AVE/BAGLEY LCP 831	1	1	Q3	0
37	RPOUT YORKVILLE_BAYVIEW LCP 144	3	2	Q3	0
38	SYSP ST CHARLES/FERGUS LCP 319 & 310	0	0	Q3	0
39	RPOUT NUNICA_LEONARD LCP 122	2	2	Q3	0
40	RPOUT NUNICA_LEONARD LCP 125	2	0	Q3	0
41	RPOUT ORIOLE_BRYANT ROAD LCP 861	3	3	Q3	0
42	RPOUT SPRING LAKE_SPRING LAKE LCP 281	1	5	Q3	1
43	RPOUT NESTROM_SOUTH SHORE LCP 557	2	2	Q3	0
44	RPOUT DIMONDALE_DIMONDALE LCP 851	2	2	Q3	0
45	RPOUT HOGSBACK_HOLT ROAD LCP SUB	1	1	Q3	0
46	RPOUT NESTROM_SOUTH SHORE LCP 172	3	3	Q3	0
47	RPOUT Hemlock Nelson LCP361	1	1	Q3	0
48	RPOUT HOPKINS MONTEREY LCP 900	0	0	Q3	1
49	RLBY DEAN ROAD_SHANNOON LAKE LCP 648	0	1	Q3	0
50	RPOUT BELDING_COOKS CORNERS LCP 689	1	1	Q3	0
51	**Subtotal**	**87**	**84**		**12**

Line		2025 Projects							
		Outage Data							
No.	Project Name	Outages (12- 24mo Pre-Const.)		Outages (12-mo Pre-Const.)		2025 Construction		Outages (Post Construction)	
1	RPOUT TAMARACK_AMBLE LCP 521	0		1		Q3		1	
2	RPOUT25 ST CHARLES FERGUS LCP 353	1		1		Q3		0	
3	RPOUT HOLTON_MAPLE ISLAND LCP 658	3		2		Q3		2	
4	RPOUT EAST LAKE_PINE CREEK LCP 063	0		1		Q4		0	
5	RPOUT MILL GROVE_ALLEGAN HYDRO LCP855	3		1		Q4		0	
6	RPOUT ALGER_SKIDWAY LCP 171	1		2		Q4		0	
7	RPOUT HOLTON_HOLTON LCP 882	1		3		Q4		0	
8	RPOUT Peck Road Wise Road LCP437	1		2		Q4		0	
9	RPOUT GREENVILLE_WASHINGTON ST	3		2		Q4		0	
10	SYSP OTSEGO FARMER	1		1		Q4		0	
11	RPOUT DEWITT_HOWE ROAD LCP 450B	2		1		Q4		0	
12	RPOUT ALAMO_Owen LCP Sub	4		1		Q4		0	
13	SYSP21 BITTERSWEET RIVER ROAD	0		1		Q4		0	
14	RPOUT LCP 472-40 LAKE LEANN_BUNDY HILL	0		1		Q4		0	
15	RPOUT LCP 472-40 7751 MORELAND	0		1		Q4		0	
16	RPOUT CENTRAL LAKE_ELLSWORTH LCP 0708	2		2		Q4		0	
17	RPOUT ALAMO_PINE GROVE LCP 646	2		2		Q4		0	
18	RPOUT ROSEBUSH STVNSON LK LCP 221 OHL	0		0		Q4		0	
19	RPOUT14 Pennfield/Pennfield 11643 Bellev	0		1		Q4		0	
20	RPOUT24 ROSEBUSH STVNSON LK LCP 221 UGL	2		2		Q4		0	
21	RPOUT14 Pennfield/Pennfield LCP504	0		1		Q4		0	
22	RPOUT BROADMOOR_NORTH LCP 306	0		0		Q4		0	
23	RPOUT MONTROSE_VOLKMER LCP 322	3		1		Q4		0	
24	RPOUT SLOAN_LONGFELLOW LCP 326	5		4		Q4		1	
25	RPOUT ALGER_SKIDWAY LCP 609	4		2		Q4		0	
26	PULLMAN-PULLMAN ELECTRONIC RECLOSERS	1		1		Q4		1	
27	RPOUT SILVER LAKE_SILVER PINES LCP 5016	2		4		Q4		1	
28	RPOUT25 ROSCOMMON SOUTH BRANCH LCP301 RP	1		3		Q4		0	
29	RPOUT ALGER_SKIDWAY LCP 448	2		2		Q4		0	
30	RPOUT MILLGROVE ALGNHYDR LCP 378 PT 2 UG	1		1		Q4		0	
31	RPOUT HASKELITE_ANN ST LCP 148 ATR RELOC	2		0		Q4		0	
32	**Subtotal**		**47**		**47**				**6**
33	**Total**		**191**		**193**				**26**

Bridge Period Projects

Line No.	Project Name	Outage Data 2025 Outages	2024 Outages
1	APPR RPOUT SAUGATUCK_SILVER LAKE LCP 984	3	4
2	FUSE NEWBURG_BANCROFT LCP 300 9	0	1
3	HZRD KOLASSA_MATTESON LCP 706 1-15	1	1
4	RLBY BELLEVUE_ASSYRIA 007 PT. 1_2	1	1
5	RLBY BELLEVUE_ASSYRIA 007 PT. 3	1	1
6	RLBY Brooklyn_Ford Dearmyer Rd Fuse	0	0
7	RLBY CLEAR LAKE_WATERLOO CKT	0	1
8	RLBY CONVIS CONVIS 418	1	1
9	RLBY LEITH/LEITH LCP 572	1	0
10	RLBY NEFF ROAD_LEWIS ROAD LCP sub	1	0
11	RPOUT - EAST GRANT - MUD FLAT - LCP 728	2	2
12	RPOUT S STATE RD 137102	3	2
13	RPOUT ALAMO_FISH HATCHERY LCP 736	4	4
14	RPOUT ALAMO_OWEN LCP 0240	4	0
15	RPOUT ALAMO_OWEN LCP 0364	6	1
16	RPOUT ALAMO_OWEN LCP 239	4	1
17	RPOUT ALAMO_PINE GROVE LCP 491	4	7
18	RPOUT ALGER_SKIDWAY LCP 0062	2	4
19	RPOUT ALGER_SKIDWAY LCP 449	3	3
20	RPOUT ALGER_SKIDWAY LCP 606	3	4
21	RPOUT ALGER_SKIDWAY LCP 663	3	4
22	RPOUT ALGER_SKIDWAY LCP 663 and 163 PTB	3	4
23	RPOUT ALGER_SKIDWAY LCP 819	4	4
24	RPOUT APPLE_CHATTERSON ROAD LCP 613	1	3
25	RPOUT ARTHUR_ARTHUR LCP 304	1	3
26	RPOUT ARTHUR_BERLIN LCP 0967	1	4
27	RPOUT AUGUSTA_HOSPITAL LCP 534	4	1
28	RPOUT BALDWIN_IDLEWILD LCP 0444	3	1
29	RPOUT BALDWIN_IDLEWILD LCP 421	4	1
30	RPOUT BALZER_SANDERS LCP 0254	3	1
31	RPOUT BAYBERRY_PLEASANT HILL LCP SUB	4	0
32	RPOUT BEECH-NUT_HOLAGAN LCP 266	0	4
33	RPOUT BEHNKE_ANGOLA ROAD LCP 440	6	2
34	RPOUT Belding_City LCP 513	2	6
35	RPOUT BELKNAP_TODD FARM LCP 921	4	1
36	RPOUT BELL ROAD/ALBEE LCP 702	3	1
37	RPOUT BENSTON_DURHAM LCP 481	0	2
38	RPOUT BENSTON_DURHAM LCP 481 - OH	0	2
39	RPOUT BENTHEIM_140TH AVENUE LCP 117	2	0
40	RPOUT BIG PRAIRIE/OXBOW LCP 908	3	3
41	RPOUT BILMAR PEIRCE LCP 725	0	0
42	RPOUT BIL-MAR_PIERCE LCP 217	1	0
43	RPOUT BISHOP_RAINBOW LCP 061	0	0
44	RPOUT BLACK RIVER_FILLMORE LCP 146	0	1
45	RPOUT BREEDSVILLE_BREEDSVILLE LCP 341	1	0
46	RPOUT BREEDSVILLE_GRAND JUNCTION LCP 823	2	5
47	RPOUT BROADWAY_BLACK CREEK LCP 666	3	1
48	RPOUT Brooklyn_Ford N Main St Michigan	0	0
49	RPOUT BURR OAK_INDUSTRIAL LCP 521	0	2
50	RPOUT BUSCH ROAD/CURTIS LCP 0134	5	0

Bridge Period Projects

Line No.	Project Name	Outage Data 2025 Outages	2024 Outages
1	RPOUT BUTTERFIELD_M-82 LCP 221	3	3
2	RPOUT BYRON CENTER_BYRON CENTER LCP 0428	4	3
3	RPOUT CALVIN_ROSEMONT LCP 0572	0	2
4	RPOUT CASCO_BLUFF LCP SUB	1	0
5	RPOUT CASCO_HAWKHEAD LCP 466	5	3
6	RPOUT CASCO_HAWKHEAD LCP 511	2	2
7	RPOUT CENTRAL LAKE_ELLSWORTH LCP 742	4	1
8	RPOUT CHAPIN_MARION LCP 933	2	0
9	RPOUT CHESTER_MORRELL LCP 0233	2	4
10	RPOUT CLARE_FARWELL LCP 373	5	0
11	RPOUT CLUB_ADVENTURE LCP 891	3	1
12	RPOUT COCHRAN_SNOW LCP 124	2	4
13	RPOUT Colon_Colon LCP 947	1	3
14	RPOUT COMSTOCK_TUNIER LCP 891	2	3
15	RPOUT COMSTOCK_TUNIER LCP 891 ESIC OHL	2	3
16	RPOUT COOPER_NAGEL LCP 043	3	1
17	RPOUT COURT_KENT LCP 328	1	0
18	RPOUT Cowan Lake_Ramsdell LCP 829	0	0
19	RPOUT CRAHEN_LOMOND LCP 345	2	1
20	RPOUT CRYSTAL_MT HOPE ROAD LCP 438	1	1
21	RPOUT CUTLERVILLE_GAINES LCP 0172	2	0
22	RPOUT CUTLERVILLE_GAINES LCP 0874	2	3
23	RPOUT DEAN ROAD_KELSEY-HAYES LCP 0037	0	2
24	RPOUT DEAN ROAD_PARSHALLVILLE LCP 16 SH1	1	2
25	RPOUT DEAN ROAD_PARSHALLVILLE LCP 16 SH1_2	1	2
26	RPOUT DEER LAKE_BALL AVENUE LCP 096	0	0
27	RPOUT DELTON_DELTON LCP 0126	5	1
28	RPOUT DEWEY SEATING LCP CKT 1 - 4	0	2
29	RPOUT DIMONDALE/M99 LCP581	0	0
30	RPOUT DONTZ ROAD_KOTT ROAD LCP 515	1	1
31	RPOUT DRAKE ROAD_COUNTRY CLUB LCP SUB	3	1
32	RPOUT Durand City Fusing	0	0
33	RPOUT Durand City LCP 551	3	0
34	RPOUT DUTTON_GATEWAY CROSSING LCP 0711	0	0
35	RPOUT ELEVENTH STREET_BASELINE LCP 871	3	1
36	RPOUT ENGLISHVILLE_PINE ISLAND LCP440 UG	2	0
37	RPOUT EVANSTON_EVANSTON LCP 810	4	0
38	RPOUT FILLMORE_NORTH BLENDON LCP 0285	5	0
39	RPOUT FILLMORE_NORTH BLENDON LCP 0396	3	1
40	RPOUT FISH LAKE_SEVEN LAKES LCP 0136	0	1
41	RPOUT FLUSHING_MARY STREET LCP 502	2	1
42	RPOUT FOREMAN_VERGENNES LCP 0741	4	0
43	RPOUT FRANKFORT_CRYSTALLIA LCP 5032	4	1
44	RPOUT FROST_LEOTA LCP 474	3	3
45	RPOUT FRUITPORT_JUDSON ROAD LCP 0642	2	5
46	RPOUT FRUITPORT_JUDSON ROAD LCP 0763	4	2
47	RPOUT FRUITPORT_JUDSON ROAD LCP 437	4	1
48	RPOUT Ft Custer - Hill Brady LCP 254	1	0
49	RPOUT GLEN LAKE_ARBOR LCP 8312	1	1
50	RPOUT GODFREY_FLAT RIVER LCP 0535	4	1

Bridge Period Projects

Line No.	Project Name	Outage Data 2025 Outages	2024 Outages
101	RPOUT GRAND VALLEY/TALLMADGE LCP 149	3	1
102	RPOUT GRANT_MASON DRIVE LCP 238	5	2
103	RPOUT GRASS LAKE_GRASS LAKE LCP 624	2	1
104	RPOUT GREENWOOD_INDIAN LAKE LCP 329	2	2
105	RPOUT GULL LAKE_TURNER LCP 330	4	0
106	RPOUT HAGADORN-WATER SUB	1	3
107	RPOUT HANOVER_HORTON	1	0
108	RPOUT HANOVER_HORTON LCP 507	4	3
109	RPOUT HASKELITE_FISHER BODY LCP 870	1	3
110	RPOUT HESPERIA_RURAL LCP 035	1	0
111	RPOUT HESPERIA_RURAL LCP 481	1	8
112	RPOUT HESPERIA_RURAL LCP 481 - OHL	1	8
113	RPOUT HILL ROAD_REGENCY LCP 113	2	0
114	RPOUT HOGSBACK_CEDAR LCP 733	0	0
115	RPOUT Honor_Platte LCP 0107	3	1
116	RPOUT HONOR_PLATTE LCP 098	0	0
117	RPOUT HONOR_PLATTE LCP 144 - OHL	8	1
118	RPOUT HOPKINS_HOPKINS LCP 0317	4	3
119	RPOUT Hubbardston_Stoney Creek LCP 460	2	4
120	RPOUT HULL ST_CRANBERRY LCP-411 UG CABLE	1	1
121	RPOUT HULL STREET_LIME LAKE LCP 259	2	1
122	RPOUT HULL STREET_LIME LAKE LCP 807	1	2
123	RPOUT INDIAN RIVER_TOPINABEE LCP 0617	3	3
124	RPOUT INDIAN RIVER_TOPINABEE LCP 659	7	2
125	RPOUT INDIAN RIVER_TOPINABEE LCP SUB	3	1
126	RPOUT IVANREST_IVANREST LCP 0611	2	0
127	RPOUT JOHNSON_CEDAR LCP 0566	1	4
128	RPOUT JOHNSON_CEDAR LCP 573	1	4
129	RPOUT JOHNSON_LINCOLN LCP 0224-OHL	1	3
130	RPOUT JUDD ROAD_CARMANWOOD LCP 545	0	0
131	RPOUT KENDALL_WESTWOOD LCP 021	3	3
132	RPOUT KILGORE_TIMBERLANE LCP 907	0	0
133	RPOUT KRAFT AVENUE_FOOTHILLS LCP 910	3	2
134	RPOUT LEVELY_STURGEON LCP 011	5	3
135	RPOUT LOGISTIC FELCH LCP 837	4	2
136	RPOUT MAPLE CITY_CEDAR LCP 728	3	4
137	RPOUT MARKER LAKE_JACKSON ROAD LCP 364	4	1
138	RPOUT MARNE_WRIGHT LCP 047	3	1
139	RPOUT MARTIN_SHELBYVILLE LCP 0232	4	2
140	RPOUT MCCRACKEN_LEON LCP 172	3	3
141	RPOUT MCNALLY_LEXALITE LCP 099	2	2
142	RPOUT MILL GROVE_DUMONT LCP 667	2	2
143	RPOUT MILLGROVE ALGNHYDR LCP 378 PT 2	0	0
144	RPOUT MONTEREY_KNELLER POLES	0	0
145	RPOUT MONTROSE_VOLKMER LCP 322 PT 2 RAIL	0	0
146	RPOUT MULLINS_ROYAL VISTA LCP 446	0	0
147	RPOUT MURNER_ASPEN LCP 0915	11	2
148	RPOUT MURNER_ASPEN LCP SUB	5	0
149	RPOUT MURNER_VAN TYLE CALKINS ESIC UGL	7	0
150	RPOUT NEELEY_HOOPER LCP 961 ESIC OHL	2	5

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Line No.	Project Name	Outage Data 2025 Outages	2024 Outages
1	RPOUT NEFF ROAD_DODGE ROAD LCP 325	4	1
2	RPOUT NESTROM_SCENIC DRIVE LCP 191	1	1
3	RPOUT NESTROM_SOUTH SHORE LCP 629	1	3
4	RPOUT NEW LOTHROP_BYRON ROAD LCP 273	1	1
5	RPOUT NEW LOTHROP_BYRON ROAD LCP 274	1	1
6	RPOUT NEW RICHMOND_NEW RICHMOND LCP 848	1	5
7	RPOUT NORTH KENT_MALL LCP 165 UG CABLE	3	2
8	RPOUT NORTH LANSING_LABORATORY LCP 027	3	2
9	RPOUT NORTON_HILE ROAD LCP 444	2	2
10	RPOUT NORTON_HILE ROAD SUB EXIT	2	0
11	RPOUT NORTON_PONTALUNA ROAD LCP 335	2	5
12	RPOUT NORTON_PONTALUNA ROAD LCP 359	4	1
13	RPOUT NUNICA_WILSON LCP 508	2	4
14	RPOUT NUNICA_WILSON LCP 568	9	3
15	RPOUT OBERLIN_BENMARK LCP 639	1	4
16	RPOUT ORIOLE_HAMLIN LCP 5061	3	1
17	RPOUT PAVILION_MERIDETH LCP SUB	2	1
18	RPOUT PEACOCK_STOLL ROAD LCP 492	0	1
19	RPOUT PECK ROAD_WISE ROAD LCP 484	2	4
20	RPOUT PELLSTON_BURT LAKE LCP 175	4	2
21	RPOUT PICKEREL_INDIAN LAKE LCP 803	1	6
22	RPOUT PIGEON LAKE_PIGEON LCP 210	2	1
23	RPOUT PIGEON LAKE_PIGEON LCP 267	2	1
24	RPOUT PIGEON LAKE_PIGEON LCP 454 PART 1_2	2	3
25	RPOUT PIGEON LAKE_PIGEON LCP 802	1	1
26	RPOUT PIGEON LAKE_PIGEON LCP 803	3	2
27	RPOUT PIGEON LAKE_PIGEON LCP 871	6	1
28	RPOUT PLAINFIELD_BELMONT ASC RECONDUCTOR	1	1
29	RPOUT PORTSMOUTH/BLUMFIELD LCP 575	1	0
30	RPOUT PORTSMOUTH/INDIANTOWN LCP 054	4	0
31	RPOUT PRESCOTT_LOGAN LCP 527	2	6
32	RPOUT PRICE ROAD_MERIDIAN LCP 0513	1	4
33	RPOUT RANGER LAKE/LUPTON LCP 0071	4	2
34	RPOUT RAVENNA_MOORLAND LCP 177	6	2
35	RPOUT RED ARROW/OGEMA TLMS	0	0
36	RPOUT RIVERTOWN_56TH LCP 941	0	1
37	RPOUT SARANAC_CENTERLINE LCP 509	2	5
38	RPOUT SARANAC_KEENE LCP 669	3	1
39	RPOUT SAUGATUCK_SILVER LAKE LCP SUB	1	0
40	RPOUT SAUGATUCK-DOUGLAS CEMI	2	2
41	RPOUT SAVIDGE_BOOM ROAD LCP 729	3	1
42	RPOUT SPRING DRIVE_BISHOP LAKE CKT	2	3
43	RPOUT STANDALE_CHESTERFIELD LCP 312	1	5
44	RPOUT STANDALE_PARKSIDE LCP 156	0	0
45	RPOUT STANDALE_STANDALE LCP 356	0	0
46	RPOUT STONEGATE_BREVIS LCP 541	1	4
47	RPOUT SWAN CREEK_COPPER LCP 136 and 123	1	1
48	RPOUT SWAN CREEK_COPPER LCP 810	2	3
49	RPOUT SWAN CREEK_MINING LCP 070	2	1
50	RPOUT SWAN CREEK_MINING LCP 105	0	0

Bridge Period Projects

Line No.	Project Name	Outage Data 2025 Outages	2024 Outages
1	RPOUT SWAN CREEK_MINING LCP 141	3	4
2	RPOUT SWAN CREEK_MINING LCP 180	3	6
3	RPOUT SYLVAN CITY LCP 797	1	6
4	RPOUT TALLMAN_WACOUSTA LCP 631	4	0
5	RPOUT Teft Rd Graham LCP349	1	0
6	RPOUT Teft Rd Lakefield LCP331	2	5
7	RPOUT TEXAS_EAGLE LAKE LCP 760	1	2
8	RPOUT THORNTON_WEST RIVER RD LCP 352	1	1
9	RPOUT TRUFANT_MASTON LAKE LCP 206	4	6
10	RPOUT TUSTIN_LUTHER LCP 553	0	1
11	RPOUT TUSTIN_LUTHER LCP 568	3	2
12	RPOUT TUSTIN_LUTHER LCP 807	4	0
13	RPOUT TWIN LAKE_TWIN LAKE LCP 777	5	3
14	RPOUT VAN BUREN_VAN BUREN LCP 0889	3	1
15	RPOUT VANDERBILT_WOLVERINE LCP 346	5	2
16	RPOUT VANDERBILT_WOLVERINE LCP 471	2	2
17	RPOUT WAGER_MARENGO LCP SUB	2	0
18	RPOUT WAGER_PARKLAND LCP 711 ESIC OHL	1	2
19	RPOUT WEALTHY STREET_WATSON LCP 221	0	0
20	RPOUT WESTERN AVENUE_BARCLAY LCP 376	2	4
21	RPOUT WHITEHALL_HANSON LCP 758	2	0
22	RPOUT WHITTEMORE_M-65 LCP 417	1	3
23	RPOUT WHITTEMORE_M-65 LCP 465	0	0
24	RPOUT WHITTEMORE_M-65 LCP 919	2	1
25	RPOUT WHITTUM_PETRIEVILLE ATR LOOP	1	1
26	RPOUT WILLIAMS_CRESENT	0	0
27	RPOUT WILLIAMS_ELY LCP 375	0	6
28	RPOUT WIRTZ ROAD_BOWMANVILLE	0	0
29	RPOUT WIRTZ ROAD_BOWMANVILLE LCP 461	0	3
30	RPOUT YORKVILLE_BAYVIEW LCP 144	3	4
31	RPOUT-MURNER_VAN TYLE LCP 930	3	4
32	SYSP BILLWOOD_BILLWOOD LCP SUB	0	1
33	SYSP SWARTZ CREEK_MAPLE ROAD LCP 216	0	1
34	SYSP WAMPLERS/FRANKLIN	0	5
35	SYSP WAMPLERS_STAGECOACH	1	1

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Line No.	Project Name	Outage Data 2025 Outages	2024 Outages
1	RPOUT ABBE-ABBE LCP 144	8	3
2	RPOUT ABBE-HWY 33 LCP 341	7	0
3	RPOUT ABERDEEN-HOLLYWOOD LCP 755	2	5
4	RPOUT AGNEW-WEYBURN LCP 309	5	2
5	RPOUT ALAMO-FISH HATCHERY LCP 736	4	4
6	RPOUT ALAMO-OWEN LCP 222	5	5
7	RPOUT ALAMO-OWEN LCP 364	6	1
8	RPOUT ALGER-SKIDWAY LCP CKT	5	7
9	RPOUT APPLETON-WALDRON WAY LCP 444	6	3
10	RPOUT ARCADIA-STARKE LCP 553	6	6
11	RPOUT ARCADIA-STARKE LCP 577	8	0
12	RPOUT AUGUSTA-AUGUSTA LCP 684	5	2
13	RPOUT BABCOCK-FRANCISCO LCP 117	7	0
14	RPOUT BAGLEY-OTSEGO LAKE LCP 196	7	0
15	RPOUT BAGLEY-OTSEGO LAKE LCP CKT	6	3
16	RPOUT BARRYTON-BARRYTON LCP 255	6	2
17	RPOUT BARRYTON-CHIPPEWA LAKE LCP 496	3	4
18	RPOUT BEHNKE-ANGOLA ROAD LCP 440	6	2
19	RPOUT BEHNKE-ANGOLA ROAD LCP 755	2	6
20	RPOUT BELDING-COOKS CORNERS LCP 83	6	3
21	RPOUT BENSTON-DURHAM LCP 730	3	4
22	RPOUT BIG PRAIRIE-BIG BEND LCP 532	7	5
23	RPOUT BIG PRAIRIE-OXBOW LCP 878	2	5
24	RPOUT BITTERSWEET-RIVER ROAD LCP 753	3	5
25	RPOUT BREEDSVILLE-GRAND JUNCTION LCP 823	2	5
26	RPOUT BYRON CENTER-BYRON CENTER LCP 428	4	3
27	RPOUT CAMELOT LAKE-LOOMIS LCP 132	2	7
28	RPOUT CANNONSBURG-WEST CANNON LCP 379	3	4
29	RPOUT CASCADE-THORNCREST LCP 481	4	5
30	RPOUT CASCO-HAWKHEAD LCP 466	5	3
31	RPOUT CASINO-LEATON LCP 276	5	3
32	RPOUT CEDAR SPRINGS-NELSON LCP 333	6	0
33	RPOUT CENTREVILLE-LAKE TEMPLENE LCP 841	5	3
34	RPOUT CLARE-FARWELL LCP 368	5	2
35	RPOUT COLON-COLON LCP 816	8	2
36	RPOUT CONCORD-KING ROAD LCP 36	1	6
37	RPOUT CONKLIN PARK-CROTON LCP 946	6	1
38	RPOUT CONKLIN PARK-HOLLY LCP 922	7	1
39	RPOUT CONVIS-CONVIS LCP 311	2	6
40	RPOUT CONVIS-WALNUT POINT LCP 9	6	3
41	RPOUT DELTON-CLOVERDALE LCP 964	6	2
42	RPOUT DELTON-DELTON LCP 122	5	2
43	RPOUT DENNISON-SOUTH POLKTON LCP 433	6	2
44	RPOUT DUPONT-OLD CHANNEL LCP 644	3	4
45	RPOUT ELEVENTH STREET-BASELINE LCP 405	3	5
46	RPOUT FENNVILLE-PEACH BELT LCP 191	4	3
47	RPOUT FIFTEEN MILE ROAD-A DRIVE LCP CKT	2	5
48	RPOUT FILLMORE-NORTH BLENDON LCP 554	2	5
49	RPOUT FINE LAKE-BRISTOL LCP 417	2	4
50	RPOUT FOREMAN-VERGENNES LCP 533	5	3

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Line No.	Project Name	Outage Data 2025 Outages	2024 Outages
1	RPOUT FOREST GROVE-OTTOGAN LCP 514	2	6
2	RPOUT FOX FARM-GRANT LCP 599	4	2
3	RPOUT FRANKFORT-CRYSTALLIA LCP 360	6	4
4	RPOUT FROST-LONG LAKE LCP 267	2	6
5	RPOUT FRUITPORT-JUDSON ROAD LCP 642	2	5
6	RPOUT GALESBURG-CHARLESTON LCP 464	6	1
7	RPOUT GALESBURG-GALESBURG LCP 295	3	3
8	RPOUT GENESEEVILLE-PINEWOOD LCP CKT	6	1
9	RPOUT GERRISH-LEGION LCP 476	7	2
10	RPOUT GILSON-WYMAN LCP 460	5	1
11	RPOUT GLEN LAKE-BURDICKVILLE LCP 960	8	1
12	RPOUT GRASS LAKE-GRASS LAKE LCP 8	0	10
13	RPOUT GRAYLING-RIVER LCP CKT	6	1
14	RPOUT HANOVER-HORTON LCP 404	5	3
15	RPOUT HANOVER-HORTON LCP 507	4	3
16	RPOUT HARRIETTA-BOON LCP 717	2	5
17	RPOUT HARRIETTA-BOON LCP 744	5	2
18	RPOUT HARRISON-HARRISON LCP 5926	2	6
19	RPOUT HARRISON-LILLEY LAKE LCP 334	6	1
20	RPOUT HARVARD LAKE-COURTLAND LCP 603	3	4
21	RPOUT HESPERIA-RURAL LCP 938	0	8
22	RPOUT HOMESTEAD-BEULAH LCP 186	5	3
23	RPOUT HOMESTEAD-BEULAH LCP 207	5	2
24	RPOUT HONOR-PLATTE LCP 144	8	1
25	RPOUT HUBBARD LAKE-HUBBARD LAKE LCP CKT	3	7
26	RPOUT HUDSON-WATERWORKS LCP 880	5	1
27	RPOUT HULL STREET-CRANBERRY LCP 329	4	9
28	RPOUT HULL STREET-CRANBERRY LCP 86	2	6
29	RPOUT INDIAN RIVER-TOPINABEE LCP 603	5	3
30	RPOUT INDIAN RIVER-TOPINABEE LCP 659	7	2
31	RPOUT JEFFS ROAD-ADLER ROAD LCP 159	6	1
32	RPOUT JOPPA-BECKLEY LCP 868	4	3
33	RPOUT JUDD ROAD-AINSWORTH LCP 689	0	7
34	RPOUT KEATING-WOOD STREET LCP 3813	6	4
35	RPOUT KENT CITY-TYRONE LCP 529	4	3
36	RPOUT KINDERHOOK-LAKE DRIVE LCP 756	3	4
37	RPOUT LAMOREAUX-LAMOREAUX LCP 495	0	8
38	RPOUT LAWRENCE-CHRISTIE LAKE LCP 675	2	8
39	RPOUT LEELANAU-BELANGER CREEK LCP 7013	4	3
40	RPOUT LEELANAU-OMENA BAY LCP 679	2	6
41	RPOUT LEFFINGWELL-MICHIGAN OAKS LCP 12	2	6
42	RPOUT LELAND-LELAND LCP 240	6	3
43	RPOUT LELAND-LELAND LCP 399	8	0
44	RPOUT LELAND-LELAND LCP 6715	5	3
45	RPOUT LELAND-LELAND LCP CKT	4	3
46	RPOUT LETTS ROAD-MONROE ROAD LCP 212	1	7
47	RPOUT LEVELY-STURGEON LCP 11	5	3
48	RPOUT LYONS-COLLINS-RURAL LCP 172	2	4
49	RPOUT MACKINAW CITY-POND STREET LCP 504	6	2
50	RPOUT MAINES ROAD-WELLMAN ROAD LCP 113	4	4

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Line No.	Project Name	Outage Data 2025 Outages	2024 Outages
1	RPOUT MAPLE CITY-CEDAR LCP 724	6	1
2	RPOUT MAPLE CITY-CEDAR LCP 728	3	4
3	RPOUT MAPLE CITY-SUGAR LOAF LCP 109	2	6
4	RPOUT MARKEY-CARRICK LCP 456	8	2
5	RPOUT MCBAIN-VOGEL CENTER LCP 200	5	2
6	RPOUT MCMILLAN-BEATTIE LCP 275	5	3
7	RPOUT MESICK-SHERMAN LCP 237	5	2
8	RPOUT MILTON-MILLPOND LCP 809	4	3
9	RPOUT MONTROSE-VOLKMER LCP 995	5	4
10	RPOUT MORGAN-ORCHARD LCP 24	1	7
11	RPOUT MORGAN-ST MARYS LCP 176	4	6
12	RPOUT MORGAN-ST MARYS LCP 248	3	4
13	RPOUT MORGAN-ST MARYS LCP 317	7	5
14	RPOUT MORGAN-ST MARYS LCP 386	5	4
15	RPOUT MURNER-VAN TYLE LCP CKT	7	0
16	RPOUT NESTROM-SCENIC DRIVE LCP 244	4	3
17	RPOUT NESTROM-SOUTH SHORE LCP 294	5	5
18	RPOUT NESTROM-SOUTH SHORE LCP 560	2	6
19	RPOUT NEWBURG-BANCROFT LCP 273	6	1
20	RPOUT NINETEEN MILE RD-CEMENT LCP 529	6	3
21	RPOUT NORTON-PONTALUNA ROAD LCP 335	2	5
22	RPOUT NUNICA-WILSON LCP 410	0	7
23	RPOUT NUNICA-WILSON LCP 568	9	3
24	RPOUT NUNICA-WILSON LCP 663	3	7
25	RPOUT OBERLIN-BENMARK LCP 967	3	5
26	RPOUT OHMAN ROAD-HERSEY LCP 403	1	6
27	RPOUT OHMAN ROAD-HERSEY LCP 623	6	1
28	RPOUT OHMAN ROAD-SEARS LCP 858	5	2
29	RPOUT OLIVET-COLLEGE LCP 158	4	5
30	RPOUT ONSTED-ONSTED LCP 389	2	5
31	RPOUT ORLEANS-ORLEANS LCP 67	1	9
32	RPOUT OSCODA-BUTLER HEIGHTS LCP 313	5	2
33	RPOUT PALO-PALO LCP 198	6	1
34	RPOUT PALO-PALO LCP 573	3	4
35	RPOUT PARMA-BALDWIN LCP 15	3	4
36	RPOUT PEACOCK-STOLL ROAD LCP 420	3	7
37	RPOUT PEACOCK-STOLL ROAD LCP 462	3	5
38	RPOUT PETTIS ROAD-HONEY CREEK LCP 988	5	4
39	RPOUT PICKEREL-INDIAN LAKE LCP 803	1	6
40	RPOUT PIERSON-PIERSON LCP 284	4	3
41	RPOUT PIGEON LAKE-PIGEON LCP 871	6	1
42	RPOUT PITTSFORD-CHURCH ROAD LCP 525	2	4
43	RPOUT PORTAGE-CARPENTERS CORNERS LCP 133	3	5
44	RPOUT PRESCOTT-MAPLE RIDGE LCP 256	2	6
45	RPOUT PRICE ROAD-MERIDIAN LCP 530	5	1
46	RPOUT RANGER LAKE-LUPTON LCP 71	4	2
47	RPOUT RAVENNA-MOORLAND LCP 177	6	2
48	RPOUT READING-CAMBRIA LCP 750	4	6
49	RPOUT ROBERTS STREET-DETTMAN LCP 828	3	4
50	RPOUT RODNEY-HORSE HEAD LAKE LCP 337	4	3

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1	RPOUT RODNEY-HORSE HEAD LAKE LCP 352	18	1
2	RPOUT SANDERSON-COUNTY FARM LCP 414	1	6
3	RPOUT SARANAC-CENTERLINE LCP 509	2	5
4	RPOUT SARANAC-RIVERSIDE LCP 732	4	3
5	RPOUT SAUGATUCK-SILVER LAKE LCP 984	3	4
6	RPOUT SCIPIO-POPE ROAD LCP 691	4	4
7	RPOUT SHERIDAN-FENWICK LCP 826	2	8
8	RPOUT SHERIDAN-SIDNEY LCP 3	1	6
9	RPOUT SILVER LAKE-SILVER PINES LCP 5016	6	2
10	RPOUT SKYLARK-RIVERBEND LCP 300	0	7
11	RPOUT SMITH CREEK-WRIGHT LCP 5039	5	4
12	RPOUT SPRING LAKE-SPRING LAKE LCP 281	2	4
13	RPOUT SPRINGPORT-DEVEREAUX LCP 426	1	6
14	RPOUT STANTON-DICKERSON LAKE LCP 6	10	10
15	RPOUT STOCKBRIDGE-STOCKBRIDGE LCP 576	5	1
16	RPOUT THORNTON-WEST RIVER RD LCP 691	7	2
17	RPOUT TREMAINE-JORDAN LAKE LCP 563	4	5
18	RPOUT TRUFANT-MASTON LAKE LCP 206	4	6
19	RPOUT TUSTIN-LUTHER LCP 832	6	3
20	RPOUT VANDERBILT-CORWITH LCP 248	4	4
21	RPOUT VIRGINIA PARK-CASTLE LCP 901	4	6
22	RPOUT WALLOON-WATERWORKS LCP 500	3	4
23	RPOUT WARNER-MILO LCP 107	7	0
24	RPOUT WILLIAMS-ELY LCP 366	5	7
25	RPOUT WILLIS ROAD-LIST ROAD LCP 210	0	3
26	RPOUT WOODWARD-PLEASANT LAKE LCP 984	9	0

Consumers Energy

LVD Planning
CONCEPT APPROVAL

Notification Concept Number: 1072892823

Project Title: Ferrand Estates
Work HQ: GRA
Date: 1/30/2025
Proposed Year of System Changes: 2026

Problem Description:

Ferrand Estates is a large, dense mobile home park in Grand Rapids serving approximately 429 customers. The underground electric system was installed decades ago and was not designed for the way the park has evolved over time. Homes and permanent structures have since been placed over portions of the underground system, leaving critical equipment and connections buried, difficult to access, and hard to repair safely.

Since 2021, the area has experienced 51 total outage events, including 41 unplanned outages. Unplanned outages in this location have an average restoration time (CAIDI) of approximately 269 minutes (4.5 hours), significantly driven by the difficulty in locating and repairing faults. While nearly half of unplanned events originate on secondary or service facilities, crews are often required to de-energize entire transformer areas to safely troubleshoot buried connections. As a result, the vast majority of unplanned Customer Minutes Interrupted (CMI) accrue at the transformer or primary level, impacting large groups of customers during restoration.

Operations reports being on site approximately once per month to address primary, secondary, or service-related issues in this park. Outages are frequently hard to locate, often occurring under newer trailer locations, with limited access and challenging MISS DIG constraints. The system also contains legacy Y-spliced secondary connections that are failure-prone and live-front transformer installations, which increase safety risk and further restrict restoration flexibility.

Portions of the vintage primary have already been replaced under fail-order conditions, restoring service in the moment but not correcting the underlying system design. Without comprehensive intervention, remaining vintage primary and buried secondary connections are expected to continue failing, resulting in long restoration times, repeated emergency work, and significant customer impact. Absent this investment, continued fail-order repairs are expected to restore service in the near term but will not improve restoration speed, access, or outage scope.

Alternative Solutions:

1. Remove the 9 existing 100 kVA live-front transformers and install 14 dead-front 100 kVA transformers as shown in the scope map. Install new 1/0 aluminum underground primary to connect the transformers. Replace all secondary in the area with 350 aluminum conductor, designed to current new-business voltage drop and flicker standards. Install secondary cabinets for every four services where feasible to improve system flexibility and maintainability. Replace one section of secondary prior to implementation under Notification 1072824896.

Install a new primary tie connecting the southeast corner of the loop to the neighboring loop to improve sectionalization during outages.
Estimated customer minutes saved =

Estimated Design Hours = 5036

Estimated Loaded Cost = $2,053,901

Miles = 6

2. Replace the 9 existing 100 kVA live-front transformers in the area with dead-front 100 kVA transformers as shown in the scope map. Replace all underground primary in the area with 1/0 aluminum conductor. Replace all secondary in the area with 350 aluminum conductor. Install secondary cabinets for every four services where feasible to improve system flexibility and maintainability. Replace one section of secondary prior to implementation under Notification 1072824896.
Estimated customer minutes saved =

Estimated Design Hours = 4602

Estimated Loaded Cost = $1,630,905

Miles = 6

3. Replace the 9 existing 100 kVA live-front transformers in the area with dead-front 100 kVA transformers as shown in the scope map. Replace all secondary in the area with 350 aluminum conductor. Install secondary cabinets for every four services where feasible to improve system flexibility and maintainability. Replace one section of secondary prior to implementation under Notification 1072824896.
Estimated customer minutes saved =

Estimated Design Hours = 4029

Estimated Loaded Cost = $1,343,473

Miles = 4.44

Recommended Alternative:

Alternative # 1 is recommended

This project is primarily focused on reducing outage duration (CAIDI) and the number of customers affected during each event, rather than outage frequency.

Alternative 1 is the only option that materially improves outage duration, customer impact, and operational safety by correcting the underlying causes of long restorations at Ferrand Estates.

Key Benefits

Reduced CAIDI: By eliminating buried secondary connections and adding accessible isolation points, crews can locate and repair faults faster and restore portions of the park while work continues.
Reduced Customer Minutes Interrupted: Improved sectionalization and an added loop tie significantly reduce the number of customers affected during outages, lowering total customer minutes interrupted.
Improved Reliability: Removal of vintage primary and failure-prone secondary infrastructure reduces repeat outages and ongoing emergency response.
Improved Safety: Replacement of live-front transformers with modern dead-front equipment reduces crew

exposure and restoration risk.
Planned vs. Reactive Work: Converts ongoing fail-order and emergency repairs into a durable, maintainable system design.

Comparison to Other Alternatives

Alternative 3 (~$1.34M): Improves transformer safety and replaces secondary, but leaves vintage primary in service and does not improve sectionalization. Primary failure risk and long outage durations remain.
Alternative 2 (~$1.63M): Replaces primary, secondary, and transformers, but does not address system sectionalization or access limitations. Outage footprints and restoration challenges largely persist.
Alternative 1 (~$2.05M): Higher upfront cost, but the only alternative that delivers meaningful reductions in CAIDI and CMI, addresses safety concerns, and reduces long-term operational risk.

Cost/Benefit Summary
While Alternative 1 requires a higher initial investment, it provides the greatest long-term value by:

Reducing outage duration and customer impact
Lowering emergency O&M and fail-order activity
Improving system safety and maintainability
Aligning with the company's vintage underground replacement strategy and rate-case reliability objectives

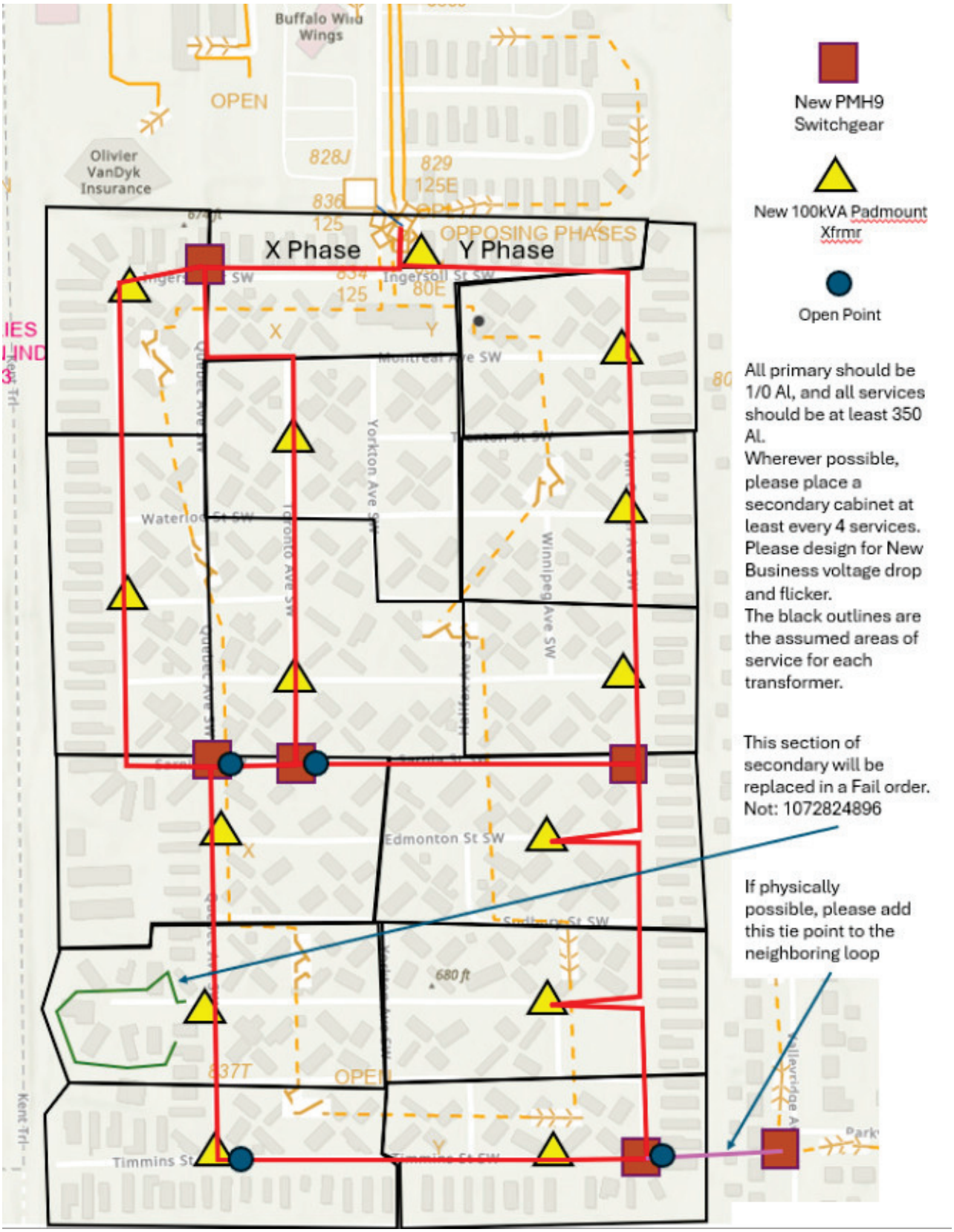
Conceptual Estimate

Program	Notification#	Loaded Cost	Plan Year	Description
2.16 Lines Rehabilitation - LVD	1072892823	$ 2053901	2027	
Project Total		**$2,053,901**		

Scope of Work:

Approvals

System Engineer	**Collin J. Hubbell 1**	**Approved**	**3/31/2026**
DIR LVD System Planning - West	**RACHEL D. SALL**		**3/31/2026**
Executive Director Electric Planning	**Gregory R. Griffin**		**3/31/2026**


Buffalo Wild Wings
OPEN
Olivier VanDyk Insurance
828J
829
125E
836
125
OPPOSING PHASES
X Phase
Y Phase
834
125
80E
Ingersoll St SW
Montreal Ave SW
Yorkton Ave SW
Toronto Ave SW
Winnipeg Ave SW
Edmonton St SW
680 ft
837T
OPEN
Timmins St
Kent Trl
New PMH9 Switchgear
New 100kVA Padmount Xfrmr
Open Point
All primary should be 1/0 Al, and all services should be at least 350 Al.
Wherever possible, please place a secondary cabinet at least every 4 services.
Please design for New Business voltage drop and flicker.
The black outlines are the assumed areas of service for each transformer.
This section of secondary will be replaced in a Fail order. Not: 1072824896
If physically possible, please add this tie point to the neighboring loop

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Overhead to Underground Project Benefit Cost Analyses (BCA)

Case No.: U-22070
Exhibit No.: A-172 (JMP-6)
Page: 1 of 1
Witness: JMPartlan
Date: June 2026

BCA >1: Underground provides greater value to customers than alternative of traditional hardening

	Project	Feeder Length (Miles)	Underground Cost ($k/Mile)	Total Spend ($k)	BCA
1	Greenwood_M-33_606	1.5	550	825	1.50
2	Greenwood_M-33_819	2.5	400	1,000	1.95
3	Balcom_Bankers_736	1.2	350	420	1.95
4	Blue Star_Pier Cove_622	1.7	550	935	1.04
5	Bricker_Storey Road_228	5.1	375	1,913	1.55
6	Brooklyn_Brooklyn_811	0.3	600	180	1.54
7	Casco_Hawkhead_516	0.7	410	287	1.77
8	Dean Road_Hartland_951	2.0	450	900	1.31
9	Halls Lake_Halls Lake_173	2.3	510	1,173	1.06
10	Hanover_Pulaski_532	4.2	400	1,680	1.31
11	Harvard Lake_Harvard Lake_986	5.9	380	2,242	1.27
12	Kolassa_Matteson_187	0.8	600	480	1.27
13	Lake Leann_Lake Leann_159	1.0	540	540	1.37
14	Lake Leann_Lake Leann_282	0.7	420	294	1.48
15	Maple Grove_Summitave _ 289	0.7	420	294	1.42
16	Northport_Manitou_657	2.0	350	700	1.84
17	Oak Street_Cooper Street_211	1.2	375	450	1.54
18	Peninsula_Mapleton_124	1.6	450	720	1.18
19	Sherman_Sherman_0304	4.4	300	1,320	1.83
20	Spruce Road_East Bay_0693	0.9	450	405	1.19
21	Spruce Road_East Bay_0868	0.7	400	280	2.39
22	Whittemore_Bear Paw_28	0.9	300	270	1.98
23	Yorkville_Highland Park_182	1.3	400	520	1.37
24	Gerrish_Merrio_248	4.9	280	1,372	1.23
		48.5	396	$ 19,200	

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

HANNAH L. PATTON

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Schedule: A-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Deficiency (Sufficiency)
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-1 (HLP-1)
Schedule: A-1
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Source	(c) Total Amount
1	Rate base	Exhibit No.: A-2 (HLP-3)	15,041,063
2	Adjusted net operating income	Exhibit No.: A-3 (HLP-9)	893,051
3	Overall rate of return	Line 2 / Line 1	5.94%
4	Required rate of return	Exhibit No.: A-4 (HLP-23)	5.91%
5	Income requirements	Line 1 * Line 4	888,507
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	(4,544)
7	Revenue conversion factor	Exhibit No.: A-3 (HLP-10)	1.3381
8	Revenue Deficiency (sufficiency)	Line 6 * Line 7	(6,080)

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Financial Basis
ELECTRIC RESULTS ONLY
($000)

Case No.: U-22070
Exhibit No.: A-1 (HLP-2)
Schedule: A-2

Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) 2021	(c) 2022	(d) 2023	(e) 2024	(f) 2025
		Calendar Year				
1	Operating revenues	4,957,857	5,419,082	4,745,364	5,061,475	5,637,870
2	Operating expenses	4,156,834	4,630,615	3,973,704	4,079,442	4,539,330
3	Pre-tax operating income	801,024	788,467	771,660	982,033	1,098,540
4	Income taxes	117,193	108,800	66,100	101,842	150,268
5	Net operating income	683,831	679,667	705,560	880,191	948,272
6	Other income and deductions	83,027	102,863	128,080	109,035	113,766
7	AFUDC	8,207	5,520	3,493	24,362	14,908
8	Interest charges	(193,601)	(206,904)	(273,930)	(319,881)	(344,480)
9	Preferred stock dividends	(1,081)	(1,078)	(1,040)	(1,008)	(1,016)
10	Net income available to common stockholders	580,383	580,068	562,163	692,699	731,451
11	Average common equity	6,260,365	6,372,772	6,607,356	6,893,776	7,450,786
12	Earned rate of return on common equity	9.27%	9.10%	8.51%	10.05%	9.82%
13	Authorized rate of return on common equity	9.90% {1}	9.90% {2}	9.90% {3}	9.90% {4}	9.90% {5}

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Financial Basis
ELECTRIC RESULTS ONLY
($000)

Case No.: U-22070
Exhibit No.: A-1 (HLP-2)
Schedule: A-2
Page: 2 of 6
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) 2021	(c) 2022	(d) 2023	(e) 2024	(f) 2025
				Calendar Year		
	EBIT Interest Coverage Ratio					
14	Pre-tax operating income	801,024	788,467	771,660	982,033	1,098,540
15	Other income and deductions	83,027	102,863	128,080	109,035	113,766
16	AFUDC	8,207	5,520	3,493	24,362	14,908
17	Total EBIT	892,257	896,850	903,232	1,115,430	1,227,215
18	Interest charges	193,601	206,904	273,930	319,881	344,480
19	EBIT interest coverage ratio	4.61	4.33	3.30	3.49	3.56
	EBITDA Interest Coverage Ratio					
20	Total EBIT	892,257	896,850	903,232	1,115,430	1,227,215
21	Depreciation and amortization	771,634	757,258	797,668	865,050	903,244
22	Total EBITDA	1,663,891	1,654,108	1,700,901	1,980,480	2,130,458
23	Interest charges	193,601	206,904	273,930	319,881	344,480
24	EBITDA interest coverage ratio	8.59	7.99	6.21	6.19	6.18
	Funds Flow from Operations (FFO) Interest Coverage Ratio					
25	Net operating income	683,831	679,667	705,560	880,191	948,272
26	Depreciation and amortization	771,634	757,258	797,668	865,050	903,244
27	Deferred income taxes	(85,580)	166,168	72,405	(36,010)	88,578
28	AFUDC	8,207	5,520	3,493	24,362	14,908
29	Other major recurring non-cash items	-	-	-	-	-
30	Interest paid	198,499	202,104	266,171	300,719	314,813
	Less:					
31	Operating lease adjustment to depreciation	-	-	-	-	-
32	Subtotal	1,576,591	1,810,716	1,845,297	2,034,313	2,269,815
33	Interest charges	193,601	206,904	273,930	319,881	344,480
34	FFO interest coverage ratio	8.14	8.75	6.74	6.36	6.59

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Financial Basis
ELECTRIC RESULTS ONLY
($000)

Case No.: U-22070
Exhibit No.: A-1 (HLP-2)
Schedule: A-2
Page: 3 of 6
Witness: HLPatton
Date: June 2026

Line No	Description	Calendar Year 2021	2022	2023	2024	2025
		(a)	(b)	(c)	(d)	(e)	(f)
	Overall Fixed Charge Coverage Ratio					
35	Net income available to common stockholders	580,383	580,068	562,163	692,699	731,451
36	Interest charges	193,601	206,904	273,930	319,881	344,480
37	Subtotal numerator	773,984	786,972	836,092	1,012,580	1,075,930
38	Interest charges	193,601	206,904	273,930	319,881	344,480
39	Preferred stock dividends	1,081	1,078	1,040	1,008	1,016
40	Subtotal denominator	194,682	207,982	274,970	320,889	345,496
41	Overall fixed charge coverage ratio	3.98	3.78	3.04	3.16	3.11
	Cash Flow Coverage of Dividends Ratio					
42	Net income available to common stockholders	580,383	580,068	562,163	692,699	731,451
43	Depreciation and amortization	771,634	757,258	797,668	865,050	903,244
44	Deferred income taxes	(85,580)	166,168	72,405	(36,010)	88,578
45	Subtotal	1,266,437	1,503,494	1,432,236	1,521,739	1,723,272
46	Common dividends {6}	464,306	464,055	449,730	554,159	585,160
47	Cash flow coverage of dividends ratio	2.73	3.24	3.18	2.75	2.94
	Common Dividend Payout Ratio					
48	Common dividends {6}	464,306	464,055	449,730	554,159	585,160
49	Net income available to common stockholders	580,383	580,068	562,163	692,699	731,451
50	Common dividend payout ratio	80%	80%	80%	80%	80%
	Permanent Capitalization					
51	Long term debt	8,437,664	10,208,351	11,160,087	11,996,890	12,986,004
52	Preferred stock	37,315	37,315	37,315	37,315	37,315
53	Common equity	9,242,745	10,118,365	10,763,382	11,393,664	12,549,193
54	Total permanent capital	17,717,724	20,364,031	21,960,785	23,427,869	25,572,511
55	Long term debt	47.62%	50.13%	50.82%	51.21%	50.78%
56	Preferred stock	0.21%	0.18%	0.17%	0.16%	0.15%
57	Common equity	52.17%	49.69%	49.01%	48.63%	49.07%
58	Total permanent capital	100.00%	100.00%	100.00%	100.00%	100.00%

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
ELECTRIC RESULTS ONLY
($000)

Case No.: U-22070
Exhibit No.: A-1 (HLP-2)
Schedule: A-2

Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) 2021	(c) 2022	(d) 2023	(e) 2024	(f) 2025
		Calendar Year				
59	Operating revenues	4,884,658	5,228,924	4,634,761	4,837,892	5,298,077
60	Operating expenses	4,219,304	4,515,341	3,830,317	3,977,957	4,334,839
61	Pre-tax operating income	665,354	713,583	804,444	859,934	963,238
62	Income taxes	34,134	57,803	30,582	41,457	73,216
63	Net operating income	631,220	655,781	773,862	818,478	890,021
64	Tax impact of pro forma interest on NOI	(4,444)	(4,034)	(8,406)	(9,144)	(11,879)
65	AFUDC	8,166	5,491	3,475	24,244	14,908
66	Interest charges	(166,478)	(184,127)	(235,080)	(250,433)	(267,698)
67	Preferred stock dividends	(973)	(931)	(924)	(904)	(884)
68	Net income available to common stockholders and JDITC	467,492	472,180	532,926	582,241	624,468
69	Return assignable to JDITC	(3,428)	(3,651)	(3,530)	(3,265)	(3,098)
70	Net income available to common stockholders	464,064	468,529	529,395	578,976	621,371
71	Average common equity	5,189,180	5,480,655	5,764,013	5,863,574	6,230,573
72	Earned rate of return on common equity	8.94%	8.55%	9.18%	9.87%	9.97%
73	Authorized return on equity	9.90% {1}	9.90% {2}	9.90% {3}	9.90% {4}	9.90% {5}

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
ELECTRIC RESULTS ONLY
($000)

Case No.: U-22070
Exhibit No.: A-1 (HLP-2)
Schedule: A-2
Page: 5 of 6
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) 2021	(c) 2022	(d) 2023	(e) 2024	(f) 2025
				Calendar Year		
	EBIT Interest Coverage Ratio					
74	Pre-tax operating income	665,354	713,583	804,444	859,934	963,238
75	AFUDC	8,166	5,491	3,475	24,244	14,908
76	Total EBIT	673,520	719,075	807,919	884,179	978,146
77	Interest charges, net of pro forma interest	162,034	180,093	226,674	241,289	255,820
78	EBIT interest coverage ratio	4.16	3.99	3.56	3.66	3.82
	EBITDA Interest Coverage Ratio					
79	Total EBIT	673,520	719,075	807,919	884,179	978,146
80	Depreciation and amortization	751,470	748,017	783,248	881,096	795,876
81	Total EBITDA	1,424,990	1,467,092	1,591,166	1,765,275	1,774,022
82	Interest charges, net of pro forma interest	162,034	180,093	226,674	241,289	255,820
83	EBITDA interest coverage ratio	8.79	8.15	7.02	7.32	6.93
	Funds Flow from Operations (FFO) Interest Coverage Ratio					
84	Net operating income	631,220	655,781	773,862	818,478	890,021
85	Depreciation and amortization	751,470	748,017	783,248	881,096	795,876
86	Deferred income tax	(85,580)	166,168	72,405	(36,010)	88,578
87	AFUDC	8,166	5,491	3,475	24,244	14,908
88	Other major recurring non-cash items	-	-	-	-	-
89	Interest paid	198,499	202,104	266,171	300,719	314,813
	Less:					
90	Operating lease adjustment to depreciation	-	-	-	-	-
91	Subtotal	1,503,775	1,777,561	1,899,160	1,988,527	2,104,197
92	Interest charges, net of pro forma interest	162,034	180,093	226,674	241,289	255,820
93	FFO interest coverage ratio	9.28	9.87	8.38	8.24	8.23
	Overall Fixed Charge Coverage Ratio					
94	Net income available to common stockholders	464,064	468,529	529,395	578,976	621,371
95	Interest charges, net of pro forma interest	162,034	180,093	226,674	241,289	255,820
96	Subtotal numerator	626,098	648,623	756,069	820,265	877,190
97	Interest charges, net of pro forma interest	162,034	180,093	226,674	241,289	255,820
98	Preferred stock dividends	973	931	924	904	884
99	Subtotal denominator	163,007	181,025	227,598	242,193	256,704
100	Overall fixed charge coverage ratio	3.84	3.58	3.32	3.39	3.42

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
ELECTRIC RESULTS ONLY
($000)

Case No.: U-22070
Exhibit No.: A-1 (HLP-2)
Schedule: A-2
Page: 6 of 6
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) 2021	(c) 2022	(d) 2023	(e) 2024	(f) 2025
				Calendar Year		
	Cash Flow Coverage of Dividends Ratio					
101	Net income available to common stockholders	464,064	468,529	529,395	578,976	621,371
102	Depreciation and amortization	751,470	748,017	783,248	881,096	795,876
103	Deferred income tax	(85,580)	166,168	72,405	(36,010)	88,578
104	Subtotal	1,129,954	1,382,714	1,385,048	1,424,061	1,505,825
105	Common dividends {6}	371,251	374,824	423,516	463,180	497,097
106	Cash flow coverage of dividends ratio	3.04	3.69	3.27	3.07	3.03
	Common Dividend Payout Ratio					
107	Common dividends {6}	371,251	374,824	423,516	463,180	497,097
108	Net income available to common stockholders	464,064	468,529	529,395	578,976	621,371
109	Common Dividend Payout Ratio	80%	80%	80%	80%	80%
	Permanent Capitalization					
110	Long term debt, excluding securitization	8,214,999	9,009,833	10,397,193	11,391,866	12,514,077
111	Preferred stock	37,315	37,315	37,315	37,315	37,315
112	Common equity	9,274,520	10,133,854	10,778,709	11,405,304	12,556,018
113	Total permanent capital	17,526,834	19,181,001	21,213,217	22,834,485	25,107,410
114	Long term debt, excluding securitization	46.87%	46.97%	49.01%	49.89%	49.84%
115	Preferred stock	0.21%	0.19%	0.18%	0.16%	0.15%
116	Common equity	52.92%	52.83%	50.81%	49.95%	50.01%
117	Total permanent capital	100.00%	100.00%	100.00%	100.00%	100.00%

Notes

{1} Case No. U-20697 final order dated December 17, 2020; effective January 1, 2021
{2} Case No. U-20963 final order dated December 22, 2021; effective January 1, 2022
{3} Case No. U-21224 settlement agreement dated January 19, 2023; effective January 20, 2023
{4} Case No. U-21389 final order dated March 1, 2024; effective March 15, 2024
{5} Case No. U-21585 final order dated March 21, 2025; effective April 4, 2025
{6} CECo pays dividends to the parent as a total company. This number represents the company's 80% dividend policy applied to net income available to common stockholders

Schedule: B-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Rate Base
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-2 (HLP-3)
Schedule: B-1
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Source	(d) Total Amount
1	Total utility plant	Exhibit No.: A-2 (HLP-4)	17,906,245
2	Depreciation reserve	Exhibit No.: A-2 (HLP-5)	6,101,306
3	Net utility plant	Line 1 - Line 2	11,804,940
4	Customer advances for construction	Exhibit No.: A-2 (HLP-7), Column (e.1), Line 29	(72,670)
5	Utility plant rate base	Sum Lines 3 - 4	11,732,269
6	Working capital	Exhibit No.: A-2 (HLP-6)	3,308,793
7	Total rate base	Line 5 + Line 6	15,041,063

Schedule: B-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Utility Plant
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-2 (HLP-4)
Schedule: B-2
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) FERC Account Number	(c) Source	(d) Total Amount
1	Gross plant, including plant held for future use	101, 105	Exhibit No.: A-2 (HLP-7), Column (e.1), Line 3	18,981,084
2	Exclude: plant-in-service - renewable plant	101	WP-HLP-8	(1,725,636)
3	Deferred debits	182	WP-HLP-10	-
4	Construction work in progress	107	Exhibit No.: A-2 (HLP-7), Column (e.1), Line 7	1,699,316
5	Exclude: construction work in progress - renewable plan	107	WP-HLP-8	(1,048,519)
6	Total utility plant		Sum Lines 1 - 5	17,906,245

Schedule: B-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation Reserve and Other Deductions
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-2 (HLP-5)
Schedule: B-3
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Source	(c) Total Amount
1	Accumulated depreciation, amortization and depletion of plant-in-service	Exhibit No.: A-2 (HLP-7), Column (e.1), Line 6	5,135,080
2	Add: cost of removal regulatory liability	WP-HLP-10	1,308,711
3	Exclude: depreciation reserve - renewable plan	WP-HLP-8	(342,486)
4	Total depreciation reserve and other deductions	Sum Lines 1 - 3	6,101,306

Schedule: B-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Working Capital
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-2 (HLP-6)
Schedule: B-4
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Cash, cash equivalents, and restricted cash	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 10	142,570
2	Accounts and notes receivable	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 11	345,983
3	Fuel stock	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 12	25,098
4	Materials and supplies	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 13	251,263
5	Allowances	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 14	14
6	Prepayments	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 16	1,066,624
7	Accrued revenue	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 17	347,636
8	Deferred taxes	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 18	283,834
9	Deferred debits	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 19	2,104,763
10	Total assets	Sum Lines 1 - 9	4,567,785
11	Accounts payable	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 23	612,195
12	Customer deposits	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 24	26,644
13	Accrued interest	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 25	73,846
14	Dividends payable	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 26	29,263
15	Accrued taxes	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 27	347,287
16	Other liabilities	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 28	80,233
17	Deferred credits	Exhibit No.: A-2 (HLP-7), Column (f.1), Line 31	89,525
18	Total liabilities	Sum Lines 11 - 17	1,258,992
19	Total working capital	Line 10 - Line 18	3,308,793

Schedule: B-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
13-Month Average Balance Sheet
For the Historical Year Ended December 31, 2025
(In Dollars)

Case No.: U-22070
Exhibit No.: A-2 (HLP-7)
Schedule: B-5
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Source: WP-HLP-10

	(a)	(b)	(c.1)	(c.2)	(d.1)	(d.2)	(d.3)	(d.4)	(d.5)	(e.1)	(e.2)	(e.3)	(e.4)	(f.1)	(f.2)	(f.3)
			EXCLUDED		CAPITAL STRUCTURE					PLANT				WORKING CAPITAL		
Line No.	Description	Total	Rate Base	Sub. Invest.	Long-Term Debt	Short-Term Debt	ITC	Deferred Taxes	Equity	Electric	Gas	MGP	Non-Utility	Electric	Gas	Non-Utility
1	Utility plant	$31,930,114,650	$ 803,193,163	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,212,352,763	$ 12,914,568,723	$ -	$ -	$ -	$ -	$ -
2	Common plant	1,302,743,345	1,699,261	-	-	-	-	-	-	768,731,374	532,312,710	-	-	-	-	-
3	Gross plant	33,232,857,995	804,892,424	-	-	-	-	-	-	18,981,084,137	13,446,881,434	-	-	-	-	-
4	Utility plant accumulated depreciation	(7,603,331,704)	(310,587,189)	-	-	-	-	-	-	(4,650,192,440)	(2,642,552,075)	-	-	-	-	-
5	Common plant accumulated depreciation	(809,818,820)	(6,277,031)	-	-	-	-	-	-	(484,887,994)	(318,653,795)	-	-	-	-	-
6	Total depreciation	(8,413,150,523)	(316,864,220)	-	-	-	-	-	-	(5,135,080,433)	(2,961,205,871)	-	-			
7	Construction work in progress	2,220,330,705	-	-	-	-	-	-	-	1,699,316,286	521,014,419	-	-	-	-	-
8	Net plant	27,040,038,176	488,028,205	-	-	-	-	-	-	15,545,319,990	11,006,689,982	-	-	-	-	-
9	Other property	155,766,839	117,078,413	(6,956,300)	-	-	-	-	-	-	-	-	21,175,054	-	-	24,469,671
10	Cash, cash equivalents, and restricted cash	204,777,160	4,272,776	-	-	-	-	-	-	-	-	-	-	142,569,875	57,934,509	-
11	Accounts and notes receivable	501,663,265	14,361,587	-	-	-	-	-	-	-	-	-	-	345,983,138	130,386,606	10,931,935
12	Fuel stock	25,097,801	-	-	-	-	-	-	-	-	-	-	-	25,097,801	-	-
13	Materials and supplies	306,578,140	21	-	-	-	-	-	-	-	-	-	-	251,263,162	55,314,957	-
14	Allowances	8,824,621	8,810,333	-	-	-	-	-	-	-	-	-	-	14,288	-	-
15	Gas stored underground	416,942,218	-	-	-	-	-	-	-	-	-	-	-	-	416,942,218	-
16	Prepayments	1,709,886,408	5,570,637	-	-	-	-	-	-	-	-	-	-	1,066,623,837	637,691,935	-
17	Accrued revenue	534,705,833	32,886,165	-	-	-	-	-	-	-	-	-	-	347,635,949	154,183,720	-
18	Deferred taxes	2,206,219,463	119,691,231	-	-	-	-	1,601,738,382	-	-	-	-	-	283,833,731	200,633,034	323,085
19	Deferred debits	3,813,385,090	1,281,349,514	-	75,718,807	-	-	-	-	-	-	86,367,435	-	2,104,763,251	264,965,760	220,322
20	Total assets	36,923,885,014	2,072,048,882	(6,956,300)	75,718,807	-		1,601,738,382	-	15,545,319,990	11,006,689,982	86,367,435	21,175,054	4,567,785,031	1,918,052,739	35,945,013
21	Debt, leases, and financial obligations	(12,257,406,702)	(99,948,363)	-	(12,157,458,339)	-	-	-	-	-	-	-	-	-	-	-
22	Notes payable	(639,309,827)	(580,231,875)	-	-	(59,077,952)	-	-	-	-	-	-	-	-	-	-
23	Accounts payable	(990,860,550)	(1,790,000)	-	-	-	-	-	-	-	-	-	-	(612,194,643)	(368,674,372)	(8,201,536)
24	Customer deposits	(40,225,236)	-	-	-	-	-	-	-	-	-	-	-	(26,643,940)	(13,581,296)	-
25	Accrued interest	(130,378,170)	(8,339,394)	-	-	-	-	-	-	-	-	-	-	(73,845,663)	(47,900,220)	(292,893)
26	Dividends payable	(48,359,936)	-	-	-	-	-	-	-	-	-	-	-	(29,262,597)	(18,981,275)	(116,064)
27	Accrued taxes	(586,660,938)	-	-	-	-	-	-	-	-	-	-	-	(347,286,781)	(239,100,335)	(273,821)
28	Other liabilities	(246,234,009)	(138,522,854)	-	-	-	-	-	-	-	-	(2,579,414)	-	(80,232,600)	(24,899,141)	-
29	Customer advances	(92,617,111)	-	-	-	-	-	-	-	(72,670,161)	(19,946,950)	-	-	-	-	-
30	Deferred income and investment taxes	(6,096,050,040)	10,320,946	-	-	-	(120,095,224)	(5,986,275,762)	-	-	-	-	-	-	-	-
31	Deferred credits	(3,940,541,774)	(994,773,135)	-	-	(44,275,524)		-	-	(1,318,054,543)	(1,401,556,066)	(57,179,072)	-	(89,525,410)	(21,289,402)	(13,888,622)
32	Total liabilities	(25,068,644,293)	(1,813,284,675)	-	(12,157,458,339)	(103,353,476)	(120,095,224)	(5,986,275,762)	-	(1,390,724,703)	(1,421,503,016)	(59,758,486)	-	(1,258,991,634)	(734,426,040)	(22,772,936)
33	Common equity	(11,817,925,921)	11,045,955	-	-	-	-	-	(11,828,971,876)	-	-	-	-	-	-	-
34	Preferred stock	(37,314,800)	-	-	-	-	-	-	(37,314,800)	-	-	-	-	-	-	-
35	Total equity	(11,855,240,721)	11,045,955	-	-	-	-	-	(11,866,286,676)	-	-	-	-	-	-	-
36	Net assets (liabilities)	$ -	$ 269,810,161	$ (6,956,300)	$ (12,081,739,532)	$ (103,353,476)	$ (120,095,224)	$ (4,384,537,380)	$ (11,866,286,676)	$ 14,154,595,286	$ 9,585,186,966	$ 26,608,949	$ 21,175,054	$ 3,308,793,397	$ 1,183,626,698	$ 13,172,076

Schedule: B-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Point-In-Time Balance Sheet
For the Historical Year Ended December 31, 2025
(In Dollars)

Case No.: U-22070
Exhibit No.: A-2 (HLP-8)
Schedule: B-6
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Source: WP-HLP-9

	(a)	(b)	(c.1)	(c.2)	(d.1)	(d.2)	(d.3)	(d.4)	(d.5)	(e.1)	(e.2)	(e.3)	(e.4)	(f.1)	(f.2)	(f.3)
			EXCLUDED		CAPITAL STRUCTURE					PLANT				WORKING CAPITAL		
Line No.	Description	Total	Rate Base	Sub. Invest.	Long-Term Debt	Short-Term Debt	ITC	Deferred Taxes	Equity	Electric	Gas	MGP	Non-Utility	Electric	Gas	Non-Utility
1	Utility plant	$ 33,559,747,588	$ 898,603,797	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,195,297,438	$ 13,465,846,353	$ -	$ -	$ -	$ -	$ -
2	Common plant	1,293,905,849	1,065,408	-	-	-	-	-	-	763,884,192	528,956,249	-	-	-	-	-
3	Gross plant	34,853,653,437	899,669,205	-	-	-	-	-	-	19,959,181,630	13,994,802,602	-	-	-	-	-
4	Utility plant accumulated depreciation	(7,791,686,893)	(343,368,495)	-	-	-	-	-	-	(4,739,222,438)	(2,709,095,960)	-	-	-	-	-
5	Common plant accumulated depreciation	(798,514,163)	(6,871,394)	-	-	-	-	-	-	(477,713,477)	(313,929,292)	-	-	-	-	-
6	Total depreciation	(8,590,201,056)	(350,239,889)	-	-	-	-	-	-	(5,216,935,915)	(3,023,025,252)	-	-			
7	Construction work in progress	2,342,756,189	-	-	-	-	-	-	-	1,871,703,427	471,052,763	-	-	-	-	-
8	Net plant	28,606,208,570	549,429,316	-	-	-	-	-	-	16,613,949,141	11,442,830,113	-	-	-	-	-
9	Other property	154,368,721	117,639,306	(7,115,717)	-	-	-	-	-	-	-	-	19,375,461	-	-	24,469,671
10	Cash, cash equivalents, and restricted cash	21,247,454	3,649,179	-	-	-	-	-	-	-	-	-	-	12,513,361	5,084,913	-
11	Accounts and notes receivable	547,589,080	40,269,989	-	-	-	-	-	-	-	-	-	-	355,137,255	138,617,059	13,564,777
12	Fuel stock	30,960,682	-	-	-	-	-	-	-	-	-	-	-	30,960,682	-	-
13	Materials and supplies	315,858,890	21	-	-	-	-	-	-	-	-	-	-	258,551,316	57,307,554	-
14	Allowances	6,307,779	6,293,491	-	-	-	-	-	-	-	-	-	-	14,288	-	-
15	Gas stored underground	427,011,087	-	-	-	-	-	-	-	-	-	-	-	-	427,011,087	-
16	Prepayments	1,955,193,083	5,570,637	-	-	-	-	-	-	-	-	-	-	1,229,927,329	719,695,117	-
17	Accrued revenue	709,585,977	40,912,418	-	-	-	-	-	-	-	-	-	-	357,517,124	311,156,435	-
18	Deferred taxes	2,395,891,018	90,484,000	-	-	-	-	1,574,763,708	-	-	-	-	-	427,804,092	302,355,457	483,761
19	Deferred debits	3,715,243,585	1,349,700,782	-	75,738,176	-	-	-	-	-	-	82,424,984	-	1,993,481,558	213,681,085	217,001
20	Total assets	38,885,465,927	2,203,949,140	(7,115,717)	75,738,176	-		1,574,763,708	-	16,613,949,141	11,442,830,113	82,424,984	19,375,461	4,665,907,006	2,174,908,706	38,735,210
21	Debt, leases, and financial obligations	(12,694,869,767)	(105,054,373)	-	(12,589,815,394)	-	-	-	-	-	-	-	-	-	-	-
22	Notes payable	(857,486,601)	(517,486,601)	-	-	(340,000,000)	-	-	-	-	-	-	-	-	-	-
23	Accounts payable	(1,234,249,612)	-	-	-	-	-	-	-	-	-	-	-	(763,443,551)	(459,588,074)	(11,217,987)
24	Customer deposits	(40,024,738)	-	-	-	-	-	-	-	-	-	-	-	(26,396,513)	(13,628,224)	-
25	Accrued interest	(139,867,344)	(9,200,713)	-	-	-	-	-	-	-	-	-	-	(79,066,378)	(51,286,653)	(313,600)
26	Dividends payable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Accrued taxes	(814,614,020)	-	-	-	-	-	-	-	-	-	-	-	(480,559,663)	(333,590,241)	(464,116)
28	Other liabilities	(195,808,637)	(141,641,977)	-	-	-	-	-	-	-	-	(2,494,819)	-	(35,902,028)	(15,769,812)	-
29	Customer advances	(99,316,194)	-	-	-	-	-	-	-	(80,932,271)	(18,383,923)	-	-	-	-	-
30	Deferred income and investment taxes	(6,130,163,719)	17,521,690	-	-	-	(117,899,701)	(6,029,785,708)	-	-	-	-	-	-	-	-
31	Deferred credits	(4,092,557,923)	(1,164,756,051)	-	-	-	-	-	-	(1,310,738,497)	(1,426,458,256)	(56,939,798)	-	(97,284,633)	(22,906,034)	(13,474,654)
32	Total liabilities	(26,298,958,553)	(1,920,618,025)	-	(12,589,815,394)	(340,000,000)	(117,899,701)	(6,029,785,708)	-	(1,391,670,768)	(1,444,842,179)	(59,434,617)	-	(1,482,652,767)	(896,769,037)	(25,470,357)
33	Common equity	(12,549,192,574)	6,825,435	-	-	-	-	-	(12,556,018,009)	-	-	-	-	-	-	-
34	Preferred stock	(37,314,800)	-	-	-	-	-	-	(37,314,800)	-	-	-	-	-	-	-
35	Total equity	(12,586,507,374)	6,825,435	-	-	-	-	-	(12,593,332,809)	-	-	-	-	-	-	-
36	Net assets (liabilities)	$ -	$ 290,156,550	$ (7,115,717)	$ (12,514,077,218)	$ (340,000,000)	$ (117,899,701)	$ (4,455,022,000)	$ (12,593,332,809)	$ 15,222,278,373	$ 9,997,987,933	$ 22,990,367	$ 19,375,461	$ 3,183,254,239	$ 1,278,139,669	$ 13,264,853

Schedule: C-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-9)
Schedule: C-1
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Total Amount
1	Sales revenues	Exhibit No.: A-3 (HLP-11)	5,113,363
2	Sales for resale	Exhibit No.: A-3 (HLP-11)	140,455
3	Other electric revenues	Exhibit No.: A-3 (HLP-11)	268,285
4	Total operating revenues	Sum Lines 1 - 3	5,522,103
5	Fuel expense	Exhibit No.: A-3 (HLP-12)	535,586
6	Purchased & interchange power	Exhibit No.: A-3 (HLP-12)	1,670,309
7	Operations and maintenance	Exhibit No.: A-3 (HLP-13)	966,547
8	Depreciation and amortization	Exhibit No.: A-3 (HLP-15)	795,876
9	Property taxes	Exhibit No.: A-3 (HLP-16)	256,497
10	General taxes	Exhibit No.: A-3 (HLP-16)	38,736
11	Other (local) taxes	Exhibit No.: A-3 (HLP-19)	1,690
12	State income taxes	Exhibit No.: A-3 (HLP-18)	69,384
13	Federal income taxes	Exhibit No.: A-3 (HLP-17)	73,216
14	Total operating expenses	Sum Lines 5 - 13	4,407,840
15	Net operating income	Line 4 - Line 14	1,114,263
16	AFUDC	Exhibit No.: A-3 (HLP-20)	14,908
17	Net operating income, including AFUDC	Line 15 + Line 16	1,129,171
	Adjustments to Net Operating Income		
18	Weather normalization	Exhibit No.: A-13 (HLP-37), Line 2	(52,358)
19	Purchased power administration fee revenue	Exhibit No.: A-13 (HLP-37), Line 3	(604)
20	Surcharge Revenues and Other Adjustments	Exhibit No.: A-13 (HLP-37), Line 4	(175,796)
21	Jobwork revenues	Exhibit No.: A-13 (HLP-37), Line 5	1,389
22	Interest income on cash operating accounts	Exhibit No.: A-13 (HLP-37), Line 6	3,342
23	Excess MDNR fees	Exhibit No.: A-13 (HLP-37), Line 7	343
24	Compensation expenses	Exhibit No.: A-13 (HLP-37), Line 8	131
25	Advertising expenses	Exhibit No.: A-13 (HLP-37), Line 9	-
26	Dues & donations expenses	Exhibit No.: A-13 (HLP-37), Line 10	495
27	Jobwork expenses	Exhibit No.: A-13 (HLP-37), Line 11	(939)
28	Interest expense on security deposits	Exhibit No.: A-13 (HLP-37), Line 12	(244)
29	Income Tax Effect of Interest	Exhibit No.: A-13 (HLP-37), Line 13	(12,212)
30	Interest Synchronization Adjustment	Exhibit No.: A-13 (HLP-37), Line 14	333
31	Total net operating income adjustments	Sum Lines 18 - 30	(236,120)
32	Adjusted net operating income	Line 17 + Line 31	893,051

Schedule: C-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Conversion Factor
For the Historical Year Ended December 31, 2025

Case No.: U-22070
Exhibit No.: A-3 (HLP-10)
Schedule: C-2
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Income base - before taxes		100.0000
2	State income tax	Line 1 * 5.24% State Income Tax Rate	5.2400
3	Other (local) income tax	Line 1 * 0.16% Other (Local) Income Tax Rate	0.1600
4	Federal income tax base	Line 1 - Line 2 - Line 3	94.6000
5	Federal income tax	Line 4 * 21.00% Federal Income Tax Rate	19.8660
6	Income base - after taxes	Line 4 - Line 5	74.7340
7	Revenue conversion factor	Line 1 / Line 6	1.3381

Schedule: C-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operating Revenue
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-11)
Schedule: C-3
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Source	(c) Amount
1	Sales revenues	P-521, p. 300(M), Col. (b), Line 12 - P-521, p. 300(M), Col. (b), Line 17	5,113,363
2	Sales for resale	P-521, p. 300(M), Col. (b), Line 14	140,455
3	Other electric revenues	P-521, p. 300(M), Col. (b), Line 30	268,285
4	Total operating revenues	Sum Lines 1 - 3	5,522,103

Schedule: C-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Fuel and Purchased Power
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-12)
Schedule: C-4
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Fuel expense - Steam Power	P-521, p. 320, Line 5	136,138
2	Fuel expense - Other Power Generation	P-521, p. 320.1, Line 72	406,771
3	Fuel handling	WP-HLP-12	(7,262)
4	Excess MDNR Fees	WP-HLP-12	459
5	O&M expense - Included in Other Power Generation	Exhibit No.: A-3 (HLP-14)	(519)
6	Total Fuel Expense	Sum Lines 1 - 5	535,586
7	Purchased power	P-521, p. 320.1, Lines 88 through 91	1,099,279
8	Transmission expenses	P-521, p. 321, Line 162	562,993
9	Regional transmission and market operating expense	P-521, p. 322, Line 194	9,903
10	Industry Fees	WP-HLP-12	(1,866)
11	Total purchased and net interchange power	Sum Lines 7 - 10	1,670,309
12	Total cost of fuel and purchased power	Line 6 + Line 11	2,205,894

Schedule: C-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operation and Maintenance Expenses
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-13)
Schedule: C-5
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Power production expenses	P-521, p. 321, Line 143 - Exhibit No.: A-3 (HLP-12), Lines 6-7	173,514
2	Industry Fees	WP-HLP-12	1,866
3	Distribution expenses	P-521, p. 322, Line 238	434,682
4	Customer accounts expenses	P-521, p. 323, Line 246	68,887
5	Customer service & information expenses	P-521, p. 323, Line 253	261,151
6	Sales expenses	P-521, p. 323, Line 260	207
7	Administrative & general expenses	P-521, p. 323, Line 282	50,916
8	Subtotal	Sum Lines 1 - 7	991,224
9	Exclude: Electric Vehicle Amortization Expense	Exhibit No.: A-173 (HLP-51), Lines 8 + 15, column (h)	(6,363)
10	Exclude: Karn & Campbell Plant Retention & Separation Costs Amortization Expense	Exhibit No.: A-174 (HLP-52), Lines 5 + 11, column (g)	(18,235)
11	Exclude: Non-energy related uncollectibles expenses and uncollectible reserve activity	Exhibit No.: A-3 (HLP-13), Schedule: C-5.1	(2,066)
12	Include: EICP operational incentive goals	Exhibit No.: A-3 (HLP-13), Schedule: C-5.1	1,795
13	Include: cloud computing amortization included in O&M	Exhibit No.: A-3 (HLP-13), Schedule: C-5.1	192
14	Gains from disposition of allowances	P-521, p.115, Col. (g), Line 22	-
15	Total other operation and maintenance expenses	Sum Lines 8 - 14	966,547

Schedule: C-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Historical Operation and Maintenance Expenses by Witness
For the Historical Year Ended December 31, 2025
(In Dollars)

Case No.: U-22070
Exhibit No.: A-3 (HLP-14)
Schedule: C-5.1
Page: 1 of 2
Witness: HLPatton
Date: June 2026

Line No.	FERC Account	Description	IT Baker	Generation Wittbrodt	Forestry Stewart	Customer Experience, Demand Response Electric Vehicles Gast	Incentive Compensation Conrad	Other Patton	Corporate Foster	Employee Benefits Grob	Operations Support / Facilities Guinn	Distribution Duke	Total O&M	MPSC P-521	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(o)	(p)	(q)
16	95000010	(500) Operation Supervision and Engineering	$ 1,504,361	$ 3,901,554	$ -	$ -	$ -	0	$ 181,487	$ -	$ -	$ 37,257	$ 5,624,658	$ 7,759,574	$ 2,134,916
17	95011010	(501) Fuel	-	-	-	-	-	-	-	-	-	-	-	128,875,175	128,875,175
18	95012010	(501) Fuel - Nonfuel Clause	-	4,340,205	-	-	-	(0)	-	-	-	-	4,340,205	7,262,413	2,922,208
19	95020010	(502) Steam Expenses	-	6,322,751	-	-	-	-	-	-	-	-	6,322,751	10,760,331	4,437,580
20	95050010	(505) Electric Expenses	-	5,257,456	-	-	-	-	-	-	-	-	5,257,456	7,719,040	2,461,584
21	95060010	(506) Miscellaneous Steam Power Expenses	3,422,778	2,032,572	-	-	-	-	497,380	-	198,594	-	6,151,323	6,151,330	7
22	95100010	(510) Maintenance of Supervision and Engineering	-	1,948,079	-	-	-	-	80,523	-	-	-	2,028,602	3,051,248	1,022,646
23	95110010	(511) Maintenance of Structures	-	1,901,442	-	-	-	-	-	-	-	-	1,901,442	1,901,442	0
24	95120010	(512) Maintenance of Boiler Plant	-	6,650,146	-	-	-	-	-	-	-	-	6,650,146	12,163,583	5,513,437
25	95130010	(513) Maintenance of Electric Plant	-	5,414,661	-	-	-	-	-	-	-	-	5,414,661	5,412,276	(2,385)
26	95131010	(513.1) Maintenance of Computer Hardware	211,159	4,737	-	-	-	-	-	-	-	-	215,896	211,157	(4,739)
27	95132010	(513.2) Maintenance of Computer Software	2,358,568	272,007	-	-	-	-	-	-	-	-	2,630,574	2,509,957	(120,617)
28	95133010	(513.3) Maintenance of Communication Equipment	48,507	-	-	-	-	-	-	-	-	-	48,507	48,504	(3)
29	95140010	(514) Maintenance of Miscellaneous Steam Plant	-	441,684	-	-	-	-	-	-	-	-	441,684	441,684	(0)
30	95350010	(535) Operation Supervision and Engineering	678,058	1,382,282	-	-	-	-	96,640	-	-	17,773	2,174,752	2,193,085	18,333
31	95360010	(536) Water for Power	-	1,815,776	-	-	-	-	-	-	-	-	1,815,776	1,815,776	0
32	95370010	(537) Hydraulic Expenses	-	3,465,492	-	-	-	-	-	-	-	-	3,465,492	3,465,493	1
33	95380010	(538) Electric Expenses	-	1,635,258	-	-	-	-	-	-	-	-	1,635,258	1,635,258	(0)
34	95390010	(539) Miscellaneous Hydraulic Power Generation Expenses	246,168	539,171	-	-	-	-	239,872	-	37,442	-	1,062,652	1,062,652	(0)
35	95400010	(540) Rents	-	2,729	-	-	-	-	-	-	-	-	2,729	2,729	1
36	95410010	(541) Maintenance Supervision and Engineering	-	1,365,913	-	-	-	-	45,176	-	-	-	1,411,089	1,411,089	(0)
37	95420010	(542) Maintenance of Structure	-	682,208	-	-	-	-	-	-	-	-	682,208	682,208	0
38	95430010	(543) Maintenance of Reservoirs, Dams, and Waterways	-	2,971,256	-	-	-	-	-	-	-	-	2,971,256	2,971,255	(1)
39	95440010	(544) Maintenance of Electric Plant	-	3,008,564	-	-	-	-	-	-	-	-	3,008,564	3,008,564	0
40	95441010	(544.1) Maintenance of Computer Hardware	32,524	-	-	-	-	-	-	-	-	-	32,524	32,522	(2)
41	95442010	(544.2) Maintenance of Computer Software	364,564	-	-	-	-	-	-	-	-	-	364,564	364,563	(1)
42	95443010	(544.3) Maintenance of Communication Equipment	7,471	49	-	-	-	-	-	-	-	-	7,520	7,512	(8)
43	95450010	(545) Maintenance of Miscellaneous Hydraulic Plant	-	6,269,293	-	-	-	-	-	-	-	-	6,269,293	6,269,294	1
44	95460010	(546) Operation Supervision and Engineering	599,061	1,575,953	-	-	-	-	279,993	-	21,245	24,958	2,501,211	2,482,873	(18,338)
45	95470010	(547) Fuel	-	519,491	-	-	-	-	-	-	-	-	519,491	406,770,775	406,251,284
46	95480010	(548) Generation Expenses	-	9,735,348	-	-	-	-	-	-	-	-	9,735,348	9,853,937	118,589
47	95490010	(549) Miscellaneous Other Power Generation Expenses	-	2,719,493	-	-	-	-	-	-	-	-	2,719,493	2,719,493	(0)
48	95500010	(550) Rents	-	8,353	-	-	-	-	-	-	-	-	8,353	8,353	(0)
49	95510010	(551) Maintenance Supervision and Engineering	-	1,478,236	-	-	-	-	94,904	-	-	-	1,573,140	1,573,139	(1)
50	95520010	(552) Maintenance of Structures	-	274,066	-	-	-	-	-	-	-	-	274,066	274,066	(0)
51	95530010	(553) Maintenance of Generating and Electric Plant	-	25,493,247	-	-	-	-	-	-	-	-	25,493,247	25,493,248	1
52	95531010	(553.1) Maintenance of Computer Hardware	28,739	-	-	-	-	-	-	-	-	-	28,739	33,473	4,734
53	95532010	(553.2) Maintenance of Computer Software	323,511	-	-	-	-	-	-	-	-	-	323,511	444,118	120,607
54	95533010	(553.3) Maintenance of Communication Equipment	6,602	-	-	-	-	-	-	-	-	-	6,602	6,597	(5)
55	95540010	(554) Maintenance of Miscellaneous Other Power Generation Plant	-	26,514	-	-	-	-	-	-	-	-	26,514	26,514	0
56	95550010	(555) Purchased Power	-	-	-	-	-	-	-	-	-	-	-	1,086,116,260	1,086,116,260
57	95551010	(555.1) Power Purchased for Storage Operations	-	-	-	-	-	-	-	-	-	-	-	1,576,658	1,576,658
58	95552010	(555.2) Bundled Environmental Credits	-	-	-	-	-	-	-	-	-	-	-	11,532,847	11,532,847
59	95553010	(555.3) Unbundled Environmental Credits	-	-	-	-	-	-	-	-	-	-	-	53,286	53,286
60	95560010	(556) System Control and Load Dispatching	1,074,970	6,058,196	-	-	-	-	-	-	-	450,162	7,583,329	7,583,329	0
61	95581010	(558.1) Operation Supervision and Engineering	0	(0)	-	-	-	-	-	-	-	3,403	3,403	814,728	811,325
62	95582010	(558.2) Solar Panel Generation and Other Plant Operating Expenses	-	(0)	-	-	-	-	-	-	-	-	(0)	4,391,266	4,391,266
63	95586010	(558.6) Maintenance Supervision and Engineering	-	0	-	-	-	-	-	-	-	-	0	484,606	484,606
64	95588010	(558.8) Maintenance of Computer Hardware	-	-	-	-	-	-	-	-	-	-	-	287	287
65	95589010	(558.9) Maintenance of Computer Software	0	-	-	-	-	-	-	-	-	-	0	11,929	11,929
66	95589011	(558.10) Maintenance of Computer Equipment	-	-	-	-	-	-	-	-	-	-	-	237	237
67	95581200	(558.11) Maintenance of Miscellaneous Solar Generation Plant	-	(0)	-	-	-	-	-	-	-	-	-	866,382	866,382
68	95581300	(558.13) Operation Supervision and Engineering	0	0	-	-	-	-	1,643	-	-	24,580	26,223	2,344,928	2,318,705
69	95581400	(558.14) Wind Turbine Generation and Other Plant Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	5,711,387	5,711,387
70	95581600	(558.16) Rents	-	0	-	-	-	-	-	-	-	-	0	2	2
71	95581800	(558.18) Maintenance Supervision and Engineering	-	0	-	-	-	-	-	-	-	-	0	879,628	879,628
72	95581900	(558.19) Maintenance of Wind Turbines, Structures, and Equipment	-	0	-	-	-	-	-	-	-	-	0	556,315	556,315
73	95582000	(558.20) Maintenance of Computer Hardware	-	-	-	-	-	-	-	-	-	-	-	1,680	1,680
74	95582100	(558.21) Maintenance of Computer Software	(0)	-	-	-	-	-	-	-	-	-	(0)	234,391	234,391
75	95582200	(558.22) Maintenance of Communication Equipment	0	-	-	-	-	-	-	-	-	-	0	26,543	26,543
76	95582300	(558.23) Maintenance of Miscellaneous Wind Generation Plant	-	-	-	-	-	-	-	-	-	-	-	15,508,960	15,508,960
77	95582400	account not used after FERC 898, residual reclass activity for 2025	-	(0)	-	-	-	-	-	-	-	-	(0)	-	0
78	95585010	account not used after FERC 898, residual reclass activity for 2025	-	-	-	-	-	-	-	-	-	-	-	-	-
79	95591200	(559.10) Maintenance of Generating and Electric Equipment	-	266	-	-	-	-	-	-	-	-	266	-	(266)
80	95591300	(559.12) Maintenance of Computer Hardware	-	806,157	-	-	-	-	-	-	-	-	806,157	266	(805,891)
81	95591400	(559.13) Maintenance of Computer Software	-	295	-	-	-	-	-	-	-	-	295	806,157	805,862
82	95591401	(559.14) Maintenance of Communication Equipment	-	-	-	-	-	-	-	-	-	-	-	295	295
83	95614010	(561.4) Scheduling, System Control and Dispatch Services	-	-	-	-	-	-	-	-	-	-	-	14,945,961	14,945,961
84	95616000	(561.6) Transmission Service Studies	-	-	-	-	-	-	-	-	-	-	-	20,000	20,000
85	95618010	(561.8) Reliability, Planning and Standards Development Services	-	-	-	-	-	-	-	-	-	1,866,264	1,866,264	2,492,927	626,663
86	95650010	(565) Transmission of Electricity by Others	-	-	-	-	-	-	-	-	-	-	-	545,533,861	545,533,861
87	95757010	(575.7) Market Facilitation, Monitoring and Compliance Services	-	-	-	-	-	-	-	-	-	-	-	9,903,190	9,903,190
88	95771010	(577.1) Operation Supervision and Engineering	-	709,750	-	-	-	-	-	-	-	-	709,750	709,750	(0)
89	95781010	(578.1) Maintenance Supervision and Engineering	-	242,381	-	-	-	-	-	-	-	-	242,381	235,228	(7,153)
90	95782010	(578.2) Maintenance of Energy Storage Equipment and Structures	-	91,091	-	-	-	-	-	-	-	-	91,091	91,092	1
91	95800010	(580) Operation Supervision and Engineering	10,933,180	202,696	5,109,125	-	-	-	1,009,862	-	16,631	1,079,305	18,350,798	18,449,896	99,098
92	95820010	(582) Station Expenses	-	-	-	-	-	-	-	-	-	1,415,538	1,415,538	1,415,538	(0)
93	95830010	(583) Overhead Line Expenses	-	-	-	-	-	-	-	-	-	50,074,500	50,074,500	50,074,501	1
94	95840010	(584) Underground Line Expenses	-	-	-	-	-	-	-	-	-	12,015,781	12,015,781	12,015,780	(1)

Schedule C5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Historical Operation and Maintenance Expenses by Witness
For the Historical Year Ended December 31, 2025

Case No.: U-22070
Exhibit No.: A-3 (HLP-14)
Schedule: C-5.1
Page: 2 of 2
Witness: HLPatton
Date: June 2026

Line No.	FERC Account	Description	Baker	Wittbrodt	Stewart	Gast	Conrad	Patton	Foster	Grob	Guinn	Duke	Total O&M	MPSC P-521 Pg 320-323	Variance
95	95841010	(584.1) Ops Engineering Storage Equip	-	-	-	-	-	-	-	-	-	-	-	-	
96	95850010	(585) Street Lighting and Signal System Expenses	-	-	-	-	-	-	-	-	-	2,164,040	2,164,040	2,164,038	(2)
97	95860010	(586) Meter Expenses	-	-	-	-	-	-	-	-	-	1,992,556	1,992,556	1,992,556	0
98	95870010	(587) Customer Installations Expenses	-	-	-	-	-	-	-	-	-	9,110,665	9,110,665	9,110,664	(0)
99	95880010	(588) Miscellaneous Expenses	-	461,636	-	-	-	-	2,855,554	-	4,191,807	19,286,628	26,795,625	26,795,625	0
100	95890010	(589) Rents	-	-	-	-	-	-	-	-	-	2,501,463	2,501,463	2,501,463	0
101	95900010	(590) Maintenance Supervision and Engineering	-	-	3,372,383	-	-	-	-	-	-	1,863,857	5,236,241	5,236,243	2
102	95910010	(591) Maintenance of Structures	-	-	-	-	-	-	-	-	-	758,562	758,562	758,562	(0)
103	95920010	(592) Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	19,130,379	19,130,379	19,130,381	2
104	95922010	(592.2) Maintenance of Computer Hardware	471,938	-	-	-	-	-	-	-	-	-	471,938	471,938	(0)
105	95923010	(592.3) Maintenance of Computer Software	6,701,482	-	-	-	-	-	-	-	-	5,826,404	12,527,886	12,527,890	4
106	95924010	(592.4) Maintenance of Communication Equipment	108,413	-	-	-	-	-	-	-	-	-	108,413	108,412	(1)
107	95930010	(593) Maintenance of Overhead Lines	-	-	126,694,681	-	-	-	-	-	-	141,731,265	268,425,945	268,425,947	2
108	95940010	(594) Maintenance of Underground Lines	-	-	-	-	-	-	-	-	-	2,560,753	2,560,753	2,560,756	3
109	95950010	(595) Maintenance of Line Transformers	-	-	-	-	-	-	-	-	-	300,088	300,088	300,088	(0)
110	95960010	(596) Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-	-	-	126,150	126,150	126,150	1
111	95970010	(597) Maintenance of Meters	-	-	-	-	-	-	-	-	-	618,737	618,737	618,737	(0)
112	95980010	(598) Maintenance of Miscellaneous Distribution Plant	-	-	-	-	-	-	-	-	-	(103,007)	(103,007)	(103,007)	(0)
113	99010010	(901) Supervision	621,544	-	-	5,163,380	-	-	28,948	-	446,192	385,336	6,645,400	6,256,721	(388,679)
114	99020010	(902) Meter Reading Expenses	-	-	-	-	-	-	5,464	-	1,616	6,859,744	6,866,824	6,866,824	(0)
115	99030010	(903) Customer Records and Collection Expenses	6,352,660	-	-	24,732,198	-	-	373,986	-	-	762,886	32,221,730	32,221,732	2
116	99041010	(904) Uncollectible Accounts	-	-	-	-	-	-	21,475,242	-	-	-	21,475,242	23,541,561	2,066,319
117	99050010	(905) Miscellaneous Customer Accounts Expenses	-	-	-	2	-	-	-	-	-	-	2	2	(0)
118	99070010	(907) Supervision	-	-	-	17,708,513	-	-	-	-	-	-	17,708,513	17,728,847	20,334
119	99080010	(908) Customer Assistance Expenses	-	234,801	-	13,264,469	-	0	-	-	-	7,651	13,506,920	237,193,411	223,686,491
120	99090010	(909) Informational and Instructional Expenses	-	-	-	-	-	-	-	-	-	-	-	6,228,846	6,228,846
121	99160010	(916) Miscellaneous Sales Expenses	-	-	-	207,042	-	-	-	-	-	-	207,042	207,042	(0)
122	99200010	(920) Administrative and General Salaries	5,959,453	-	-	410,742	1,908,237	-	26,048,528	928,436	1,228,230	-	36,483,627	36,501,997	18,370
123	99210010	(921) Office Supplies and Expenses	19,055,858	-	-	5,681	-	-	913,600	15,320	3,691,285	-	23,681,744	23,188,941	(492,803)
124	99220010	(Less) (922) Administrative Expenses Transferred-Credit	-	-	-	-	(992,283)	-	(18,009,042)	-	-	-	(19,001,325)	(19,001,325)	(1)
125	99230010	(923) Outside Services Employed	3,040,101	-	-	163,179	-	-	7,980,298	1,073,683	2,680,217	125,000	15,062,478	15,378,644	316,166
126	99240010	(924) Property Insurance	-	-	-	-	-	-	2,757,367	-	-	-	2,757,367	1,955,022	(802,345)
127	99250010	(925) Injuries and Damages	-	-	-	-	-	-	16,733,932	-	-	-	16,733,932	16,894,322	160,390
128	99260010	(926) Employee Pensions and Benefits	-	-	-	-	-	-	(1,303,388)	(36,123,571)	-	-	(37,426,959)	(37,407,410)	19,549
129	99280010	(928) Regulatory Commission Expenses	-	-	-	-	-	-	1,134,498	-	-	-	1,134,498	1,134,498	0
130	99302010	(930.2) Miscellaneous General Expenses	-	97	-	1,157,232	-	-	2,148,287	-	-	-	3,305,616	4,533,661	1,228,045
131	99310010	(931) Rents	-	-	-	-	-	-	(68,255)	-	66,008	-	(2,247)	155,157	157,404
132	99350010	(935) Maintenance of General Plant	-	7,154	-	-	-	-	(273,460)	-	4,110,747	-	3,844,440	3,949,139	104,699
133	99351010	(935.1) Maintenance of Computer Hardware	368,320	-	-	-	-	-	-	-	-	-	368,320	368,319	(1)
134	99352010	(935.2) Maintenance of Computer Software	3,180,827	-	-	-	-	-	-	-	-	-	3,180,827	3,180,830	3
135	99353010	(935.3) Maintenance of Communication Equipment	84,610	-	-	-	-	-	-	-	-	-	84,610	84,609	(1)
136		Sub-Total O&M by Witness	$ 67,785,425	$ 112,270,507	$ 135,176,188	$ 62,812,440	$ 915,954	$ 0	$ 65,329,037	$ (34,106,132)	$ 16,690,013	$ 283,018,678	$ 709,892,112	$ 3,198,154,224	$ 2,488,262,112
		Items Included in CECo Other O&M Expense Not Included in the MPSC P-521													
136	94040010	Limited Term Utility -Electric	191,922	-	-	-	-	-	-	-	-	-	191,922	-	(191,922)
137	94160000	Expense Jobbing & CTR	0	-	-	-	-	1,256,024	-	-	-	-	1,256,024	-	(1,256,024)
138	94265010	Other Deductions	-	-	-	-	-	327,080	-	-	-	-	327,080	-	(327,080)
139	94310000	Other Interest Expense	-	3,099	-	-	1,795,480	0	(0)	0	-	-	1,798,579	-	(1,798,579)
140		Allocation Difference	(89,546)	(867,088)	-	-	(434)	-	-	-	-	-	(957,068)	-	957,068
141		Total O&M by Witness (Sum Lines 136-140)	$ 67,887,801	$ 111,406,518	$ 135,176,188	$ 62,812,440	$ 2,711,000	$ 1,583,104	$ 65,329,037	$ (34,106,132)	$ 16,690,013	$ 283,018,678	$ 712,508,648	$ 3,198,154,224	$ 2,485,645,576
		Reconciliation of MPSC P-521 to Exhibit No.: A-3 (HLP-13) and Exhibit No.: A-13 (HLP-37)													
142		Total MPSC P-521 O&M Expense, p. 323, Line 198	Col. (o), Line 141											3,198,154,224	
143		Exclude: Fuel and Purchase Power Expenses												(2,205,894,270)	
144		Exclude: Gain Sale NOX Allow (included in PSCR)												-	
145		Exclude: Electric Vehicle Amortization Expense												(6,362,831)	
146		Exclude: Karn & Campbell Plant Retention & Separation Costs Amortization Expense												(18,235,371)	
147		Exclude: Non-energy related uncollectible expenses and uncollectible reserve activity												(2,066,319)	
148		Include: EICP operational incentive goals												1,795,480	
149		Include: cloud computing amortization included in O&M												191,922	
150		Exclude: O&M Adjustment Related to O&M Expenses Deferred for Recovery related to the U.S. Secretary of Energy's emergency orders under Section 202(c) of the Federal Power Act												(755,362)	
151		Include: Rounding Adjustments												(280,708)	
152		Total adjusted MPSC P-521 O&M expense	Sum of Lines 142 through 151											966,546,765	
153		Total O&M expense per Exhibit No.: A-13 (HLP-37)												966,546,765	
154		Difference												-	
155		Total O&M expense per Exhibit No.: A-13 (HLP-37)												966,546,765	
156		Exclude: EWR Expenses												(192,823,330)	
157		Exclude: REP Expenses												(40,211,258)	
158		Exclude: LIEAF Expenses												(22,606,563)	
159		Exclude: Corporate Giving Salaries Disallowance												(175,008)	
160		Exclude: Excess MDNR Fees												(459,085)	
161		Exclude: Dues/Donations												(661,794)	
162		Include: Jobwork Expenses												1,256,022	
163		Include: Interest expense on security deposits												327,080	
164		Include: Rounding Adjustments												-	
165		Total adjusted other O&M expense	Sum of Lines 155 through 164											711,192,830	
166		Total O&M expense per Exhibit No.: A-13 (HLP-42)												711,192,830	
167		Difference												-	

Schedule: C-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation and Amortization Expenses
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-15)
Schedule: C-6
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Steam production plant - depreciation expense	P-521, p. 336M, Col. (b), Line 2 through P-521, p. 336M, Col. (b), Line	118,559
2	Transmission plant - depreciation expense	P-521, p. 336M, Col. (b), Line 10	-
3	Distribution plant - depreciation expense	P-521, p. 336M, Col. (b), Line 11	392,105
4	General plant - depreciation expense	P-521, p. 336M, Col. (b), Line 13	16,075
5	Common plant - electric - depreciation expense	P-521, p. 336M, Col. (b), Line 14	17,571
6	Total amortization of limited-term electric plant (Acct 404)	P-521, p. 336M, Col. (c), Line 15	1,084
7	Total amortization of other electric plant (Acct 405)	P-521, p. 336M, Col. (d), Line 15	30,992
8	Amortization of utility plant acquisition adjustment	P-521, p.115, Col. (e), Line 9 + P-521, p.117, Col. (c), Line 44	20,377
9	Regulatory debits	P-521, p.115, Col. (e), Line 12	174,707
10	Subtotal	Sum Lines 1 - 9	771,470
11	Less: transmission expense	Line 2 *-1	-
12	Include: Electric Vehicle Amortization Expense	Exhibit No.: A-173 (HLP-51), Lines 8 + 15, column (h)	6,363
13	Include: Karn & Campbell Plant Retention & Separation Costs Amortization Expense	Exhibit No.: A-174 (HLP-52), Lines 5 + 11, column (g)	18,235
14	Exclude: Cloud computing amortization included in O&M	Exhibit No.: A-3 (HLP-14)	(192)
14	Total depreciation and amortization expenses	Sum Line 10 + Line 14	795,876

Schedule C-7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
General Taxes
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-16)
Schedule: C-7
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Real and personal property taxes	P-521, p. 262.1, Col. (i), Line 43	256,497
2	Federal unemployment tax	P-521, p. 262.1, Col. (i), Line 4	108
3	Federal FICA tax	P-521, p. 262.1, Col. (i), Line 6	25,247
4	State income tax	P-521, p. 262.1, Col. (i), Line 18 through 35	478
5	Total payroll taxes	Sum Lines 2 - 4	25,833
6	State fuel tax	P-521, p. 262.1, Col. (i), Lines 36 and 37	-
7	State MPSC assessment	P-521, p. 262.1, Col. (i), Line 38	12,771
8	State franchise tax	P-521, p. 262.1, Col. (i), Line 39	0
9	State sales and use tax absorbed by company	P-521, p. 262.1, Col. (i), Line 40	131
10	Other general taxes	Sum Lines 6 - 9	12,902
11	Total general taxes	Line 1 + Line 5 + Line 10	295,232

Schedule: C-8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Federal Income Taxes
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-17)
Schedule: C-8
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Federal income taxes	P-521, p.115, Col. (g), Line 15	53,660
2	Provision for deferred income taxes	P-521, p.115, Col. (g), Line 17	728,106
3	Provision for deferred income taxes - credit	P-521, p.115, Col. (g), Line 18	(636,097)
4	Investment tax credit adjustment, net	P-521, p.115, Col. (g), Line 19	(3,431)
4	Deferred state income tax	Tax Department	(68,012)
5	Deferred other (local) income tax	Tax Department	(1,010)
6	Total federal income taxes	Sum Lines 1 - 5	73,216

Schedule: C-9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
State Income Taxes
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-18)
Schedule: C-9
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	State income taxes	P-521, p. 262.1, Col. (i), Lines 11 through 17	1,372
2	Deferred state income taxes	Tax Department	68,012
3	Total state income taxes	Line 1 + Line 2	69,384

Schedule: C-10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Other (or Local) Taxes
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-19)
Schedule: C-10
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Other (local) income taxes	P-521, p. 262.1, Col. (i), Line 44	681
2	Deferred other (local) income taxes	Tax Department	1,010
3	Total other (local) income taxes	Line 1 + Line 2	1,690

Schedule: C-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Allowance for Funds Used During Construction
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-20)
Schedule: C-11
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Total allowance for funds used during construction	WP-HLP-11	14,908

Schedule: C-12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Income Tax Effect of Interest
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-21)
Schedule: C-12
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-2 (HLP-3)	15,041,063
2	Weighted cost of debt {a}	Exhibit No.: A-4 (HLP-23)	0.0177
3	Allowable interest expense	Line 1 * Line 2	266,379
4	Actual interest expense {b}	Line {b.8}	314,713
5	Increase/ (decrease) in allowable interest deduction	Line 3 - Line 4	(48,334)
6	Impact on taxable income	Line 5 * -1	48,334
7	Impact on local income taxes	Line 6 * 0.16% Other (Local) Income Tax Rate	77
8	Impact on state income taxes	Line 6 * 5.24% State Income Tax Rate	2,533
9	Impact on federal taxable income	Line 6 - Line 7 - Line 8	45,724
10	Impact on federal income tax	Line 9 * 21.00% Federal Income Tax Rate	9,602
11	Total impact on net operating income	(Line 7 + Line 8 + Line 10) * -1	(12,212)

Notes

{a} Excludes JDITC

{b} Calculation of actual interest expense

{b.1}	Total fixed charges - financial basis	WP-HLP-11	352,520
{b.2}	Lease interest expense	SAP Accounts 95470010, 95550010, 99302010	11,771
{b.3}	Surcharge interest expense	WP-HLP-14	29,767
{b.4}	Subtotal	Line {b.1} - Line {b.2} - Line {b.3}	310,983
{b.5}	AFUDC debt	WP-HLP-11	4,746
{b.6}	Subtotal	Line {b.4} + Line {b.5}	315,729
{b.7}	Preferred stock dividends	WP-HLP-11	1,016
{b.8}	Acutal ratemaking interest expense	Line {b.6} - Line {b.7}	314,713

Schedule: C-13

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Interest Synchronization Adjustment
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-3 (HLP-22)
Schedule: C-13
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-2 (HLP-3)	15,041,063
2	JDITC debt-related portion of the capital structure	Exhibit No.: A-4 (HLP-23)	0.0021
3	Portion of rate base funded by JDITC	Line 1 * Line 2	31,913
4	Cost of JDITC - debt portion	Exhibit No.: A-4 (HLP-23)	0.0413
5	Allowable JDITC interest expense	Line 3 * Line 4	1,319
6	Impact on taxable income	Line 5 * -1	(1,319)
7	Impact on local income taxes	Line 6 * 0.16% Other (Local) Income Tax Rate	(2)
8	Impact on state income taxes	Line 6 * 5.24% State Income Tax Rate	(69)
9	Impact on federal taxable income	Line 6 - Line 7 - Line 8	(1,248)
10	Impact on federal income tax	Line 9 * 21.00% Federal Income Tax Rate	(262)
11	Total impact on net operating income	(Line 7 + Line 8 + Line 10) * -1	333

Schedule: D-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure and Rate of Return Summary
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-4 (HLP-23)
Schedule: D-1
Page: 1 of 1
Witness: HLPatton
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Capital Structure				Weighted Cost			
Line No	Description	Source	Amount	Percent Permanent Capital	Percent of Total Capital	Cost Rate %	Permanent Capital	Total Cost %	Conversion Factor	Pre-Tax Return
1	Long term debt	Exhibit No.: A-2 (HLP-7), Col. (d.1), Line 36	12,081,740	50.45%	42.31%	4.13% {1}	2.09%	1.75%		1.75%
2	Preferred stock	Exhibit No.: A-2 (HLP-7), Col. (d.5), Line 34	37,315	0.16%	0.13%	4.50% {2}	0.01%	0.01%	1.3381	0.01%
3	Common equity	Exhibit No.: A-2 (HLP-7), Col. (d.5), Line 33	11,828,972	49.39%	41.42%	9.90% {3}	4.89%	4.10%	1.3381	5.49%
4	Permanent capital	Sum of Lines 1 through 3	23,948,026							
5	Utility term loan	Exhibit No.: A-2 (HLP-7), Col. (d.2), Line 21	-		0.00%	6.02% {4}		0.00%		0.00%
6	Notes payable	Exhibit No.: A-2 (HLP-7), Col. (d.2), Line 22	59,078		0.21%	6.02% {4}		0.01%		0.01%
7	Advance renewable reg liability	Exhibit No.: A-2 (HLP-7), Col. (d.2), Line 31	44,276		0.16%	6.02% {4}		0.01%		0.01%
8	Short term debt	Sum of Lines 5 through 7	103,353							
9	Deferred federal income tax	Exhibit No.: A-2 (HLP-7), Col. (d.4), Line 36	4,384,537		15.35%	0.00%		0.00%		0.00%
10	Deferred JDITC - long term debt	See Note {5}	60,588		0.21%	4.13%		0.01%		0.01%
11	Deferred JDITC - preferred stock	See Note {5}	187		0.00%	4.50%		0.00%	1.3381	0.00%
12	Deferred JDITC - common equity	See Note {5}	59,320		0.21%	9.90%		0.02%	1.3381	0.03%
13	Total deferred JDITC	Sum of Lines 10 through 12	120,095							
14	Total	Sum of Lines 4, 8, 9, and 13	28,556,012					5.91%		7.30%

Notes

{1} Exhibit No.: A-4 (HLP-24)
{2} Exhibit No.: A-4 (HLP-26)
{3} Exhibit No.: A-4 (HLP-27)
{4} Exhibit No.: A-4 (HLP-25)
{5} The total deferred JDITC balance on line 13 is allocated to lines 10 through 12 based on the percent of permanent capital in column (d)

Schedule: D-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Long-Term Debt (Excluding Securitization)
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-4 (HLP-24)
Schedule: D-2
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Original Issue Date	(c) Stated Maturity Date	(d) Interest Rate %	(e) Amount of Offering	(f) Price to Public %	(g) Underwriting & Financing Expense %	(h) Net Proceeds to the Company %	(i) Cost Based on Net Proceeds %	(j) 13-Mo Avg Amount Outstanding	(k) Annual Cost
	Mortgage Bonds										
1	5.24%	5/30/2023	5/15/2026	5.240%	115,000	100.00%	0.116%	99.88%	5.282%	115,000	6,072
2	3.68% (Private Placement)	10/1/2018	10/1/2027	3.680%	100,000	100.00%	0.159%	99.84%	3.701%	100,000	3,698
3	3.39%	12/17/2012	12/15/2027	3.390%	35,500	100.00%	0.540%	99.46%	3.436%	35,500	1,216
4	3.80%	11/13/2018	11/15/2028	3.800%	300,000	99.75%	0.752%	99.00%	3.922%	300,000	11,698
5	4.65%	1/10/2023	3/1/2028	4.650%	425,000	99.81%	0.833%	98.98%	4.875%	425,000	20,606
6	5.07%	5/30/2023	5/15/2029	5.070%	50,000	100.00%	0.232%	99.77%	5.115%	50,000	2,555
7	4.90%	8/4/2023	2/15/2029	4.900%	500,000	99.95%	0.806%	99.14%	5.079%	500,000	25,272
8	4.60%	1/9/2024	5/30/2029	4.600%	600,000	99.77%	0.704%	99.06%	4.798%	600,000	28,796
9	0.047	8/5/2024	1/15/2030	4.700%	700,000	99.78%	0.712%	99.06%	4.898%	700,000	34,215
10	0.045	5/2/2025	1/15/2031	4.500%	500,000	99.97%	0.680%	99.29%	4.642%	307,692	15,389
11	3.60%	8/11/2022	8/15/2032	3.600%	350,000	99.93%	0.850%	99.08%	3.711%	350,000	12,898
12	3.18% (Private Placement)	9/28/2017	9/28/2032	3.180%	40,000	100.00%	0.333%	99.67%	3.208%	40,000	1,281
13	3.18% (Private Placement)	11/15/2017	11/15/2032	3.180%	60,000	100.00%	0.332%	99.67%	3.208%	60,000	1,921
14	0.0517	5/30/2023	5/15/2032	5.170%	95,000	100.00%	0.340%	99.66%	5.218%	95,000	4,947
15	0.04625	2/23/2023	5/15/2033	4.625%	700,000	99.45%	0.847%	98.60%	4.799%	700,000	33,331
16	5.80%	8/11/2005	9/15/2035	5.800%	175,000	99.81%	1.046%	98.76%	5.888%	175,000	10,222
17	0.0505	5/2/2025	5/15/2035	5.050%	625,000	99.63%	0.781%	98.85%	5.198%	384,615	21,458
18	3.52% (Private Placement)	9/28/2017	9/28/2037	3.520%	125,000	100.00%	0.444%	99.56%	3.551%	125,000	4,428
19	3.52% (Private Placement)	11/15/2017	11/15/2037	3.520%	210,000	100.00%	0.443%	99.56%	3.551%	210,000	7,438
20	5.38%	5/30/2023	5/15/2037	5.380%	140,000	100.00%	0.524%	99.48%	5.434%	140,000	7,585
21	4.01% (Private Placement)	10/1/2018	10/1/2038	4.010%	215,000	100.00%	0.349%	99.65%	4.036%	215,000	8,659
22	6.17%	9/1/2010	9/1/2040	6.170%	50,000	100.00%	0.984%	99.02%	6.243%	50,000	3,101
23	4.97%	10/15/2010	10/15/2040	4.970%	50,000	100.00%	0.539%	99.46%	5.005%	50,000	2,494
24	4.31%	12/17/2012	12/15/2042	4.310%	263,000	100.00%	0.528%	99.47%	4.342%	263,000	11,381
25	3.95%	5/17/2013	5/15/2043	3.950%	425,000	99.84%	1.034%	98.81%	4.019%	425,000	15,931
26	4.10%	11/6/2015	11/15/2045	4.100%	250,000	99.91%	1.054%	98.86%	4.167%	250,000	10,345
27	3.25%	8/10/2016	8/15/2046	3.250%	450,000	99.22%	1.058%	98.16%	3.347%	450,000	11,582
28	3.95%	2/22/2017	7/15/2047	3.950%	350,000	99.58%	1.066%	98.52%	4.035%	350,000	13,995
29	4.05%	5/14/2018	5/15/2048	4.050%	550,000	98.97%	1.076%	97.89%	4.174%	550,000	20,231
30	4.35%	11/13/2018	4/15/2049	4.350%	550,000	99.62%	1.054%	98.56%	4.436%	550,000	24,184
31	3.75%	5/28/2019	2/15/2050	3.750%	300,000	98.83%	1.086%	97.75%	3.876%	300,000	10,037
32	0.031	9/3/2019	8/15/2050	3.100%	550,000	99.29%	0.971%	98.32%	3.186%	550,000	12,709
33	0.035	3/26/2020	8/1/2051	3.500%	575,000	100.00%	1.094%	98.91%	3.558%	575,000	17,235
34	0.0265	8/2/2021	8/15/2052	2.650%	300,000	99.92%	1.065%	98.85%	2.705%	300,000	8,061
35	4.20%	8/11/2022	9/1/2052	4.200%	450,000	99.93%	1.075%	98.85%	4.268%	450,000	18,658
36	3.86% (Private Placement)	9/28/2017	9/28/2052	3.860%	20,000	100.00%	0.777%	99.22%	3.901%	20,000	776
37	3.86% (Private Placement)	11/15/2017	11/15/2052	3.860%	30,000	100.00%	0.775%	99.22%	3.901%	30,000	1,165
38	4.28% (Private Placement)	10/1/2018	10/1/2057	4.280%	185,000	100.00%	0.676%	99.32%	4.316%	185,000	7,950
39	0.025	5/13/2020	5/1/2060	2.500%	525,000	100.00%	1.047%	98.95%	2.542%	525,000	13,374
40	0.0435	8/18/2014	8/31/2064	4.350%	250,000	99.14%	0.999%	98.14%	4.443%	250,000	10,968
41	Floating Rate FMB {a}	9/19/2019	9/15/2069	2.993%	75,649	100.00%	1.993%	98.01%	3.071%	75,649	3,241
42	Floating Rate FMB {b}	5/20/2020	5/20/2070	2.684%	134,349	100.00%	1.291%	98.71%	2.731%	134,349	5,798
43	Floating Rate FMB {c}	10/7/2020	10/7/2070	2.048%	126,497	100.00%	1.250%	98.75%	2.089%	126,497	5,380
44	Total First Mortgage Bonds									12,087,303	492,282
	Other Long-Term Debt										
45	PCRB - MSF LORB - 2019	Oct-01-2019	Oct-01-2049	1.800%	75,000	100.00%	1.485%	98.52%	1.865%	75,000	2,533
46	PCRB - MSF LORB - 2021	Oct-07-2021	Apr-01-2035	0.875%	35,000	100.00%	1.500%	98.50%	0.994%	35,000	342
47	Total other long term debt									110,000	2,875
	Cost of Long-Term Debt Calculation										
48	Total Annual Cost										495,157
49	Amortization of Losses on Reacquired Debt with Refunding (including Call Premiums)										4,354
50	Total Long-Term Debt Annual Cost Balance										499,511
51	Total Long-Term Debt										12,197,303
52	Unamortized Debt Discount, Premium, and Expense										(31,768)
53	Unamortized Debt Costs										(83,795)
54	Total Long-Term Debt Balance										12,081,740
55	Average Cost of Long-Term Debt										4.13%

Notes

{a} Interest rate for $76M floating rate FMBs due 2069 is 3-mo SOFR minus 3.839 basis points, resetting quarterly on 3/15, 6/15, 9/15, and 12/15
{b} Interest rate for $134M floating rate FMBs due 2070 is 3-mo SOFR minus 3.839 basis points, resetting quarterly on 2/20, 5/20, 8/20, and 11/20
{c} Interest rate for $126M floating rate FMBs due 2070 is 3-mo SOFR minus 3.839 basis points, resetting quarterly on 1/7, 4/7, 7/7, and 10/7

Schedule: D-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Short-Term Debt
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-4 (HLP-25)
Schedule: D-3
Page: 1 of 1
Witness: HLPatton
Date: June 2026

(a)	(b)	(c)	(d)	(e)

Line No	Description	Source	Amount	Annual Cost	Average Cost of Short-Term Debt
1	Utility term loan	Exhibit No.: A-2 (HLP-7), Col. (d.2), Line 21	-		
2	Notes payable	Exhibit No.: A-2 (HLP-7), Col. (d.2), Line 22	59,078		
3	Advanced renewable reg liability	Exhibit No.: A-2 (HLP-7), Col. (d.2), Line 31	44,276		
4	Total	Sum of Lines 1 through 3	103,353	6,219	6.02%

Notes

{1} SAP Accounts 8000000, 8020000, 8030000, 8200000, 8220000, 8265001, and 8300000

Schedule: D-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Preferred Stock
For the Historical Year Ended December 31, 2025
($000)

Case No.: U-22070
Exhibit No.: A-4 (HLP-26)
Schedule: D-4
Page: 1 of 1
Witness: HLPatton
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No	**Description**	**Annual Dividend**	**Par Value**	**Discount / (Premium)**	**Finance Expense**	**Net Proceeds Received**	**Number of Shares Outstanding**	**Total Value of Outstanding Proceeds {1}**	**Cost Rate %**	**Annual Dollar Amount**
1	Preferred stock	4.50	100	-	-	100	373,148	37,315	4.50%	1,679

Notes

{1} Exhibit No.: A-2 (HLP-7), Col. (d.5), Line 34

Schedule: D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Historical Year Ended December 31, 2025

Case No.: U-22070
Exhibit No.: A-4 (HLP-27)
Schedule: D-5

Witness: HLPatton
Date: June 2026

Line No	(a) Description
1	The Company's authorized cost of common equity is 9.90%. This rate was authorized by the Michigan Public Service Commission on March 21, 2025 in Electric Rate Case U-21585.

Schedule: A-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Deficiency (Sufficiency)
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-11 (HLP-28)
Schedule: A-1
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Total Amount
1	Rate base	Exhibit No.: A-12 (HLP-31)	17,022,569
2	Adjusted net operating income	Exhibit No.: A-13 (HLP-36)	834,710
3	Overall rate of return	Line 2 / Line 1	4.90%
4	Required rate of return	Exhibit No.: A-14 (MRB-1), Schedule D-1	6.59%
5	Income requirement	Line 1 * Line 4	1,122,345
6	Income deficiency (sufficiency)	Line 5 - Line 2	287,635
7	Revenue conversion factor	Exhibit No.: A-13 (HLP-38)	1.3381
8	Revenue Deficiency / (Sufficiency)	Line 6 * Line 7	384,878
9	Return On - Campbell Regulatory Asset	Exhibit No.: A-179 (HLP-57)	70,954
10	Revenue Deficiency / (Sufficiency) - Total	Line 8 + Line 9	455,832

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
For the Projected 12-Month Period Ending April 30, 2028
ELECTRIC RESULTS ONLY
($000)

Case No.: U-22070
Exhibit No.: A-11 (HLP-29)
Schedule: A-2
Page: 1 of 3
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) No Rate Relief	(c) Full Rate Relief
1	Operating revenues	5,691,456	6,147,288
2	Operating expenses	4,759,112	4,759,112
3	Pre-tax operating income	932,344	1,388,176
4	Income taxes	114,674	283,297
5	Net operating income	817,670	1,104,879
6	Tax effect of pro forma interest on NOI	Included in Line 4	Included in Line 4
7	AFUDC	17,040	17,040
8	Interest charges, net of tax benefit	(339,038)	(339,038)
9	Preferred stock dividends	(765)	(765)
10	Net income available to common stockholders and JDITC	494,907	782,116
11	Return assignable to JDITC	(3,071)	(3,071)
12	Net income available to common stockholders	491,836	779,045
13	Average common equity	7,600,436	7,600,436
14	Earned rate of return on common equity	6.47%	10.25%
15	Authorized rate of return on common equity {1}	10.25%	10.25%

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
For the Projected 12-Month Period Ending April 30, 2028
ELECTRIC RESULTS ONLY
($000)

Case No.: U-22070
Exhibit No.: A-11 (HLP-29)
Schedule: A-2
Page: 2 of 3
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) No Rate Relief	(c) Full Rate Relief
	EBIT Interest Coverage Ratio		
16	Pre-tax operating income	932,344	1,388,176
17	AFUDC	17,040	17,040
18	Total EBIT	949,384	1,405,216
19	Interest charges, net of tax benefit	339,038	339,038
20	EBIT interest coverage ratio	2.80	4.14
	EBITDA Interest Coverage Ratio		
21	Total EBIT	949,384	1,405,216
22	Depreciation and amortization	854,516	854,516
23	EBITDA	1,803,899	2,259,731
24	Interest charges, net of tax benefit	339,038	339,038
25	EBITDA interest coverage ratio	5.32	6.67
	FFO Interest Coverage Ratio {2}		
26	Net operating income	817,670	1,104,879
27	Depreciation and amortization	854,516	854,516
28	Deferred income taxes	88,578	88,578
29	AFUDC	17,040	17,040
30	Other major recurring non-cash items	-	-
31	Interest paid	314,813	314,813
	Less:		
32	Operating lease adjustment to depreciation	-	-
33	Subtotal	2,092,616	2,379,825
34	Interest charges, net of tax benefit	339,038	339,038
35	FFO interest coverage ratio	6.17	7.02
	Overall Fixed Charge Coverage Ratio		
36	Net income available to common stockholders	491,836	779,045
37	Interest charges, net of tax benefit	339,038	339,038
38	Subtotal numerator	830,873	1,118,082
39	Interest charges, net of tax benefit	339,038	339,038
40	Preferred stock dividends	765	765
41	Subtotal denominator	339,803	339,803
42	Overall fixed charge coverage ratio	2.45	3.29

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
For the Projected 12-Month Period Ending April 30, 2028
ELECTRIC RESULTS ONLY
($000)

Case No.: U-22070
Exhibit No.: A-11 (HLP-29)
Schedule: A-2
Page: 3 of 3
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) No Rate Relief	(c) Full Rate Relief
	Cash Flow Coverage of Dividend Ratio		
43	Net income available to common stockholders	491,836	779,045
44	Depreciation and amortization	854,516	854,516
45	Deferred taxes	88,578	88,578
46	Subtotal	1,434,929	1,722,138
47	Common dividends {3}	393,469	623,236
48	Cash flow coverage of dividends ratio	3.65	2.76
	Common Dividend Payout Ratio		
49	Common dividends {3}	393,469	623,236
50	Net income available to common stockholders	491,836	779,045
51	Common dividend payout ratio	80%	80%
	Permanent Capitalization		
52	Long term debt, excluding securitization	15,515	15,515
53	Preferred stock	37	37
54	Common equity	16,681	16,681
55	Permanent capitalization	32,233	32,233
56	Long term debt, excluding securitization	48.13%	48.13%
57	Preferred stock	0.12%	0.12%
58	Common equity	51.75%	51.75%
59	Permanent capitalization	100.00%	100.00%

Notes

{1} The company is requesting an ROE of 10.25% in this case
{2} FFO = Funds Flow from Operations
{3} Consumers Energy pays dividends to the parent as a total company. This number represents the company's 80% dividend policy applied to Net Income Available to Common Stockholders

Schedule: A-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of the Historical and Projected Revenue Requirement
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-11 (HLP-30)
Schedule: A-3
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source: Historical Year	(c) Source: Projected Test Year	(d) Amounts: Historical Year	(e) Amounts: Change	(f) Amounts: Test Year
1	Net utility plant	Exhibit No.: A-2 (HLP-3)	Exhibit No.: A-12 (HLP-31)	11,732,269	2,997,537	14,729,806
2	Working capital	Exhibit No.: A-2 (HLP-3)	Exhibit No.: A-12 (HLP-31)	3,308,793	(1,016,031)	2,292,763
3	Rate base	Line 1 + Line 2	Line 1 + Line 2	15,041,063	1,981,506	17,022,569
4	Rate of return	Exhibit No.: A-4 (HLP-23)	Exhibit No.: A-14 (MRB-1), Schedule D-1	5.91%		6.59%
5	Income requirement	Line 3 * Line 4	Line 3 * Line 4	888,507	233,838	1,122,345
6	Adjusted net operating income	Exhibit No.: A-3 (HLP-9)	Exhibit No.: A-13 (HLP-36)	893,051	(58,341)	834,710
7	Income deficiency (sufficiency)	Line 5 - Line 6	Line 5 - Line 6	(4,544)	292,179	287,635
8	Revenue conversion factor	Exhibit No.: A-3 (HLP-10)	Exhibit No.: A-13 (HLP-38)	1.3381		1.3381
9	Revenue deficiency (sufficiency)	Line 7 * Line 8	Line 7 * Line 8	(6,080)	390,958	384,878
10	Return on Campbell Reg Asset	{1}	Exhibit No.: A-179 (HLP-57)	-		70,954
11	Total Revenue deficiency (sufficiency)			(6,080)		455,832

Notes
{1} The return on the Campbell Regulatory Asset is included in line 9 for the historical year.

Schedule: B-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Rate Base
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-12 (HLP-31)
Schedule: B-1
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Total utility plant	Exhibit No.: A-12 (HLP-32)	21,477,539
2	Depreciation reserve	Exhibit No.: A-12 (HLP-33)	6,675,063
3	Net utility plant	Line 1 - Line 2	14,802,477
4	Customer advances for construction	Exhibit No.: A-2 (HLP-7)	(72,670)
5	Utility plant rate base	Sum Lines 3 - 4	14,729,806
6	Working capital	Exhibit No.: A-12 (HLP-34)	2,292,763
7	Total rate base	Line 5 + Line 6	17,022,569

Schedule: B-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Utility Plant
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-12 (HLP-32)
Schedule: B-2
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) FERC Account Number	(c) Source	(d) Amount
1	Distribution		WP-HLP-22, Col. (c), Line 1	15,372,037
2	Production (Hydro)		WP-HLP-22, Col. (c), Line 2	248,607
3	Production (Hydro Ludington)		WP-HLP-22, Col. (c), Line 3	621,208
4	Production (Steam)		WP-HLP-22, Col. (c), Line 4	456,382
5	Production (Battery)		WP-HLP-22, Col. (c), Line 5	123,390
6	Production (Other)		WP-HLP-22, Col. (c), Line 6	1,810,274
7	Intangibles		WP-HLP-22, Col. (c), Line 7	519,750
8	E-GP Structures		WP-HLP-22, Col. (c), Line 8	199,702
9	E-GP Computers		WP-HLP-22, Col. (c), Line 9	10,236
10	E-GP Transportation		WP-HLP-22, Col. (c), Line 10	196,042
11	E-GP Other		WP-HLP-22, Col. (c), Line 11	83,902
12	C-GP Structures		WP-HLP-22, Col. (c), Line 12	175,674
13	C-GP Computers		WP-HLP-22, Col. (c), Line 13	59,589
14	C-GP Transportation		WP-HLP-22, Col. (c), Line 14	85,813
15	C-GP Other		WP-HLP-22, Col. (c), Line 15	114,434
16	Production Acq Adjustment		WP-HLP-22, Col. (c), Line 16	584,035
17	Total plant-in-service	101	Sum of Lines 1 through 16	20,661,075
18	Plant purchased or sold	102	WP-HLP-10	-
19	Experimental plant unclassified	103	WP-HLP-10	-
20	Plant leased to others	104	WP-HLP-10	-
21	Plant held of future use	105	WP-HLP-10	11,781
22	Completed construction not classified	106	WP-HLP-10	-
23	Construction work in progress	107	WP-HLP-23 Col. (c), Line 19	804,684
24	Total utility plant		Sum Lines 17 through 23	21,477,539

Schedule: B-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation Reserve and Other Deductions
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-12 (HLP-33)
Schedule: B-3
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Distribution	WP-HLP-24, Col. (c), Line 1	4,149,736
2	Production (Hydro)	WP-HLP-24, Col. (c), Line 2	447,278
3	Production (Hydro Ludington)	WP-HLP-24, Col. (c), Line 3	268,789
4	Production (Steam)	WP-HLP-24, Col. (c), Line 4	301,622
5	Production (Battery)	WP-HLP-24, Col. (c), Line 5	15,827
6	Production (Other)	WP-HLP-24, Col. (c), Line 6	512,274
7	Intangibles	WP-HLP-24, Col. (c), Line 7	445,082
8	E-GP Structures	WP-HLP-24, Col. (c), Line 8	49,891
9	E-GP Computers	WP-HLP-24, Col. (c), Line 9	5,696
10	E-GP Transportation	WP-HLP-24, Col. (c), Line 10	65,846
11	E-GP Other	WP-HLP-24, Col. (c), Line 11	33,614
12	C-GP Structures	WP-HLP-24, Col. (c), Line 12	76,689
13	C-GP Computers	WP-HLP-24, Col. (c), Line 13	27,043
14	C-GP Transportation	WP-HLP-24, Col. (c), Line 14	59,558
15	C-GP Other	WP-HLP-24, Col. (c), Line 15	44,585
16	Production Acq Adjustment	WP-HLP-24, Col. (c), Line 16	171,530
17	Total depreciation reserve and other deductions	Sum Lines 1 - 16	6,675,063

Schedule: B-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Working Capital
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-12 (HLP-34)
Schedule: B-4
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Historical Year Working Capital	(c) Pension Adjustment	(d) OPEB Adjustment	(e) Pension/OPEB Volatility Mechanism	(f) Accrued Tax Adjustment	(g) Prepaid Cloud Computing Adjustment	(h) PowerMIDrive and PowerMIFleet Adjustment	(i) Karn & Campbell Retention	(j) Campbell NBV, Ash Disposal, Decommissioning	(k) S/4 HANA Implementation Deferral Adjustment	(l) Other	(m) Total Adjustments	(n) Test Year Working Capital
1	Cash, cash equivalents, and restricted cash	142,570	-	-	-	-	-	-	-	-	-	(86,017)	(86,017)	56,553
2	Accounts and notes receivable	345,983	-	-	-	-	-	-	-	-	-	-	-	345,983
3	Fuel stock	25,098	-	-	-	-	-	-	-	-	-	-	-	25,098
4	Materials and supplies	251,263	-	-	-	-	-	-	-	-	-	-	-	251,263
5	Allowances	14	-	-	-	-	-	-	-	-	-	-	-	14
6	Prepayments	1,066,624	-	-	-	-	4,923	-	-	-	-	-	4,923	1,071,547
7	Accrued revenue	347,636	-	-	-	-	-	-	-	-	-	-	-	347,636
8	Deferred taxes	283,834	-	-	-	-	-	-	-	-	-	-	-	283,834
9	Deferred debits	2,104,763	130,606	133,948	(15,640)	-	-	(11,263)	(20,020)	(1,260,110)	33,612	-	(1,008,867)	1,095,896
10	Total assets	4,567,785	130,606	133,948	(15,640)	-	4,923	(11,263)	(20,020)	(1,260,110)	33,612	(86,017)	(1,089,962)	3,477,823
11	Accounts payable	612,195	-	-	-	-	-	-	-	-	-	-	-	612,195
12	Customer deposits	26,644	-	-	-	-	-	-	-	-	-	-	-	26,644
13	Accrued interest	73,846	-	-	-	-	-	-	-	-	-	-	-	73,846
14	Dividends payable	29,263	-	-	-	-	-	-	-	-	-	-	-	29,263
15	Accrued taxes	347,287	-	-	-	(78,244)	-	-	-	-	-	-	(78,244)	269,042
16	Other liabilities	80,233	-	-	-	-	-	-	-	-	-	-	-	80,233
17	Deferred credits	89,525	-	-	5,814	-	-	-	-	-	-	(1,500)	4,314	93,839
18	Total liabilities	1,258,992	-	-	5,814	(78,244)	-	-	-	-	-	(1,500)	(73,931)	1,185,061
19	Total working capital	3,308,793	130,606	133,948	(21,454)	78,244	4,923	(11,263)	(20,020)	(1,260,110)	33,612	(84,517)	(1,016,031)	2,292,763

Notes

Col. (b): Exhibit No.: A-2 (HLP-6)
Col. (c): WP-HLP-27
Col. (d): WP-HLP-28
Col. (e): WP-HLP-29
Col. (f): WP-HLP-30
Col. (g): WP-HLP-31
Col. (h): WP-HLP-32
Col. (i): WP-HLP-33
Col. (j): WP-HLP-34
Col. (k): WP-HLP-35
Col. (l), Line 1: Testimony of Company Witness M. Bleckman
Col. (l), Line 17: A-185 (HLP-63)

Schedule: B-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Expenditures Summary
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-12 (HLP-35)
Schedule: B-5
Page 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Historical 12 Months Ended 12/31/2025	(d) Projected 12 Months Ending 12/31/2026	(e) Projected 4 Months Ending 4/30/2027	(f) Projected 16 Months Ending 4/30/2027	(g) Projected 12 Months Ending 4/30/2028	(h) Approved Capital Expenditures in U-21870 12 Months Ending 4/30/2027	(i) Projected Capital Expenditures in U-21870 12 Months Ending 4/30/2027
1	Electric Distribution	Exhibit No.: A-12 (EMD-1), Sch 5.6	1,279,640	1,233,360	549,615	1,782,975	1,460,571	1,275,209	1,529,914
2	Streetlighting	Exhibit No.: A-12 (DAS-1), Sch 5.10	23,303	20,977	7,167	28,144	21,659	16,545	16,545
3	Generation	Exhibit No.: A-12 (MEW-3), Sch 5.2	220,702	205,557	57,850	263,407	163,084	181,183	188,638
4	Information Technology	Exhibit No.: A-12 (SHB-4), Sch 5.5	32,401	75,463	27,010	102,473	47,471	66,223	66,983
5	Security	Exhibit No.: A-12 (SHB-4), Sch 5.5	4,635	6,928	4,386	11,315	11,229	10,736	10,736
6	Electric Vehicles	Exhibit No.: A-12 (AMG-10), Sch 5.9	1,990	593	-	593	-	171	171
7	Operations Support	Exhibit No.: A-12 (QAG-1), Sch 5.4	38,991	50,708	13,017	63,725	22,495	19,246	28,041
8	Fleet Services	Exhibit No.: A-12 (JJJ-1), Sch 5.1	23,915	65,711	10,557	76,268	26,633	39,172	67,947
9	Corporate	Exhibit No.: A-12 (MJF-6), Sch 5.3	788	810	277	1,087	837	1,064	1,064
10	Customer Experience & Growth	Exhibit No.: A-12 (AMG-3), Sch 5.8	126	845	170	1,015	510	1,870	1,870
11	Demand Response	Exhibit No.: A-12 (AMG-1), Sch 5.7	(497)	417	60	477	180	1,555	1,555
12	Total capital expenditures		1,625,994	1,661,370	670,109	2,331,479	1,754,669	1,612,974	1,913,464

Notes

Schedule: C-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-36)
Schedule: C-1
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Sales revenues	Exhibit No.: A-13 (HLP-39)	5,386,010
2	Wholesale revenues	Exhibit No.: A-13 (HLP-39)	-
3	Other electric revenues	Exhibit No.: A-13 (HLP-39)	305,445
4	Total operating revenues	Sum Lines 1 - 3	5,691,456
5	Power supply costs	Exhibit No.: A-13 (HLP-40)	2,765,982
6	Operations and maintenance	Exhibit No.: A-13 (HLP-41)	796,074
7	Depreciation and amortization	Exhibit No.: A-13 (HLP-43)	854,516
8	Property taxes	Exhibit No.: A-13 (HLP-44)	301,800
9	General taxes	Exhibit No.: A-13 (HLP-44)	40,741
10	Other (local) taxes	Exhibit No.: A-13 (HLP-47)	1,182
11	State income taxes	Exhibit No.: A-13 (HLP-46)	36,041
12	Federal income taxes	Exhibit No.: A-13 (HLP-45)	77,450
13	Total operating expenses	Sum Lines 5 - 12	4,873,786
14	Net operating income	Line 4 - Line 13	817,670
15	AFUDC	Exhibit No.: A-13 (HLP-48)	17,040
16	Net operating income, including AFUDC	Line 14 + Line 15	834,710
	Net Operating Income Adjustments		
17	Income tax effect of interest {a}		Included in Lines 10, 11, and 12
18	Interest synchronization adjustment {a}		Included in Lines 10, 11, and 12
19	Total adjusted net operating income	Line 16	834,710

Notes

{a} Income tax effect of interest and the interest synchronization adjustment are included in the calculation of local, state, and federal income tax. The separate calculations can be found on Exhibit No.: A-13 (HLP-49) and Exhibit No.: A-13 (HLP-50)

Schedule: C-1.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of Adjusted Net Operating Income
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-37)
Schedule: C-1.1
Page 1 of 1
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Source	(c) Sales	(d) Whlsale	(e) Other Revenue	(f) Fuel P&I	(g) Other O&M	(h) Deprec.	(i) Property Tax	(j) Other Taxes	(k) CIT	(l) MCIT	(m) FIT	(n) NOI	(o) AFUDC	(p) Adjusted NOI
1	Net operating income - historical year		5,113,363	140,455	268,285	2,205,894	966,547	795,876	256,497	38,736	1,690	69,384	73,216	1,114,263	14,908	1,129,171
	Historical Year Adjustments															
2	Weather normalization	Exhibit No.: A-15 (EMB-3), Schedule E-2	(70,060)	-	-	-	-	-	-	-	(112)	(3,671)	(13,918)	(52,358)	-	(52,358)
3	Purchased power administration fee revenue	WP-HLP-13	-	-	(808)	-	-	-	-	-	(1)	(42)	(160)	(604)	-	(604)
4	Surcharge Revenues and Other Adjustments	WP-HLP-14	(608,873)	-	-	-	(255,641)	(172,079)	(13,769)	65,566	(362)	(11,853)	(44,939)	(175,796)	-	(175,796)
5	Jobwork revenues	WP-HLP-20	-	-	1,859	-	-	-	-	-	3	97	369	1,389	-	1,389
6	Interest income on cash operating accounts	WP-HLP-15	-	-	4,472	-	-	-	-	-	7	234	888	3,342	-	3,342
7	Excess MDNR fees	WP-HLP-12	-	-	-	-	(459)	-	-	-	1	24	91	343	-	343
8	Compensation expenses	WP-HLP-16	-	-	-	-	(175)	-	-	-	0	9	35	131	-	131
9	Advertising expenses	WP-HLP-17	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Dues & donations expenses	WP-HLP-18	-	-	-	-	(662)	-	-	-	1	35	131	495	-	495
11	Jobwork expenses	WP-HLP-20	-	-	-	-	1,256	-	-	-	(2)	(66)	(250)	(939)	-	(939)
12	Interest expense on security deposits	WP-HLP-19	-	-	-	-	327	-	-	-	(1)	(17)	(65)	(244)	-	(244)
13	Income Tax Effect of Interest	Exhibit No.: A-3 (HLP-21)	-	-	-	-	-	-	-	-	77	2,533	9,602	(12,212)	-	(12,212)
14	Interest Synchronization Adjustment	Exhibit No.: A-3 (HLP-22)	-	-	-	-	-	-	-	-	(2)	(69)	(262)	333	-	333
15	Adjusted net operating income - historical year		4,434,430	140,455	273,808	2,205,894	711,193	623,797	242,727	104,302	1,300	56,598	24,739	878,143	14,908	893,051
	Test Year Adjustments															
16	Sales revenues		951,581	-	-	-	-	-	-	-	1,523	49,863	189,041	711,154	-	711,154
17	Sales for Resale		-	(140,455)	-	-	-	-	-	-	(225)	(7,360)	(27,903)	(104,967)	-	(104,967)
18	Other electric revenues		-	-	31,637	-	-	-	-	-	51	1,658	6,285	23,644	-	23,644
19	Fuel and P&I expenses		-	-	-	560,088	-	-	-	-	(896)	(29,349)	(111,267)	(418,576)	-	(418,576)
20	Other operation and maintenance		-	-	-	-	84,881	-	-	-	(136)	(4,448)	(16,863)	(63,435)	-	(63,435)
21	Depreciation and amortization		-	-	-	-	-	230,719	-	-	(369)	(12,090)	(45,835)	(172,425)	-	(172,425)
22	Property taxes		-	-	-	-	-	-	59,073	-	(95)	(3,095)	(11,735)	(44,147)	-	(44,147)
23	Other general taxes		-	-	-	-	-	-	-	(63,561)	102	3,331	12,627	47,502	-	47,502
24	Other (local) income taxes		-	-	-	-	-	-	-	-	(72)	-	15	57	-	57
25	State income taxes		-	-	-	-	-	-	-	-	-	(19,067)	4,004	15,063	-	15,063
26	Federal income taxes		-	-	-	-	-	-	-	-	-	-	54,341	(54,341)	-	(54,341)
27	AFUDC		-	-	-	-	-	-	-	-	-	-	-	-	2,132	2,132
28	Adjusted net operating income - projected test year		5,386,010	-	305,445	2,765,982	796,074	854,516	301,800	40,741	1,182	36,041	77,450	817,670	17,040	834,710

Notes

Line 1, Col. (c) - Col. (p) Source: Exhibit No.: A-3 (HLP-9)

Schedule: C-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of the Revenue Conversion Factor
For the Projected 12-Month Period Ending April 30, 2028

Case No.: U-22070
Exhibit No.: A-13 (HLP-38)
Schedule: C-2
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Income base - before taxes		100.0000
2	State income tax	Line 1 * 5.24% State Income Tax Rate	5.2400
3	Other (local) income tax	Line 1 * 0.16% Other {Local) Income Tax Rate	0.1600
4	Federal income tax base	Line 1 - Line 2 - Line 3	94.6000
5	Federal income tax	Line 4 * 21.00% Federal Income Tax Rate	19.8660
6	Income base - after taxes	Line 4 - Line 5	74.7340
7	Revenue conversion factor	Line 1 / Line 6	1.3381

Schedule: C-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operating Revenues
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-39)
Schedule: C-3
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Sales revenues	Exhibit No.: A-15 (EMB-3), Schedule E-2	5,386,010
2	Wholesale revenues	N/A	-
3	Other electric revenue	Exhibit No.: A-15 (EMB-3), Schedule E-2	305,445
4	Total operating revenues	Sum Lines 1 - 3	5,691,456

Schedule: C-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Fuel and Purchased Power
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-40)
Schedule: C-4
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Total fuel and purchased power	Exhibit No.: A-58 (EMB-6)	2,765,982

Schedule: C-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operation and Maintenance Expenses
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-41)
Schedule: C-5
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Source	(c) Historical Year	(d) Change	(e) Projected Test Year
1	Electric Division - Electric & Common	Exhibit No.: A-89 (EMD-5)	283,019	38,637	321,655
2	Forestry	Exhibit No.: A-191 (SES-6)	135,176	32,573	167,749
3	Generation	Exhibit No.: A-197 (MEW-4)	111,407	(8,924)	102,482
4	Operations Support	Exhibit No.: A-136 (QAG-2)	16,690	(524)	16,166
5	Information Technology Operations	Exhibit No.: A-17 (SHB-1)	49,197	11,123	60,320
6	Information Technology Investments	Exhibit No.: A-19 (SHB-3)	7,698	2,356	10,055
7	Information Technology - Security Operations	Exhibit No.: A-17 (SHB-1)	10,179	3,242	13,421
8	Information Technology - Security Investments	Exhibit No.: A-19 (SHB-3)	814	733	1,547
9	Customer Interactions	Exhibit No.: A-110 (AMG-2)	22,524	5,613	28,137
10	Billing & Payment	Exhibit No.: A-110 (AMG-2)	10,882	1,757	12,640
11	Demand Response	Exhibit No.: A-111 (AMG-4)	29,406	4,222	33,628
12	Pension Plans A/B	Exhibit No.: A-125 (KKG-1)	(47,918)	(13,934)	(61,852)
13	Defined Company Contribution Plan	Exhibit No.: A-125 (KKG-1)	16,512	1,070	17,582
14	401(k) Employees' Savings Plan	Exhibit No.: A-125 (KKG-1)	13,321	1,379	14,700
15	Active Health Care/Life Insurance/LTD	Exhibit No.: A-125 (KKG-1)	32,073	4,485	36,558
16	Retiree Health Care and Life Insurance	Exhibit No.: A-125 (KKG-1)	(49,261)	(3,500)	(52,761)
17	Other Benefits	Exhibit No.: A-125 (KKG-1)	2,822	230	3,052
18	Pension/OPEB Volatility Mechanism Amortization	Exhibit No.: A-125 (KKG-1)	(1,655)	(875)	(2,530)
19	Corporate Services	Exhibit No.: A-104 (MJF-1)	24,280	1,516	25,796
20	Insurance Expense	Exhibit No.: A-104 (MJF-1)	14,143	1,123	15,266
21	Uncollectible Expense	Exhibit No.: A-104 (MJF-1)	21,475	86	21,561
22	Injuries & Damages	Exhibit No.: A-104 (MJF-1)	5,431	271	5,703
23	Digitizing Company Records Expense	Exhibit No.: A-104 (MJF-1)	-		1,260
24	Incentive Compensation	Exhibit No.: A-72 (AMC-3)	2,711	(458)	2,253
25	Job Work Expense	WP-HLP-20	1,256	-	1,256
26	Interest expense on security deposits	WP-HLP-19	327	-	327
27	Return On - Forestry Regulatory Asset	Exhibit No.: A-180 (HLP-58)	-	2,821	2,821
28	DR Reconcilation	Exhibit No.: Exhibit No.: A-112 (AMG-5) and A-116 (AMG-9)	-	(2,718)	(2,718)
29	Total operation and maintenance expenses	Sum Lines 1 - 27	712,509	85,023	796,074

Schedule: C-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Inflation and Merit Increases Included in Operation and Maintenance Expenses
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-42)
Schedule: C-5.1
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Historical 12 Months Ended 12/31/2025	(d) Inflation Applied to Projected Test Year	(e) Scope / Cost Increases Net of Productivity Gains	(f) Projected 12 Months Ended 4/30/2028
						(c) + (d) + (e)
1	Electric Division - Electric & Common	Exhibit No.: A-92 (EMD-8)	283,019	17,677	20,960	321,655
2	Forestry	Exhibit No.: A-191 (SES-6)	135,176	8,443	24,130	167,749
3	Generation	Exhibit No.: A-197 (MEW-4)	111,407	6,958	(15,883)	102,482
4	Operations Support	Exhibit No.: A-136 (QAG-2)	16,690	1,042	(1,567)	16,166
5	Information Technology Operations	Exhibit No.: A-17 (SHB-1)	49,197	3,073	8,051	60,320
6	Information Technology Investments	Exhibit No.: A-19 (SHB-3)	7,698	481	1,876	10,055
7	Information Technology - Security Operations	Exhibit No.: A-17 (SHB-1)	10,179	636	2,606	13,421
8	Information Technology - Security Investments	Exhibit No.: A-19 (SHB-3)	814	51	682	1,547
9	Customer Interactions	Exhibit No.: A-110 (AMG-2)	22,524	1,407	4,206	28,137
10	Billing & Payment	Exhibit No.: A-110 (AMG-2)	10,882	680	1,078	12,640
11	Demand Response	Exhibit No.: A-111 (AMG-4)	29,406	1,837	2,386	33,628
12	Pension Plans A/B	Exhibit No.: A-125 (KKG-1)	(47,918)	-	(13,934)	(61,852)
13	Defined Company Contribution Plan	Exhibit No.: A-125 (KKG-1)	16,512	-	1,070	17,582
14	401(k) Employees' Savings Plan	Exhibit No.: A-125 (KKG-1)	13,321	-	1,379	14,700
15	Active Health Care/Life Insurance/LTD	Exhibit No.: A-125 (KKG-1)	32,073	-	4,485	36,558
16	Retiree Health Care and Life Insurance	Exhibit No.: A-125 (KKG-1)	(49,261)	-	(3,500)	(52,761)
17	Other Benefits	Exhibit No.: A-125 (KKG-1)	2,822	176	54	3,052
18	Pension/OPEB Volatility Mechanism Amortization	Exhibit No.: A-125 (KKG-1)	(1,655)	-	(2,282)	(2,530)
19	Corporate Services	Exhibit No.: A-105 (MJF-2)	24,280	1,516	(0)	25,796
20	Insurance Expense	Exhibit No.: A-105 (MJF-2)	14,143	883	240	15,266
21	Uncollectible Expense	Exhibit No.: A-105 (MJF-2)	21,475	1,341	(1,256)	21,561
22	Injuries & Damages	Exhibit No.: A-105 (MJF-2)	5,431	339	(68)	5,703
23	Digitizing Company Records Expense	Exhibit No.: A-105 (MJF-2)	-	-	1,260	1,260
24	Incentive Compensation	Exhibit No.: A-72 (AMC-3)	2,711	140	(598)	2,253
25	Job Work Expense	WP-HLP-20	1,256	-	-	1,256
26	Interest expense on security deposits	WP-HLP-19	327	-	-	327
27	Return On - Forestry Regulatory Asset	Exhibit No.: A-180 (HLP-58)	-	-	-	2,821
28	DR Reconcilation	Exhibit No.: Exhibit No.: A-112 (AMG-5) and A-116 (AMG-9)	-	-	-	(2,718)
29	Projected inflation of other O&M expenses	Sum Lines 1 - 27	712,509	46,681	35,374	796,074

Schedule: C-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation and Amortization Expenses
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-43)
Schedule: C-6
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Distribution	WP-HLP-25 Col. (d), Line 60	450,018
2	Production (Hydro)	WP-HLP-25 Col. (d), Line 61	47,478
3	Production (Hydro Ludington)	WP-HLP-25 Col. (d), Line 62	16,885
4	Production (Steam)	WP-HLP-25 Col. (d), Line 63	18,328
5	Production (Solar)	WP-HLP-25 Col. (d), Line 64	8,336
6	Production (Other)	WP-HLP-25 Col. (d), Line 65	43,902
7	Intangibles	WP-HLP-25 Col. (d), Line 66	36,535
8	E-GP Structures	WP-HLP-25 Col. (d), Line 67	4,833
9	E-GP Computers	WP-HLP-25 Col. (d), Line 68	2,086
10	E-GP Transportation	WP-HLP-25 Col. (d), Line 69	-
11	E-GP Other	WP-HLP-25 Col. (d), Line 70	4,464
12	C-GP Structures	WP-HLP-25 Col. (d), Line 71	2,638
13	C-GP Computers	WP-HLP-25 Col. (d), Line 72	11,785
14	C-GP Transportation	WP-HLP-25 Col. (d), Line 73	-
15	C-GP Other	WP-HLP-25 Col. (d), Line 74	5,843
16	Production Acq Adjustment	WP-HLP-25 Col. (d), Line 75	19,856
17	PowerMiDrive	A-173 (HLP-51) Line 16	4,876
18	PowerMiFleet	A-173 (HLP-51) Line 17	2,445
19	Karn Plant Retention and Separation Costs	A-174 (HLP-52) Line 12	0
20	Campbell Plant Retention and Separation Costs	A-174 (HLP-52) Line 13	3,464
21	Campbell Net Book Value Amortization	A-175 (HLP-53) Line 2 + 6	128,096
22	Karn 1-2 Decommissioning Costs Amortization	A-176 (HLP-54) Line 6, col. j	12,201
23	Campbell Decommissioning Costs Amortization	A-176 (HLP-54) Line 14, col. j	4,877
24	Karn 1-2 and Classic 7 Ash Disposal Amortization	A-177 (HLP-55) Line 6, col. (j)	11,237
25	Storm Deferral Amortization	A-184 (HLP-62) Line 3	17,332
26	Case No. U-21502 (Itron Refund)	A-185 (HLP-63) Line 3	(3,000)
27	Total depreciation and amortization expenses	Sum Lines 1 - 24	854,516

Schedule: C-7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
General Taxes
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-44)
Schedule: C-7
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Total Amount
1	Real and personal property taxes	Exhibit No.: A-161 (BJV-1)	301,800
	Projected payroll taxes		
2	Total payroll taxes - historical year	Exhibit No.: A-3 (HLP-16)	25,833
3	Inflation factor 2026	WP-HLP-38	102.9%
4	Inflation factor 2027	WP-HLP-38	102.5%
5	Inflation factor 2028	WP-HLP-38	100.7%
6	Total payroll taxes - projected year	Line 2 * Line 3 * Line 4 * Line 5	27,447
	Projected other general taxes		
7	State MPSC assessment - historical year	Exhibit No.: A-3 (HLP-16)	12,771
8	Total operating revenues - historical year	Exhibit No.: A-3 (HLP-11)	5,522,103
9	Average State MPSC assessment rate	Line 7 / Line 8	0.23%
10	Total operating revenues - projected year	Exhibit No.: A-13 (HLP-39)	5,691,456
11	Average State MPSC assessment rate	Line 9	0.23%
12	Projected State MPSC assessment	Line 10 * Line 11	13,163
13	Incremental change in State MPSC assessment	Line 12 - Line 7	392
14	Other general taxes - historical year	Exhibit No.: A-3 (HLP-16)	12,902
15	Total other general taxes - projected year	Line 13 + Line 14	13,294
16	Total general taxes	Line 1 + Line 6 + Line 15	342,541

Schedule: C-8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Federal Income Taxes
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-45)
Schedule: C-8
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Source	(c) Amount
1	Operating revenues	Exhibit No.: A-13 (HLP-39)	5,691,456
2	Power supply costs	Exhibit No.: A-13 (HLP-40)	(2,765,982)
3	Other O&M expenses	Exhibit No.: A-13 (HLP-41)	(796,074)
4	Depreciation and amortization expenses	Exhibit No.: A-13 (HLP-43)	(854,516)
5	General taxes	Exhibit No.: A-13 (HLP-44)	(342,541)
6	State income taxes	Exhibit No.: A-13 (HLP-46), Line 20 * -1	(36,041)
7	Other (local) income taxes	Exhibit No.: A-13 (HLP-47), Line 18 * -1	(1,182)
8	Net operating income	Sum Lines 1 - 7	895,120
9	Allowable interest expense	Exhibit No.: A-13 (HLP-49)	(337,434)
10	Allowable JDITC interest expense	Exhibit No.: A-13 (HLP-50)	(1,604)
11	Pre-tax operating income	Sum Lines 8 - 10	556,083
	Permanent Differences		
12	Meals and entertainment	Tax Department	997
13	Non-deductible parking	Tax Department	103
14	Total permanent differences	Sum Lines 12 - 13	1,100
	Temporary Differences		
15	Book depreciation	Exhibit No.: A-13 (HLP-43)	854,516
16	Tax depreciation	Tax Department	(820,513)
17	263A - mixed service costs deduction	Tax Department	(27,306)
18	Tax repairs	Tax Department	(200,000)
19	Contributions in aid of construction/Grants	Tax Department	15,854
20	Cost of removal	Tax Department	(229,623)
21	Gain/loss on ACRS/MACRS dispositions	Tax Department	(12,839)
22	Software expense	Tax Department	-
23	Tax interest during construction	Tax Department	106,214
24	Bad debt allowance	Tax Department	-
25	OPEB - book expense	Exhibit No.: A-13 (HLP-41), Line 16	(52,761)
26	OPEB - payments	Tax Department	-
27	Other regulatory assets	Tax Department	1,906
28	Pension book expense	Exhibit No.: A-13 (HLP-41), Line 12	(61,852)
29	Pension - payments	Tax Department	-
30	Securitization Amortization	Tax Department	123,550
31	Premium, discount & debt expense amortization	Tax Department	2,569
32	Real and personal property taxes	Tax Department	(53,173)
33	Renewable energy reserve	Tax Department	(6,490)
34	Deferred state income taxes	Tax Department	26,946
35	Deferred city income taxes	Tax Department	822
36	Total temporary differences	Sum Lines 15 - 33	(332,181)
37	Federal taxable income	Line 11 + Line 14 + Line 36	225,002
	Calculation of Current Federal Income Tax Expenses		
38	Current federal income taxes	Line 37 * 21.00% Federal Income Tax Rate	47,250
39	Production tax credits	Tax Department	-
40	Research & development credit	Tax Department	(1,292)
41	Total current federal income tax exenses	Line 38 + Line 40	45,958
	Calculation of Deferred Federal Income Tax Expenses		
42	Deferred federal income taxes	(Line 36 * 21.00% Federal Income Tax Rate) * -1	69,758
43	FAS 109	Tax Department	(106)
44	Investment tax credit amortization	Tax Department	(5,653)
45	TCJA amortization - ARAM	Tax Department	(30,463)
46	TCJA amortization - non-ARAM	Tax Department	(4,148)
47	TCJA Tracker	Tax Department	2,104
48	Repealed Medicare subsidy benefit	Tax Department	-
49	Total deferred federal income tax expenses	Sum Lines 42 - 48	31,492
50	Total federal income taxes	Line 41 + Line 49	77,450

Schedule: C-9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
State Income Taxes
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-46)
Schedule: C-9
Page: 1 of 1
P Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Source	(c) Amount
1	Operating revenues	Exhibit No.: A-13 (HLP-39)	5,691,456
2	Power supply costs	Exhibit No.: A-13 (HLP-40)	(2,765,982)
3	Other O&M expenses	Exhibit No.: A-13 (HLP-41)	(796,074)
4	Depreciation and amortization expenses	Exhibit No.: A-13 (HLP-43)	(854,516)
5	General taxes	Exhibit No.: A-13 (HLP-44)	(342,541)
6	Net operating income	Sum Lines 1 - 5	932,344
7	Interest expense	Exhibit No.: A-13 (HLP-49)	(337,434)
8	Interest synchronization	Exhibit No.: A-13 (HLP-50)	(1,604)
9	Pre-tax operating income	Sum Lines 6 - 8	593,306
10	Total permanent differences	Exhibit No.: A-13 (HLP-45)	1,100
11	Schedule M temp diff, excluding DSIT and DCIT	Exhibit No.: A-13 (HLP-45)	(359,948)
12	Depreciation/gain-loss adjustment	Tax Department	(60,883)
13	State taxable income	Sum Lines 9 - 12	173,574
14	Current state income taxes	Line 13 * 5.24% State Income Tax Rate	9,095
	Calculation of Deferred State Income Tax Expense		
15	Deferred state income tax expenses, tax effected	((Lines 11 + 12) * 5.24% State Income Tax Rate) * -1	22,052
16	FAS 109 - AFUDC-equity flow-through reversal	Tax Department	172
17	Deferred - amortization of Medicare Subsidy benefit - state	Tax Department	-
18	Deferred - amortization of state income tax transition reg asset	Tax Department	4,722
19	Deferred state income taxes	Sum Lines 15 - 18	26,946
20	Total state income taxes	Line 14 + Line 19	36,041

Schedule: C-10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Other (or Local) Taxes
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-47)
Schedule: C-10
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Operating revenues	Exhibit No.: A-13 (HLP-39)	5,691,456
2	Power supply costs	Exhibit No.: A-13 (HLP-40)	(2,765,982)
3	Other O&M expenses	Exhibit No.: A-13 (HLP-41)	(796,074)
4	Depreciation and amortization expenses	Exhibit No.: A-13 (HLP-43)	(854,516)
5	General taxes	Exhibit No.: A-13 (HLP-44)	(342,541)
6	State income taxes	Exhibit No.: A-13 (HLP-46)	(36,041)
7	Net operating income	Sum Lines 1 - 6	896,303
8	Interest expense	Exhibit No.: A-13 (HLP-49)	(337,434)
9	Interest synchronization	Exhibit No.: A-13 (HLP-50)	(1,604)
10	Pre-tax operating income	Sum Lines 7 - 9	557,265
11	Total permanent differences	Exhibit No.: A-13 (HLP-45)	1,100
12	Schedule M temp diff, excluding DCIT	Exhibit No.: A-13 (HLP-45)	(333,003)
13	Other (local) taxable income	Sum Lines 10 - 12	225,362
14	Current other (local) income taxes	Line 13 * 0.16% Other (Local) Income Tax Rate	361
	Calculation of Deferred Other (Local) Income Tax Expenses		
15	Deferred other (local) income tax expenses, tax effected	(Line 12 * 0.16% Other (Local) Income Tax Rate) * -1	533
16	Deferred - amortization of reg asset	Exhibit No.: A-13 (HLP-45)	289
17	Total deferred other (local) income taxes	Line 15 + Line 16	822
18	Total other (local) income taxes	Line 14 + Line 17	1,182

Schedule: C-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Allowance for Funds Used During Construction
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-48)
Schedule: C-11
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No	(a) Description	(b) Source	(c) Amount
1	Total allowance for funds used during construction	WP-HLP-26	17,040

Schedule: C-12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Income Tax Effect of Interest
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-49)
Schedule: C-12
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-12 (HLP-31)	17,022,569
2	Weighted cost of debt {1}	Exhibit No.: A-14 (MRB-1), Schedule D-1	0.0198
3	Allowable interest expense	Line 1 * Line 2	337,434
4	Pro forma interest expense - historical year	Exhibit No.: A-3 (HLP-21)	266,379
5	Increase/ (decrease) in allowable interest deduction	Line 3 - Line 4	71,055
6	Impact on taxable income	Line 5 * -1	(71,055)
7	Impact on state and local income taxes	Line 6 * 5.40% State and Local Income Tax Rate	(3,837)
8	Impact on federal taxable income	Line 6 - Line 7	(67,218)
9	Impact on federal income taxes	Line 8 * 21.00% Federal Income Tax Rate	(14,116)
10	Total impact on net operating income	(Line 7 + Line 9) * -1	17,953

Notes

{1} Excludes JDITC

Schedule C-13

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Interest Synchronization Adjustment
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-13 (HLP-50)
Schedule: C-13
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-12 (HLP-31)	17,022,569
2	JDITC debt-related portion of the capital structure	Exhibit No.: A-14 (MRB-1), Schedule D-1	0.0020
3	Portion of rate base funded by JDITC	Line 1 * Line 2	33,962
4	Cost of JDITC - debt portion	Exhibit No.: A-14 (MRB-1), Schedule D-1	0.0472
5	Allowable JDITC interest expense	Line 3 * Line 4	1,604
6	Allowable JDITC interest expense - historical year	Exhibit No.: A-3 (HLP-22)	1,319
7	Increase/ (decrease) in allowable JDITC interest expense	Line 5 - Line 6	285
8	Impact on taxable income	Line 7 * -1	(285)
9	Impact on state and local income taxes	Line 8 * 5.40% State and Local Income Tax Rate	(15)
10	Impact on federal taxable income	Line 8 - Line 9	(269)
11	Impact on federal income taxes	Line 10 * 21.00% Federal Income Tax Rate	(57)
12	Total impact on net operating income	(Line 9 + Line 11) * -1	72

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Asset and Amortization Expense of
PowerMiDrive and PowerMiFleet
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-173 (HLP-51)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Actual 2020	(d) Actual 2021	(e) Actual 2022	(f) Actual 2023	(g) Actual 2024	(h) Actual 2025	(i) Forecast 2026	(j) Forecast 2027	(k) Forecast 2028
1	PowerMiDrive electric vehicle expenditures	Ex. A-110 (AMG-2)	2,896	2,947	3,876	5,116	7,734	8,945			
2	2020 amortization expense	Line 1, col. (c) / 5 years	-	579	579	579	579	579			
3	2021 amortization expense	Line 1, col. (d) / 5 years	-	-	589	589	589	589	589		
4	2022 amortization expense	Line 1, col. (e) / 5 years	-	-	-	775	775	775	775	775	
5	2023 amortization expense	Line 1, col. (f) / 5 years	-	-	-	-	1,023	1,023	1,023	1,023	1,023
6	2024 amortization expense	Line 1, col. (g) / 5 years	-	-	-	-	-	1,547	1,547	1,547	1,547
7	2025 amortization expense	Line 1, col. (h) / 5 years							1,789	1,789	1,789
8	Total PowerMiDrive amortization expense	Sum of Lines 2 through 7	-	579	1,169	1,944	2,967	4,514	5,724	5,134	4,359
9	PowerMiFleet electric vehicle expenditures	Ex. A-110 (AMG-2)	-	1,009	1,785	2,906	3,545	4,585			
10	2021 amortization expense	Line 9, col. (d) / 5 years	-	-	202	202	202	202	202		
11	2022 amortization expense	Line 9, col. (e) / 5 years	-	-	-	357	357	357	357	357	
12	2023 amortization expense	Line 9, col. (f) / 5 years	-	-	-	-	581	581	581	581	581
13	2024 amortization expense	Line 9, col. (g) / 5 years	-	-	-	-	-	709	709	709	709
14	2025 amortization expense	Line 9, col. (h) / 5 years							917	917	917
15	Total PowerMiFleet amortization expense	Sum of Lines 10 through 14	-	-	202	559	1,140	1,849	2,766	2,564	2,207

Line No.			12 Months Ending 4/30/2027	12 Months Ending 4/30/2028	Average Balance 4/30/2028
16	Test year PowerMiDrive amortization expens	(Line 8, col. (i)) ÷ 12 * 8) + (Line 8, col. (j)) ÷ 12 * 4)		4,876	
17	Test year PowerMiFleet amortization expens	(Line 15, col. (i)) ÷ 12 * 8) + (Line 15, col. (j)) ÷ 12 * 4)		2,445	
18	Total test year amortization expense	Line 16 + Line 17		7,321	
19	PowerMiDrive deferred balance	See Notes {1}, {2}, and {3} below, respectively	12,907	8,031	10,469
20	PowerMiFleet deferred balance	See Notes {4}, {5}, and {6} below, respectively	6,460	4,015	5,237

Notes

{1} (Sum of line 1, col. (c) through (i) - sum of line 8, col. (c) through (i)) - ((line 8, col. (j) ÷ 12 * 4)
{2} Sum of line 1, col. (c) through (j) - sum of line 8, col. (c) through (j) - ((line 8, col. (k) ÷ 12 * 4)
{3} (Line 19, col. (c) + line 19, col. (d)) ÷ 2
{4} (Sum of line 9, col. (d) through (i) - sum of line 15, col. (d) through (i)) - ((line 15, col. (j) ÷ 12 * 4)
{5} Sum of line 9, col. (d) through (j) - sum of line 15, col. (d) through (j) - ((line 15, col. (k) ÷ 12 * 4)
{6} (Line 20, col. (c) + line 20, col. (d)) ÷ 2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Asset and Amortization Expense of
Karn & Campbell Plant Retention & Separation Costs
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-174 (HLP-52)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Actual 2022	(d) Actual 2023	(e) Actual 2024	(f) Actual 2025	(g) Forecast 2026	(h) Forecast 2027	(i) Forecast 2028
1	Karn deferred retention/separation costs	SAP Accounts 1670070 & 1757310	4,828	1,501	0				
2	2022 amortization expense	Line 1, col. (c) / 3 years	-	1,609	1,609	1,609	-	-	-
3	2023 amortization expense	Line 1, col. (d) / 3 years	-	-	500	500	500	-	-
4	2024 amortization expense	Line 1, col. (e) / 3 years	-	-	-	0	0	0	-
5	Total amortization expense	Sum of Lines 2 through 4	-	1,609	2,110	2,110	500	0	-
6	Campbell deferred retention/separation costs	SAP Accounts 1670080 & 1757320	23,904	15,847	8,626	4,641			
7	2022 amortization expense	Line 6, col. (c) / 3 years	-	7,968	7,968	7,968	-	-	
8	2023 amortization expense	Line 6, col. (d) / 3 years	-	-	5,282	5,282	5,282	-	
9	2024 amortization expense	Line 6, col. (e) / 3 years	-	-	-	2,875	2,875	2,875	
10	2025 amortization expense	Line 6, col. (f) / 3 years	-	-	-	-	1,547	1,547	1,547
11	Total amortization expense	Sum of Lines 7 through 10	-	7,968	13,250	16,126	9,705	4,422	1,547

Line No.	Description	Source	12 Months Ending 4/30/2027	12 Months Ending 4/30/2028	Average Balance 4/30/2028
12	Test year Karn amortization expense	(Line 5, col. (g)) ÷ 12 * 8) + (Line 5, col. (h)) ÷ 12 * 4)		0	
13	Test year Campbell amortization expense	(Line 11, col. (g)) ÷ 12 * 8) + (Line 11, col. (h)) ÷ 12 * 4)		3,464	
14	Total test year amortization expense	Line 12 + Line 13		3,464	
15	Karn deferred balance	See Notes {1}, {2}, and {3} below, respectively	0	0	0
16	Campbell deferred balance	See Notes {4}, {5}, and {6} below, respectively	4,495	1,031	2,763

Notes

{1} (Sum of line 1, col. (c) through (g) - sum of line 5, col. (c) through (g)) - ((line 5, col. (h) ÷ 12 * 4)
{2} Sum of line 1, col. (c) through (h) - sum of line 5, col. (c) through (h) - ((line 5, col. (i) ÷ 12 * 4)
{3} (Line 15, col. (c) + line 15, col. (d)) ÷ 2
{4} (Sum of line 6, col. (c) through (g) - sum of line 11, col. (c) through (g)) - ((line 11, col. (h) ÷ 12 * 4)
{5} Sum of line 6, col. (c) through (h) - sum of line 11, col. (c) through (h) - ((line 11, col. (i) ÷ 12 * 4)
{6} (Line 16, col. (c) + line 16, col. (d)) ÷ 2

MICHIGAN PUBLIC SERVICE COMMISSIOI
Consumers Energy Company
Regulatory Asset and Amortization Expense of th
Net Book Value of Campbell Plant 1, 2, and 3
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-175 (HLP-53)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
Line No.	**Description**	**Source**	**Actual 12/31/2025**	**4 Months Ending 04/30/2026**	**12 Months Ending 04/30/2027**	**12 Months Ending 04/30/2028**	**12 Months Ending 04/30/2029**	**12 Months Ending 04/30/2030**	**12 Months Ending 04/30/2031**	**1 Months Ending 05/31/2031**									
	Campbell Units 1&2 Regulatory Asset																		
1	Beginning Balance	SAP Accounts (1032006, 1138102, and 1183203)		387,799	364,864	296,216	223,673	151,131	78,588	6,045									
2	Amortization Expense	{a}		(22,934)	(68,649)	(72,543)	(72,543)	(72,543)	(72,543)	(6,045)									
3	Ending Balance	Sum of Line 1 + Line 2	387,799	364,864	296,216	223,673	151,131	78,588	6,045	(0)									
					-														
4	13-Month Average Balance					259,945													

			Actual 12/31/2025	**4 Months Ending 04/30/2026**	**12 Months Ending 04/30/2027**	**12 Months Ending 04/30/2028**	**12 Months Ending 04/30/2029**	**12 Months Ending 04/30/2030**	**12 Months Ending 04/30/2031**	**12 Months Ending 04/30/2032**	**12 Months Ending 04/30/2033**	**12 Months Ending 04/30/2034**	**12 Months Ending 04/30/2035**	**12 Months Ending 04/30/2036**	**12 Months Ending 04/30/2037**	**12 Months Ending 04/30/2038**	**12 Months Ending 04/30/2039**	**12 Months Ending 04/30/2040**	**1 Months Ending 05/31/2040**
	Campbell Unit 3 Regulatory Asse																		
5	Beginning Balance	SAP Accounts (1032004, 1138100, and 1183200)		802,714	783,734	726,824	671,270	615,717	560,164	504,610	449,057	393,503	337,950	282,397	226,843	171,290	115,736	60,183	4,629
6	Amortization Expense	{b}		(18,980)	(56,910)	(55,553)	(55,553)	(55,553)	(55,553)	(55,553)	(55,553)	(55,553)	(55,553)	(55,553)	(55,553)	(55,553)	(55,553)	(55,553)	(4,629)
7	Ending Balance	Sum of Line 5 + Line 6	802,714	783,734	726,824	671,270	615,717	560,164	504,610	449,057	393,503	337,950	282,397	226,843	171,290	115,736	60,183	4,629	(0)
					-														
8	13-Month Average Balance					699,047													

Notes

{a} Amortization Expense for Campbell Units 1&2 reflects the previously approved (in U-21585 and U-21870) annual amortization expenses through April 30, 2027. The total amortization expense for the projected test year period ending April 30, 2028 is $72,543, which represents the annual straightline amortization required to fully amortize the remaining regulatory asset balance to zero over its originally approved life ending in May 2031

{b} Amortization Expense for Campbell Unit 3 reflects the previously approved (in U-21585 and U-21870) annual amortization expenses through April 30, 2027. The total amortization expense for the projected test year period ending April 30, 2028 is $55,553, which represents the annual straightline amortization required to fully amortize the remaining regulatory asset balance to zero over its originally approved life ending in May 2040.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Asset and Amortization Expense of the
Karn & Campbell Plant Decommissioning Costs
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-176 (HLP-54)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Actual 2022	(d) Actual 2023	(e) Actual 2024	(f) Actual 2025	(g) Forecast 2026	(h) Forecast 2027	(i) Forecast 2028	(j) Test Period Amortization
1	Karn 1-2 deferred decommissioning costs	SAP Account 1670304 and 1757302	11,533	24,895	22,014	16,491				
2	2022 amortization expense	Line 1, col. (c) / 96 months (amortization beginning in March 2024)	-	-	1,201	1,442	1,442	1,442	1,442	1,442
3	2023 amortization expense	Line 1, col. (d) / 84 months (amortization beginning in April 2025)	-	-	-	2,667	3,556	3,556	3,556	3,556
4	2024 amortization expense	Line 1, col. (e) / 72 months (amortization beginning in May 2026)					2,446	3,669	3,669	3,669
5	2025 amortization expense	Line 1, col. (f) / 56 months(amortization beginning in May 2027)						2,356	3,534	3,534
6	Total amortization expense	Sum of Lines 2 through 5	-	-	1,201	4,109	7,444	11,023	12,201	12,201
7	Campbell deferred decommissioning costs	SAP Account 1670302, 1670303, 1757306 and 1757307	1,382	15,353	5,244	4,503				
8	Campbell return on decommissioning costs	WP-HLP-21				2,229				
9	2022 amortization expense	Line 7, col. (c) / 10 years (amortization beginning in March 2024)	-	-	115	138	138	138	138	138
10	2023 amortization expense	Line 7, col. (d) / 10 years (amortization beginning in April 2025)	-	-	-	1,151	1,535	1,535	1,535	1,535
11	2024 amortization expense	Line 7, col. (e) / 10 years (amortization beginning in May 2026)					350	524	524	524
12	2025 amortization expense (decommissioning costs	Line 7, col. (f) / 10 years (amortization beginning in May 2027)						300	450	450
13	2025 return on decommissioning costs	Line 8 (8 months included in 2027 and 4 months included in 2028 in alignement with the test year)						1,486	743	2,229
14	Total amortization expense	Sum of Lines 9 through 13	-	-	115	1,290	2,023	3,984	3,391	4,877
			12 Months Ending 4/30/2027	**12 Months Ending 4/30/2028**	**Average Balance 4/30/2028**					
15	Karn 1-2 deferred balance	See Notes {1}, {2}, and {3} below, respectively	59,290	47,089	53,189					

Notes

{1} (Sum of line 1, col. (c) through (g) - sum of line 6, col. (c) through (g)) - ((Sum of lines 2 - 4, col. (h)) ÷ 12 * 4)
{2} Sum of line 1, col. (c) through (g) - sum of line 7, col. (c) through (h) - ((line 7, col. (i) ÷ 12 * 4)
{3} (Line 15, col. (c) + line 15, col. (d)) ÷ 2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Asset and Amortization Expense of the
Karn, Campbell, and Classic 7 Ash Disposal Costs
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-177 (HLP-55)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) 2022	(d) 2023	(e) 2024	(f) 2025	(g) 2026	(h) 2027	(i) 2028	(j) Test Period Amortization
1	Karn 1-2, Classic 7, and Campbell Ash Disposal Costs Deferre	SAP Accounts 1670300, 1670301, 1757303 and 175730E	11,075	18,273	51,402	31,617				
2	2022 amortization expense	Line 1, col. (c) / 10 years (amortization beginning in March 2024	-	-	923	1,108	1,108	1,108	1,108	1,108
3	2023 amortization expense	Line 1, col. (d) / 10 years (amortization beginning in April 2025	-	-	-	1,370	1,827	1,827	1,827	1,827
4	2024 amortization expense	Line 1, col. (e) / 10 years (amortization beginning in May 2026					3,427	5,140	5,140	5,140
5	2025 amortization expense	Line , col. (f) / 10 years (amortization beginning in May 2027						2,108	3,162	3,162
6	Total amortization expense	Sum of Lines 2 through 5	-	-	923	2,478	6,362	10,183	11,237	11,237
			12 Months Ending 4/30/2027	**12 Months Ending 4/30/2028**	**Average Balance 4/30/2028**					
7	Ash Disposal Costs Deferred Balance	See Notes {1}, {2}, and {3} below, respectively	99,913	88,676	94,294					

Notes

{1} (Sum of line 1, col. (c) through (g) - sum of line 6, col. (c) through (g)) - ((Sum of lines 2 - 4, col. (h)) ÷ 12 * 4
{2} (Sum of line 1, col. (c) through (h) - sum of line 6, col. (c) through (h)) - ((line 6, col. (i) ÷ 12 * 4
{3} (Line 7, col. (c) + line 7, col. (d)) ÷ 2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Asset and Amortization Expense of the
Pension and OPEB Volatility Mechanism
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-178 (HLP-56)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028
1	Pension volatility mechanism asset / (liability)	WP-KKG-3, 4, 5, and 6	(11,466)	(10,729)	3,016	(11,707)	(3,183)	
2	2023 amortization expense	Line 1, col. (c) / 10 years	-	(1,147)	(1,147)	(1,147)	(1,147)	(1,147)
3	2024 amortization expense	Line 1, col. (d) / 10 years	-	-	(1,073)	(1,073)	(1,073)	(1,073)
4	2025 amortization expense	Line , col. (e) / 10 years	-	-	-	302	302	302
5	2026 amortization expense	Line 1, col. (f) / 10 years					(1,171)	(1,171)
6	2027 amortization expense	Line 1, col. (g) / 10 years						(318)
7	Total amortization expense	Sum of Lines 2 through 6	-	(1,147)	(2,220)	(1,918)	(3,089)	(3,407)
8	OPEB volatility mechanism asset / (liability)	WP-KKG-3, 4, 5, and 6	23,302	(3,579)	(1,609)	(10,561)	(2,725)	
9	2023 amortization expense	Line 8, col. (d) / 10 years	-	2,330	2,330	2,330	2,330	2,330
10	2024 amortization expense	Line 8, col. (e) / 10 years	-	-	(358)	(358)	(358)	(358)
11	2025 amortization expense	Line 8, col. (f) / 10 years	-	-	-	(161)	(161)	(161)
12	2026 amortization expense	Line 8, col. (f) / 10 years					(1,056)	(1,056)
13	2027 amortization expense	Line 8, col. (g) / 10 years						(272)
14	Total amortization expense	Sum of Lines 9 through 13	-	2,330	1,972	1,811	755	483

Line No.	(a) Description	(b) Source	12 Months Ending 4/30/2027	12 Months Ending 4/30/2028	Average Balance 4/30/2028
15	Test year pension amortization expense	(Line 7, col. (g)) ÷ 12 * 8) + (Line 7, col. (h)) ÷ 12 * 4)		(3,195)	
16	Test year OPEB amortization expense	(Line 14, col. (g)) ÷ 12 * 8) + (Line 14, col. (h)) ÷ 12 * 4)		665	
17	Total test year amortization expense	Line 15 + Line 16		(2,530)	
18	Pension volatility mechanism deferred balanc	See Notes {1}, {2}, and {3} below, respectively	(25,635)	(24,562)	(25,098)
19	OPEB volatility mechanism deferred balance	See Notes {4}, {5}, and {6} below, respectively	280	(2,201)	(961)

Notes

{1} ((Sum of line 1, col. (c) through (e) + (Line 1, col. (f) ÷ 12 * 4)) - sum of line 7, col. (c) through (f)) - ((line 7, col. (g) ÷ 12 * 4)
{2} (Sum of line 1, col. (c) through (f) +(line 1, col. (g)÷ 12 * 4)) - sum of line 8, col. (c) through (g) - ((line 8, col. (h) ÷ 12 * 4)
{3} (Line 18, col. (c) + line 18, col. (d)) ÷ 2
{4} (Sum of line 8, col. (c) through (f) - sum of line 14, col. (c) through (f)) - ((line 14, col. (g) ÷ 12 * 4)
{5} Sum of line 8, col. (c) through (g) - sum of line 14, col. (c) through (g) - ((line 14, col. (h) ÷ 12 * 4)
{6} (Line 19, col. (c) + line 19, col. (d)) ÷ 2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Campbell Regulatory Asset - Return On
For the Projected 12-Month Period Ending April 30, 2028
(000)

Case No.: U-22070
Exhibit No.: A-179 (HLP-57)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) Amount
	Return on Campbell Regulatory Asset		
1	Campbell 1-2 Regulatory Asset - Average Balance	A-175 (HLP-53)	259,945
2	Campbell 3 Regulatory Asset - Average Balance	A-175 (HLP-53)	699,047
3	Total Campbell Average Regulatory Asset Balance Test Year	Line 1 + Line 2	958,992
	Cost of Capital		
4	Pre-tax Weighted Average Cost of Capital[1]	Note 1	7.40%
5	Return on Campbell Regulatory Asset	Line 3 * Line 4	70,954

Notes

1	Pre-tax WACC as proposed in this case was recalculated using 9% ROE in accordance with U-21090 order dated June 23, 2022	WP-HLP-39	7.40%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Asset Summary of the
Forestry Ramp-Up
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-180 (HLP-58)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) 2026	(d) 2027	(e) 2028
1	Deferral to Forestry Ramp-Up Regulatory Asset	A-186 (SES-1), Line 35	14,410	46,662	69,545
2	Cumulative Balance - Forestry Ramp-Up Regulatory Asset		14,410	61,072	130,617
			12 Months Ending 4/30/2027	**12 Months Ending 4/30/2028**	**Average Balance 4/30/2028**
3	Forestry Ramp-Up Regulatory Asset Balance	See Notes {1}, {2}, and {3} below, respectively	29,964	84,253	57,109
	Return on Forestry Ramp-Up Regulatory Asset				
4	Test Year Average Balance - Regulatory Asset				57,109
5	Short Term Borrowing Rate	{4}			4.94%
6	Return on Forestry Deferral				**2,821**

Notes

{1} Line 2, col. (c) + Line 1 col (d) ÷ 12 * 4
{2} Line 2, col. (d) + Line 1 col (e) ÷ 12 * 4
{3} (Line 4, col. (c) + line 4, col. (d)) ÷ 2
{4} In Case No. U-21870, the Commission ordered the Company to apply the short-term debt rate as the return on Forestry Ramp-Up deferred expenses.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response Revenue Requirement
(000)

Case No.: U-22070
Exhibit No.: A-181 (HLP-59)
Page: 1 of 3
Witness: HLPatton
Date: June 2026

Total Demand Response

Line	Description	Total	Source
(a)	(b)	(c)	(d)
1	**Residential Revenue Requirement**	**$19,188**	Exhibit A-181 (HLP-59), p 2
2	**C&I Revenue Requirement**	**$21,289**	Exhibit A-181 (HLP-59), p 3
3	**2025 Reconciliation - Regulatory Liability**	**($10,422)**	Exhibit A-112 (AMG-5), page 1 Line 14
4	**2025 Reconciliation - Incentive**	**7,704**	Exhibit A-116 (AMG-9), Line 5
3	**Total Demand Response Revenue Requirement**	**$37,759**	Sum of Lines 1 - 4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response Revenue Requirement
(000)

Case No.: U-22070
Exhibit No.: A-181 (HLP-59)
Page: 2 of 3
Witness: HLPatton
Date: June 2026

Residential Demand Response

Line	Description	4 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028	Total	
(a)	(b)	(c)	(d)	(e)	(f)	
1	**Total Capital Spending**	$ 15	$ 60	$ 60	$ 135	Exhibit A-12 (AMG-1), Sch B-5.7
	Revenue Requirement Calculation:					
					4/30/2028 Average	
2	Beginning Plant	$ 43,686	$ 43,701	$ 43,761		
3	Closings	15	60	60		
4	Ending Plant	$ 43,701	$ 43,761	$ 43,821	$ 43,791	
5	Beginning CWIP	$ -	$ -	$ -		
6	Capital Spending	15	60	60		
7	Closings	15	60	60		
8	Ending CWIP	$ -	$ -	$ -	$ -	
9	Beginning Depreciation Reserve	$ 7,182	$ 8,065	$ 10,829		
10	Depreciation Expense [1]	882	2,765	2,769		
11	End Depreciation Reserve	$ 8,065	$ 10,829	$ 13,598	$ 12,214	
12	Total Rate Base				$ 31,578	Line 4 + Line 8 - Line11
13	Pre-Tax Rate of Return				7.85%	Exhibit A-14 (MRB-1)
14	Return on Investment				$ 2,478	Line 12 * Line 13
15	Depreciation Expense				2,769	Line 10
16	O&M				13,348	Exhibit A-111 (AMG-4)
17	R&PP Tax				594	Footnote [2]
18	**Total Residential Revenue Requirement**				**$19,188**	

Footnotes

(1)
2025 Composite Depreciation Rate	6.32%
Jan-April 2026 Depreciation portion	31.93%

(2)
Average Plant Balance Test Year	$ 43,791	
Property Tax Rate	0.01356	Source: Exh A-193 (BJV-1)
	$ 594	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response Revenue Requirement
(000)

Case No.: U-22070
Exhibit No.: A-181 (HLP-59)
Page: 3 of 3
Witness: HLPatton
Date: June 2026

Commercial and Industrial Demand Response

Line	Description	4 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	12 Mos Ending 4/30/2028	Total	
(a)	(b)	(c)	(d)	(e)	(f)	
1	**Total Capital Spending**	$ 32	$ 370	$ 120	$ 522	Exhibit A-12 (AMG-1), Sch B-5.7
	Revenue Requirement Calculation:					
					4/30/2028 Average	
2	Beginning Plant	$ 6,123	$ 6,155	$ 6,525		
3	Closings	32	370	120		
4	Ending Plant	$ 6,155	$ 6,525	$ 6,645	$ 6,585	
5	Beginning CWIP	$ 85	$ 85	$ 85		
6	Capital Spending	32	370	120		
7	Closings	32	370	120		
8	Ending CWIP	$ 85	$ 85	$ 85	$ 85	
9	Beginning Depreciation Reserve	$ 2,456	$ 2,659	$ 3,316		
10	Depreciation Expense [1]	203	657	682		
11	End Depreciation Reserve	$ 2,659	$ 3,316	$ 3,998	$ 3,657	
12	Total Rate Base				$ 3,012	Line 4 + Line 8 - Line11
13	Pre-Tax Rate of Return				7.85%	Exhibit A-14 (MRB-1)
14	Return on Investment				$ 236	Line 12 * Line 13
15	Depreciation Expense				682	Line 10
16	O&M				20,280	Exhibit A-111 (AMG-4)
17	R&PP Tax				90	Footnote [2]
18	**Total C&I Revenue Requirement**				**$21,289**	

Footnotes

(1)
2025 Composite Depreciation Rate	10.36%
Jan-April 2026 Depreciation portion	31.93%

(2)
Average Plant Balance Test Year	$ 6,670	
Property Tax Rate	0.013561729	Source: Exh A-193 (BJV-1)
	$ 90	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Deferral Summary
Test Year Ending 2/28/2026
(000)

Case No.: U-22070
Exhibit No.: A-182 (HLP-60)
Page: 1 of 6
Witness: HLPatton
Date: June 2026

Line	Description	Source Page	Amount $(000)
(a)	(b)	(c)	(d)
1	March 2025 - February 2026 Revenue Requirement	3	11,386
2	March 2026 - April 2026 Revenue Requirement	4	3,759
3	May 2026 - February 2027 Revenue Requirement	5	8,246
4	March 2027 - April 2027 Revenue Requirement	6	1,617
5	**Total Deferred Revenue Requirement**		$ 25,008

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Deferral
(000)

Case No.: U-22070
Exhibit No.: A-182 (HLP-60)
Page: 2 of 6
Witness: HLPatton
Date: June 2026

Line	Description	Actual 3/1/25 - 2/28/2026	U-21585 Approved 3/1/25 - 2/28/2026	Difference 3/1/25 - 2/28/2026	U-21870 Approved 3/1/25 - 2/28/2026	Difference 3/1/25 - 2/28/2026
(a)	(b)	(c)	(d)	(e) (c) - (d)	(f)	(g) (c) - (f)
	Capital Spending					
1	New Business	287,500	267,333	20,167	365,856	(78,357)
2	Demand Failures	318,270	206,177	112,093	188,677	129,593
3	Asset Relocations	119,176	51,859	67,317	85,294	33,882
4	**Total Capital Spending**	$ 724,945	$ 525,369	$ 199,576	$ 639,827	$ 85,118

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Deferral
(000)

Case No.: U-22070
Exhibit No.: A-182 (HLP-60)
Page: 3 of 6
Witness: HLPatton
Date: June 2026

Line	Description		Amount	Source
(a)	(b)		(c)	(d)
	Revenue Requirement Calculation:			
1	Beginning Plant in Service	$	-	
2	Additional Capital Spending		199,576	Page 2, Column (e), Line 4
3	Ending Plant	$	199,576	Line 1 + Line 2
4	Average Plant in Service	$	99,788	Average (Line 1 & Line 3)
5	Beginning Depreciation Reserve	$	-	
6	Depreciation Expense [(1)]		2,974	Line 4 x 2.98%
7	End Depreciation Reserve	$	2,974	Line 5 + Line 6
8	Average Depreciation Reserve	$	1,487	Average (Line 5 & Line 7)
9	Total Average Rate Base	$	98,301	Line 3 Less Line 8
10	Return on Investment [(1)(2)]		7,255	Line 9 x 7.38%
11	R&PP Tax [(1)]		1,158	Line 4 x 1.16%
12	**Total 3/1/25 - 2/28/26 Revenue Requirement**	**$**	**11,386**	**Line 6 + Line 10 + Line 11**

[(1)] The following rates are from the order in Case No. U-21585:

Deprecation Rates	2.98%
Pre-tax cost of capital	7.38%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Deferral
(000)

Case No.: U-22070
Exhibit No.: A-182 (HLP-60)
Page: 4 of 6
Witness: HLPatton
Date: June 2026

Line	Description		Amount	Source
(a)	(b)		(c)	(d)
	Revenue Requirement Calculation:			
1	Beginning Plant in Service	$	199,576	Page 3, Line 3
2	Additional Capital Spending		0	
3	Ending Plant	$	199,576	Line 1 + Line 2
4	Average Plant in Service	$	199,576	Average (Line 1 & Line 3)
5	Beginning Depreciation Reserve	$	2,974	
6	Depreciation Expense [1]		5,947	Line 4 x 2.98%
7	End Depreciation Reserve	$	8,921	Line 5 + Line 6
8	Average Depreciation Reserve	$	5,947	Average (Line 5 & Line 7)
9	Total Average Rate Base	$	193,629	Line 3 Less Line 8
10	Return on Investment [1][2]		14,290	Line 9 x 7.38%
11	R&PP Tax [1]		2,315	Line 4 x 1.16%
12	Total Revenue Requirement	$	22,552	Line 6 + Line 10 + Line 11
13	**March 2026 - April 2026 Deferred Revenue Requirement**	**$**	**3,759**	**Line 12 ÷ 12 x 2**

[1] The following rates are from the order in Case No. U-21585:

Deprecation Rates	2.98%
Pre-tax cost of capital	7.38%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Deferral
(000)

Case No.: U-22070
Exhibit No.: A-182 (HLP-60)
Page: 5 of 6
Witness: HLPatton
Date: June 2026

Line	Description		Amount	Source
(a)	(b)		(c)	(d)
	Revenue Requirement Calculation:			
1	Beginning Plant in Service	$	85,118	Page 2, Column (g), Line 4
2	Additional Capital Spending		0	
3	Ending Plant	$	85,118	Line 1 + Line 2
4	Average Plant in Service	$	85,118	Average (Line 1 & Line 3)
5	Beginning Depreciation Reserve	$	1,268	(Line 1 / 2) x 2.98%
6	Depreciation Expense [(1)]		2,537	Line 4 x 2.98%
7	End Depreciation Reserve	$	3,805	Line 5 + Line 6
8	Average Depreciation Reserve	$	2,537	Average (Line 5 & Line 7)
9	Total Average Rate Base	$	82,581	Line 3 Less Line 8
10	Return on Investment [(1)(2)]		6,227	Line 9 x 7.54%
11	R&PP Tax [(1)]		1,132	Line 4 x 1.33%
12	Total Revenue Requirement	$	9,895	Line 6 + Line 10 + Line 11
13	**May 2026 - Feb 2027 Deferred Revenue Requirement**	**$**	**8,246**	**Line 12 ÷ 12 x 10**

[(1)] The following rates are from the order in Case No. U-21870:

Deprecation Rates	2.98%
Pre-tax cost of capital	7.54%
Property Tax rate	1.33%

[(2)] For accounting purposes there is a contra regulatory asset account that includes the return on equity portion of the return on investment. The return on equity authorized for deferral cannot be recorded until collected.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Deferral
(000)

Case No.: U-22070
Exhibit No.: A-182 (HLP-60)
Page: 6 of 6
Witness: HLPatton
Date: June 2026

Line	Description		Amount	Source
(a)	(b)		(c)	(d)
	Revenue Requirement Calculation:			
1	Beginning Plant in Service	$	85,118	Page 2, Column (g), Line 4
2	Additional Capital Spending		0	
3	Ending Plant	$	85,118	Line 1 + Line 2
4	Average Plant in Service	$	85,118	Average (Line 1 & Line 3)
5	Beginning Depreciation Reserve	$	3,805	
6	Depreciation Expense [1]		2,537	Line 4 x 2.98%
7	End Depreciation Reserve	$	6,341	Line 5 + Line 6
8	Average Depreciation Reserve	$	5,073	Average (Line 5 & Line 7)
9	Total Average Rate Base	$	80,045	Line 3 Less Line 8
10	Return on Investment [1][2]		6,035	Line 9 x 7.54%
11	R&PP Tax [1]		1,132	Line 4 x 1.33%
12	Total Revenue Requirement	$	9,704	Line 6 + Line 10 + Line 11
13	**March 2027 - April 2027 Revenue Requirement**	**$**	**1,617**	**Line 12 ÷ 12 x 2**

[1] The following rates are from the order in Case No. U-21870:

Deprecation Rates	2.98%
Pre-tax cost of capital	7.54%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Deferral
Test Year Ending 4/30/2027
(000)

Case No.: U-22070
Exhibit No.: A-183 (HLP-61)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line	Description	U-21870 Approved
(a)	(b)	(c)
	Capital Spending	
1	New Business	347,888
2	Demand Failures	184,851
3	Asset Relocations	90,393
4	**Total Capital Spending**	$ 623,132

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Asset and Amortization Expense of the
Storm Deferral
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-184 (HLP-62)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) 2025	(d) 2026	(e) 2027	(f) 2028	(g) 2029	(h) 2030
1	Storm Deferral Regulatory Assetl[1]	SAP Account 1757500	51,997					
2	Amortization expense	Line 1, col. (c) / 36 months (amortization beginning in May 2027)	-	-	11,555	17,332	17,332	5,777
			12 Months Ending 4/30/2027	**12 Months Ending 4/30/2028**				
3	Test year Storm Deferral amortization expense	Line 2, col. (e) + (Line 2, col. (f)) ÷ 12 * 4)	**-**	17,332				

Notes

1 The Company received approval in case U-21914 to defer the extraordinary storm expenses of March/April 2025 as a Regulatory Asset. Refer to the testimony of Company witness Jeffery Dickey for a description of the deferred balances and testimony addressing the filing requirements outlined in Case No. U-21914.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Liability and Amortization Expense of
Case No. U-21502 (Itron Refund)
For the Projected 12-Month Period Ending April 30, 2028
($000)

Case No.: U-22070
Exhibit No.: A-185 (HLP-63)
Page: 1 of 1
Witness: HLPatton
Date: June 2026

Line No.	(a) Description	(b) Source	(c) 2025	(d) 2026	(e) 2027	(f) 2028
1	Customer Refund - ITRON	SAP Accounts 2467000	(3,000)	(3,000)		
2	Amortization expense	Line 1, col. (c) / 12 months (amortization beginning in May 2027	-	-	(2,000)	(1,000)
			12 Months Ending 4/30/2027	**12 Months Ending 4/30/2028**	**Average Balance 4/30/2028**	
3	Test year amortization expense {1}	See Note {1} below		(3,000)		
4	Customer Refund - ITRON Deferred Balance {1}	See Notes {1} and {2} below	(3,000)	-	(1,500)	

Notes

{1} In accordance with the settlement agreement approved in Case No. U-21502, the Company proposes to refund $3 million to customers through an offset to base rates
{2} (Line 4, col. (c) + line 4, col. (d)) ÷ 2

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBIT

OF

DANIEL A. SCHMOEKEL

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

Schedule B-5.10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of 5yr Historical and Projected Capital Expenditures
Streetlight Capital Expenditures
($000)

Case No.: U-22070
Exhibit No.: A-12 (DAS-1)
Schedule: B-5.10
Page: 1 of 4
Witness: DASchmoekel
Date: June 2026

Line No.	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2021	(c) Historical Year 12 Mos Ended 12/31/2022	(d) Historical Year 12 Mos Ended 12/31/2023	(e) Historical Year 12 Mos Ended 12/31/2024	(f) Historical Year 12 Mos Ended 12/31/2025	(g) Projected Bridge Year 12 Mos Ending 12/31/2026	(h) Projected Bridge Year 4 Mos Ending 4/30/2027	(i) Projected Bridge Year 16 Mos Ending 4/30/2027	(j) Projected Test Year 12 Mos Ending 4/30/2028
1	New Business	$ 2,320	$ 2,799	$ 2,524	$ 5,178	$ 4,553	$ 3,575	$ 1,222	$ 4,797	$ 3,692
2	Vicinity Upgrade	1,023	882	412	236	1,202	1,000	342	1,342	1,033
3	Streetlight Failures	12,210	11,220	8,769	13,127	17,548	16,401	5,604	22,005	16,935
4	**Total**	**$ 15,553**	**$ 14,901**	**$ 11,705**	**$ 18,541**	**$ 23,303**	**$ 20,977**	**$ 7,167**	**$ 28,144**	**$ 21,659**

Notes:

5 5-year average for demand failures and new business escalated by 2.9% for 2026

6 5-year average for demand failures and new business escalated by 2.5% for 2027

7 5-year average for demand failures and new business escalated by 0.7% (4-month prorated) for 2028

Line No.	(a) Description	(b) Projected 4 Mos Ending 4/30/2026	(c) Projected 12 Mos Ending 4/30/2027	(d) Projected 12 Mos Ending 4/30/2028	(e) Projected 28 Mos Ending 4/30/2028
8	New Business	$ 1,192	$ 3,605	$ 3,692	$ 8,489
9	Vicinity Upgrade	333	1,008	1,033	2,374
10	Streetlight Failures	5,467	16,538	16,935	38,940
11	**Total**	**$ 6,992**	**$ 21,152**	**$ 21,659**	**$ 49,803**

Schedule B-5.10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of 5yr Historical and Projected Capital Expenditures
Streetlight Unit Costs
($000)

Case No.: U-22070
Exhibit No.: A-12 (DAS-1)
Schedule: B-5.10
Page: 2 of 4
Witness: DASchmoekel
Date: June 2026

Line No.	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2021	(c) Historical Year 12 Mos Ended 12/31/2022	(d) Historical Year 12 Mos Ended 12/31/2023	(e) Historical Year 12 Mos Ended 12/31/2024	(f) Historical Year 12 Mos Ended 12/31/2025	(g) Projected Bridge Year 12 Mos Ending 12/31/2026	(h) Projected Bridge Year 4 Mos Ending 4/30/2027	(i) Projected Bridge Year 16 Mos Ending 4/30/2027	(j) Projected Test Year 12 Mos Ending 4/30/2028
1	New Business Units	188	242	195	205	238	214	71	285	214
2	New Business Unit Cost	$ 12,339	$ 11,565	$ 12,945	$ 25,259	$ 19,129	$ 16,739	$ 17,158	$ 16,844	$ 17,283
3	Vicinity Upgrade Units	183	1,807	783	478	2,643	1,360	453	1,813	1,360
4	Vicinity Upgrade Unit Cost	$ 5,590	$ 488	$ 526	$ 493	$ 455	$ 735	$ 754	$ 740	$ 759
5	Streetlight Failures Units	15,775	16,407	11,974	21,205	19,038	20,632	6,877	27,509	20,632
6	Streetlight Failures Unit Costs	$ 774	$ 684	$ 732	$ 619	$ 922	$ 795	$ 272	$ 800	$ 821
7	**Total Streetlight Units**	**16,146**	**18,456**	**12,952**	**21,888**	**21,919**	**22,205**	**7,402**	**29,607**	**22,205**
8	**Total Streetlight Unit Cost**	**$ 18,703**	**$ 12,737**	**$ 14,204**	**$ 26,371**	**$ 20,506**	**$ 18,269**	**$ 18,183**	**$ 18,384**	**$ 18,863**

Line No.	(a) Description	(b) Projected 4 Mos Ending 4/30/2026	(c) Projected 12 Mos Ending 4/30/2027	(d) Projected 12 Mos Ending 4/30/2028	(e) Projected 28 Mos Ending 4/30/2028
9	New Business Units	71	214	214	498
10	New Business Unit Cost	$ 16,739	$ 16,879	$ 17,283	$ 17,032
11	Vicinity Upgrade Units	453	1,360	1,360	3,173
12	Vicinity Upgrade Unit Cost	$ 735	$ 741	$ 759	$ 748
13	Streetlight Failures Units	6,877	20,632	20,632	48,141
14	Streetlight Failures Unit Costs	$ 795	$ 802	$ 821	$ 809
15	**Total Streetlight Units**	**7,402**	**22,205**	**22,205**	**51,812**
16	**Total Streetlight Unit Cost**	**$ 18,269**	**$ 18,422**	**$ 18,863**	**$ 18,589**

Schedule B-5.10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
Streetlight Capital Expenditures
($000's)

Case No.: U-22070
Exhibit No.: A-12 (DAS-1)
Schedule: B-5.10
Page: 3 of 4
Witness: DASchmoekel
Date: June 2026

Line No.	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2025	(c) Projected Bridge Period 12 Mos Ending 12/31/2026	(d) Projected Bridge Period 4 Mos Ending 4/30/2027	(e) Projected Bridge Period 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
1	**New Business**	**$ 4,553**	**$ 3,575**	**$ 1,222**	**$ 4,797**	**$ 3,692**
2	Labor	772	606	207	813	626
3	Capitalized E&S	875	687	235	922	710
4	Materials	1,412	1,109	379	1,488	1,145
5	Contractor	1,157	909	310	1,219	938
6	Non-Labor Overhead	208	163	56	219	168
7	Non-Labor Other	129	101	35	136	105
8	Contingency	-	-	-	-	-
9	**Vicinity Upgrade**	**$ 1,202**	**$ 1,000**	**$ 342**	**$ 1,342**	**$ 1,033**
10	Labor	159	133	45	178	137
11	Capitalized E&S	132	110	37	147	113
12	Materials	649	540	184	724	557
13	Contractor	122	102	35	137	105
14	Non-Labor Overhead	32	27	9	36	28
15	Non-Labor Other	107	89	31	120	92
16	Contingency	-	-	-	-	-
17	**Streetlight Failures**	**$ 17,548**	**$ 16,401**	**$ 5,604**	**$ 22,005**	**$ 16,935**
18	Labor	2,099	1,962	670	2,632	2,026
19	Capitalized E&S	2,951	2,758	942	3,701	2,848
20	Materials	7,419	6,934	2,369	9,304	7,160
21	Contractor	2,434	2,275	777	3,053	2,349
22	Non-Labor Overhead	634	592	202	795	612
23	Non-Labor Other	2,010	1,879	642	2,521	1,940
24	Contingency	-	-	-	-	-
25	**Total Streetlighting**	**$ 23,303**	**$ 20,977**	**$ 7,167**	**$ 28,144**	**$ 21,659**
26	Labor	3,030	2,700	923	3,623	2,788
27	Capitalized E&S	3,958	3,555	1,215	4,770	3,671
28	Materials	9,481	8,583	2,933	11,516	8,863
29	Contractor	3,714	3,286	1,123	4,408	3,393
30	Non-Labor Overhead	874	782	267	1,049	808
31	Non-Labor Other	2,247	2,070	707	2,777	2,137
32	Contingency	-	-	-	-	-

Schedule B-5.10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
Streetlight Capital Expenditures
($000's)

Case No.: U-22070
Exhibit No.: A-12 (DAS-1)
Schedule: B-5.10
Page: 4 of 4
Witness: DASchmoekel
Date: June 2026

Line No.	(a) Description	(b) 4 Mos Ending 4/30/2026	(c) 12 Mos Ending 4/30/2027	(d) 12 Mos Ending 4/30/2028	(e) 28 Mos Ending 4/30/2028
			Projected		
33	**New Business**	**$ 1,192**	**$ 3,605**	**$ 3,692**	**$ 8,489**
34	Labor	202	611	626	1,439
35	Capitalized E&S	229	693	710	1,632
36	Materials	370	1,118	1,145	2,633
37	Contractor	303	916	938	2,157
38	Non-Labor Overhead	54	164	168	387
39	Non-Labor Other	34	102	105	241
40	Contingency	-	-	-	-
41	**Vicinity Upgrade**	**$ 333**	**$ 1,008**	**$ 1,033**	**$ 2,374**
42	Labor	44	134	137	315
43	Capitalized E&S	37	110	113	260
44	Materials	180	544	557	1,282
45	Contractor	34	103	105	242
46	Non-Labor Overhead	9	27	28	64
47	Non-Labor Other	30	90	92	212
48	Contingency	-	-	-	-
49	**Streetlight Failures**	**$ 5,467**	**$ 16,538**	**$ 16,935**	**$ 38,940**
50	Labor	654	1,978	2,026	4,658
51	Capitalized E&S	919	2,781	2,848	6,549
52	Materials	2,311	6,992	7,160	16,464
53	Contractor	758	2,294	2,349	5,402
54	Non-Labor Overhead	197	597	612	1,406
55	Non-Labor Other	626	1,895	1,940	4,461
56	Contingency	-	-	-	-
57	**Total Streetlighting**	**$ 6,992**	**$ 21,152**	**$ 21,659**	**$ 49,803**
58	Labor	900	2,723	2,788	6,411
59	Capitalized E&S	1,185	3,585	3,671	8,441
60	Materials	2,861	8,655	8,863	20,379
61	Contractor	1,095	3,313	3,393	7,801
62	Non-Labor Overhead	261	789	808	1,857
63	Non-Labor Other	690	2,087	2,137	4,914
64	Contingency	-	-	-	-

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

SARA E. STEWART

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Line Clearing O&M Expense
2021-2025 Historical and 2026-2031 Projected

Case No.: U-22070
Exhibit No.: A-186 (SES-1)
Page: 1 of 1
Witness: SEStewart
Date: June 2026

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	Electric System	Expense Type	Year	2021	2022	2023	2024	2025	2026 Calendar Year	2027 Calendar Year	2028 Calendar Year	2029 Calendar Year	2030 Calendar Year	2031 Calendar Year	Total O&M Expense Test Period 5/1/27-4/30/28
				Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected	Projected
2	**Electric HVD**			**$10,739,347**	**$10,987,343**	**$11,301,449**	**$10,729,853**	**$9,673,037**	**$12,043,752**	**$11,454,391**	**$11,366,734**	**$10,363,213**	**$11,732,294**	**$11,708,134**	**$11,425,172**
3		Contractor	Maintenance Clearing	$4,488,246	$5,157,938	$4,775,712	$4,010,456	$4,224,374	$4,915,054	$4,838,099	$4,898,865	$4,368,402	$4,999,906	$4,976,424	$4,858,354
4		Contractor	Brushing - Cut	$2,797,068	$3,063,144	$3,601,378	$3,704,716	$2,748,268	$3,497,661	$3,052,100	$2,878,942	$2,332,623	$2,947,206	$2,920,294	$2,994,381
5		Contractor	Brushing - Spray	$2,407,477	$1,565,658	$1,885,968	$2,033,114	$1,514,331	$2,400,000	$2,400,000	$2,400,000	$2,448,000	$2,546,899	$2,546,899	$2,400,000
6		Contractor	Demand Clearing	$98,417	$89,478	$41,202	$42,841	$108,394	$60,000	$60,000	$60,000	$61,200	$62,424	$63,672	$60,000
7		Contractor	Noxious Weed Control	$95,891	$152,737	$82,545	$87,750	$79,177	$95,000	N/A	N/A	N/A	N/A	N/A	N/A
8		Contractor	HVD Contract Planning	Note[1]	$175,749	$294,503	$320,353	$407,814	$408,000	$416,160	$424,483	$432,973	$441,632	$450,465	$418,934
9		Labor	HVD Salaries	$751,684	$653,623	$516,139	$452,901	$533,295	$552,037	$564,182	$576,594	$592,165	$606,377	$619,717	$568,319
10		Other	HVD Expenses	$100,564	$129,016	$104,003	$77,722	$57,385	$116,000	$123,850	$127,850	$127,850	$127,850	$130,663	$125,183
11			**Miles**	**1,178**	**1,106**	**1,153**	**1,203**	**1,059**	**1,182**	**1,162**	**1,146**	**1,070**	**1,195**	**1,164**	**1,157**
12	**Electric LVD**			**$75,827,808**	**$91,016,131**	**$97,792,024**	**$99,494,748**	**$125,503,151**	**$152,966,707**	**$201,845,786**	**$228,149,213**	**$233,145,437**	**$240,127,560**	**$191,994,274**	**$210,613,595**
13		Contractor	Full-circuit Clearing	$62,121,855	$76,623,355	$84,128,930	$84,437,501	$107,437,042[1]	$135,674,820	$181,625,523	$207,236,888	$212,620,268	$218,980,016	$172,305,195	$190,162,644
14		Contractor	Repetitive Outage Zone	$1,711,666	$2,086,904	$1,542,258	$1,187,069	$1,379,358	$1,057,600	$1,114,969	$1,000,000	$900,000	$900,000	$900,000	$1,076,646
15		Contractor	CEMI Clearing	$491,257	$506,985	$306,882	$111,203	$425,765	$500,000	$600,000	$550,000	$450,000	$475,000	$500,000	$583,333
16		Contractor	First Zone Clearing	$405,771	$466,566	$492,077	$806,271	$1,841,513	$1,000,000	$900,000	$800,000	$700,000	$725,000	$750,000	$866,667
17		Contractor	LCP Zonal Clearing	N/A	N/A	N/A	$1,049,717	$1,361,823	$800,000	$589,814	$500,000	$450,000	$475,000	$500,000	$559,876
18		Contractor	Demand Clearing	$3,329,375	$2,737,654	$2,058,822	$2,235,640	$1,869,109	$2,250,000	$1,800,000	$1,525,610	$1,219,269	$1,218,654	$1,219,527	$1,708,537
19		Contractor	Brushing - Spray	$3,072,427	$3,302,319	$3,396,227	$3,491,649	$3,705,527	$3,500,000	$4,000,000	$4,500,000	$4,500,000	$4,750,000	$5,000,000	$4,166,667
20		Contractor	Distribution Contract Planning/Supervisior	Note[2]	$1,300,689	$2,274,692	$2,708,070	$3,555,279	$2,662,200	$4,555,847	$5,139,355	$5,242,143	$5,346,985	$3,516,228	$4,750,350
21		Labor	Distribution Salaries	$3,994,189	$3,120,678	$2,877,300	$2,809,333	$3,146,906	$4,279,163	$5,091,405	$5,218,690	$5,333,502	$5,450,839	$5,649,257	$5,133,834
22		Other	Distribution Expenses	$701,269	$870,981	$714,837	$658,295	$780,829	$1,242,924	$1,568,227	$1,678,669	$1,730,256	$1,806,066	$1,654,067	$1,605,041
23			*LVD Full-circuit Miles*	4,647	5,653	5,758	5,400	6,092[1]	7,891	10,889	12,829	13,573	14,834	12,337	11,535
24			*LVD Subprogram Clearing Miles*	238	247	165	209	252	199	174	149	125	125	127	166
25			*LVD Subprogram Spray Miles*	395	488	443	421	445	405	454	501	491	508	524	470
26			**LVD O&M Miles Total**	**5,279**	**6,388**	**6,365**	**6,030**	**6,790**	**8,496**	**11,517**	**13,479**	**14,188**	**15,467**	**12,989**	**12,171**
27	**Electric Total**		**O&M Expense**	**$86,567,155**	**$102,003,474**	**$109,093,473**	**$110,224,601**	**$135,176,188**	**$165,010,459**	**$213,300,177**	**$239,515,947**	**$243,508,650**	**$251,859,855**	**$203,702,409**	**$222,038,767**
28		Contractor	Clearing	$75,539,544	$90,884,760	$97,029,806	$97,673,165	$121,474,822	$149,850,135	$194,580,505	$219,450,305	$223,101,762	$230,783,206	$184,135,113	$202,870,438
29		Contractor	Brushing - Spray	$5,479,904	$4,867,977	$5,282,195	$5,524,763	$5,219,858	$5,900,000	$6,400,000	$6,900,000	$6,948,000	$7,296,899	$7,546,899	$6,566,667
30		Contractor	Contract Planning	Note[2], Note[3]	$1,476,438	$2,569,195	$3,028,422	$3,963,093	$3,070,200	$4,972,007	$5,563,839	$5,675,115	$5,788,618	$3,966,693	$5,169,284
31		Labor	Salaries	$4,745,873	$3,774,301	$3,393,439	$3,262,235	$3,680,201	$4,831,200	$5,655,587	$5,795,284	$5,925,667	$6,057,216	$6,268,974	$5,702,153
32		Other	Expenses	$801,833	$999,997	$818,840	$736,017	$838,214	$1,358,924	$1,692,077	$1,806,519	$1,858,106	$1,933,916	$1,784,730	$1,730,225
33		Other	Baseline O&M Expense						$150,600,325	$166,638,479	$169,971,248	$173,370,673	$176,838,087	$180,374,848	$167,749,402
34		Other	Ramp-Up Funding						$14,410,134	$46,661,698	$69,544,698	$70,137,977	$75,021,768	$23,327,560	$54,289,365
35		Other	Credit to Regulatory Asset						($14,410,134)	($46,661,698)	($69,544,698)	($70,137,977)	($75,021,768)	($23,327,560)	($54,289,365)
36			**O&M Miles**	**6,457**	**7,494**	**7,518**	**7,233**	**7,848**	**9,678**	**12,679**	**14,625**	**15,258**	**16,662**	**14,153**	**13,328**
37			HVD Cost/Mile	$9,117	$9,932	$9,801	$8,919	$9,135	$10,189	$9,857	$9,919	$9,690	$9,821	$10,059	$9,878
38			LVD Cost/Mile	$14,363	$14,248	$15,364	$16,500	$18,485	$18,005	$17,526	$16,926	$16,432	$15,525	$14,782	$17,304

Note[1]: Includes Wildfire Risk Mitigation expenditure and miles
Note[2]: HVD Contract Planners were not recorded separately in 2020-2021
Note[3]: LVD Contract Planners were not recorded separately in 2017-2021

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Projected LVD Tree-Caused[1] Reliability of the Line Clearing Ramp-Up Plan

Case No.: U-22070
Exhibit No.: A-187 (SES-2)
Page: 1 of 1
Witness: SEStewart
Date: June 2026

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Calendar Year**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
2	Actual Line Clearing Program Funding Level ($M)	86.567	102.003	109.093	110.224	135.176[2]						
3	Projected Line Clearing Program Funding Level ($M)						165.010	213.300	239.516	243.509	251.860	203.702
	Excluding MED, All Areas of Fault Including Secondary/Service Outages											
4	Actual Tree-Caused Outage Incidents	15,442	12,080	12,323	13,631	13,040						
5	Actual Tree-Caused SAIFI	0.3654	0.3061	0.3103	0.3232	0.2935						
6	Actual Tree-Caused SAIDI (minutes)	98.01	67.58	66.08	67.28	63.45						
	Excluding MED, Primary and Circuit Outages Only											
7	Actual Tree-Caused Outage Incidents	7,537	5,757	5,594	6,634	6,384						
8	Actual Tree-Caused SAIFI	0.3468	0.2952	0.2997	0.3118	0.2829						
9	Actual Tree-Caused SAIDI (minutes)	92.54	64.46	62.37	64.40	60.40						
10	Projected Tree-Caused Outage Incidents						5,801	5,687	5,471	5,162	4,626	4,373
11	Projected Tree-Caused SAIFI						0.3056	0.3003	0.2902	0.2758	0.2510	0.2395
12	Projected Tree-Caused SAIDI (minutes)						68.46	67.26	65.00	61.78	56.22	53.65
	Including MED, All Areas of Fault Including Secondary/Service Outages											
13	Actual Tree-Caused Outage Incidents	24,084	16,992	18,228	20,259	20,824						
14	Actual Tree-Caused SAIFI	0.6765	0.4855	0.5334	0.5524	0.5456						
15	Actual Tree-Caused SAIDI (minutes)	519.03	235.65	471.07	267.80	378.14						
	Including MED, Primary and Circuit Outages Only											
16	Actual Tree-Caused Outage Incidents	12,665	8,226	8,489	10,202	10,773						
17	Actual Tree-Caused SAIFI	0.6466	0.4709	0.5180	0.5361	0.5298						
18	Actual Tree-Caused SAIDI (minutes)	495.48	228.02	457.68	259.28	365.67						
19	Projected Tree-Caused Outage Incidents						9,106	8,862	8,450	7,897	7,004	6,605
20	Projected Tree-Caused SAIFI						0.5348	0.5220	0.5006	0.4719	0.4259	0.4058
21	Projected Tree-Caused SAIDI (minutes)						357.41	348.48	333.53	313.59	281.52	267.48

[1] Includes outages with cause codes Trees and Trees - Outside ROW

[2] Includes funding authorized in Case No. U-21585 for additional line clearing for wildfire risk mitigation

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2026 HVD Line Clearing Work Plan

Case No.: U-22070
Exhibit No.: A-188 (SES-3)
Page: 1 of 1
Witness: SEStewart
Date: June 2026

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Line Name	Miles	Voltage	Year Last Cleared	Line Name	Miles	Voltage	Year Last Cleared
1	AC - DELANEY	1.47	46	2022	HOMESTEAD	38.37	46	2022
2	ALLEGAN	12.77	46	2022	HOOKER	0.254	46	2022
3	ALLIANCE	1.25	138	2022	HOWARD CITY	27.11	46	2022
4	AMBER-LAKE WINDS	5.5	138	2022	INGERSOLL	18.16	46	2022
5	ASYLUM	0.19	46	2022	IOSCO - KARN	3.99	138	2022
6	ATHERTON	1.53	46	2022	JACKMAN	17.47	46	2022
7	ATTWOOD	13.95	46	2022	JANES	8.94	46	2022
8	ATWATER	15.62	46	2022	JOPPA	6.71	46	2022
9	ATWOOD	0.04	46	2022	KELVINATOR	6.59	46	2022
10	AUGUSTA	0.84	46	2024	KENT CO COGEN	0.58	46	2022
11	AUSABLE	0.7	138	2022	LASALLE	16.6	46	2022
12	BALZER	12.34	46	2022	LEE ST	7.44	46	2022
13	BARTON LAKE-BATAVIA	3.45	138	2022	LEONARD	2.76	46	2022
14	BEERS	2.13	46	2022	LINDEN	3.71	46	2022
15	BELDING	6.7	138	2022	LUCAS SOLAR TAP	0.6	46	2022
16	BISHOP	4.47	46	2022	MASON	21.47	46	2022
17	BLENDON-FOUR MILE	0.12	138	2022	MENASHA	5.13	46	2022
18	BOSTON SQUARE	2.76	46	2022	MERRILL	29.42	46	2022
19	BOWEN	2.57	46	2022	MILLER RD	14.73	46	2022
20	BREEDSVILLE	22.05	46	2022	MONTAGUE	10.48	46	2022
21	BRETON	6.23	46	2022	MONTROSE	26.52	46	2022
22	BRIDGEPORT	22.64	46	2022	NEW HAVEN	15.2	46	2022
23	BURDETT	11.29	46	2022	NORTH KENT	0.04	46	2022
24	BURROWS	8.48	46	2022	OAKWOOD	6	46	2022
25	CALKINS	14.61	46	2022	ORIOLE	0.02	46	2022
26	CANNONSBURG	20.77	46	2022	ORLEANS	13.96	46	2022
27	CARDINAL SOLAR	0.26	46	2022	OSHTEMO	8.59	46	2022
28	CARSON CITY	40.57	46	2022	PENTWATER	21.64	46	2022
29	CASCADE	3.43	46	2022	PHILLIPS #1	1.49	46	2022
30	CHEVROLET #4	2.8	46	2022	PHILLIPS #2	4.08	46	2022
31	COLDBROOK	1.83	46	2022	PIERSON	37.301	46	2022
32	CONWAY	32.96	46	2022	PLAINWELL	4.89	46	2022
33	COOPER	17	46	2022	QUINCY	13.43	46	2022
34	COURT #1	8.72	46	2022	RED ARROW	0.3	46	2022
35	COURT #2	5.51	46	2022	RIFLE RIVER - GALLAGHEF	5.38	138	2022
36	COURT ST TIE	1.02	46	2022	RIGA	35.25	46	2022
37	DEWEY	2.9	46	2022	RIVERDALE	27.59	46	2022
38	DIESEL	2.15	46	2022	ROCKFORD	11.82	46	2022
39	DOEHLER JARVIS	4.89	46	2022	SANTIAGO	7.5	138	2024
40	DONTZ RD	10.85	46	2022	SEIGLER	0.02	46	2022
41	EASTWOOD	6.83	46	2022	SIEGLER	3.83	46	2022
42	ERIE	11.72	46	2022	SONOMA	0.51	46	2022
43	FAIRBANKS	0.1	46	2022	SONOMA - BARNUM CREE	0.02	138	2022
44	FAIRFIELD	30.07	46	2022	SPAULDING - BEALS RD	1.81	138	2022
45	FENTON	13.13	46	2022	SQUIRES	27.58	46	2022
46	FITZNER	2.05	138	2022	STADIUM	2.78	46	2022
47	FRAME PLANT	2.37	46	2022	STANDISH	38.62	46	2022
48	GAINES - BRADLEY	0.03	138	2022	STANTON	13.4	46	2022
49	GALESBURG	14.54	46	2022	STERNS RD	4.3	46	2022
50	GALLAGHER	7.85	138	2022	THOMAS	11.77	46	2022
51	GMI	10.37	23	2022	THORNAPPLE	4.7	46	2022
52	GRAND LEDGE	27.72	46	2022	UNION CITY	50.02	46	2022
53	GREENVILLE	11.36	46	2022	UPTON	9.36	46	2022
54	GRODI RD	0.02	46	2022	VAN SLYKE #1	4.44	46	2022
55	GROVER	0.03	46	2022	VAN SLYKE #2	0.51	46	2022
56	HARBISON	5.29	46	2022	VERGENNES	0.49	138	2022
57	HARPER RD	0.01	46	2022	WALKER	15.36	46	2022
58	HARVEY ST	0.02	46	2022	WASHINGTON - HYDROMA	0.15	46	2022
59	HARVEY ST #1	0.08	46	2022	WEALTHY	0.9	46	2022
60	HARVEY ST #2	0.06	46	2022	WENTWORTH	1.87	46	2022
61	HARVEY STREET #3	0.06	46	2022	WHITEHALL	18.39	46	2022
62	HASKELITE	3.51	46	2022	YORK	13.14	46	2022
63	Grand Total	1182.07						

Line No.	Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Feeder ID	Substation	Circuit	HQ	Voltage	Circuit Miles	Work Plan Miles	Circuit Customers	Average Outages per Incident	Years Since Last Cleared	Relative Risk Score (0-100)	3-Year Weighted Average Incidents per Mile	Customer Density per Mile	On Cycle Miles	Backlog Miles	Notes
1	000201	MT PLEASANT	COLLEGE	ALM	4.8/8.32 kV Wye Grounded	15.61	15.61	2173	0	5	4	0.000	139.2	15.61	0.00	
2	000301	WEST RIVER	GRAND RIVER	GRN	7.2/12.47 kV Wye Grounded	15.67	15.67	702	49.46	5	16	0.277	44.8	15.67	0.00	
3	000302	WEST RIVER	CHAMBERLIN	GRN	7.2/12.47 kV Wye Grounded	10.04	10.02	413	43.00	5	6	0.365	41.1	10.02	0.00	
4	002001	GREENWOOD	RAU ROAD	WBR	14.4/24.9 kV Wye Grounded	87.21	87.13	1062	157.38	13	57	0.161	12.2	0.00	87.13	
5	002402	BEAVERTON	TOBACCO	CLR	4.8/8.32 kV Wye Grounded	63.12	14.80	1255	44.22	16				0.00	14.80	Carryover
6	003001	FIVE CHANNELS HYDR	DISTRIBUTION	TWS	2.4 kV Delta	10.92	10.92	210	51.94	9	8	0.488	19.2	0.00	10.92	
7	004101	TAWAS	EAST TAWAS	TWS	4.8/8.32 kV Wye Grounded	3.64	3.67	362	0.00	38	18	0.000	99.5	0.00	3.67	
8	004601	BULLOCK	STEWART	MDL	4.8/8.32 kV Wye Grounded	56.71	56.71	1212	60.18	10	19	0.235	21.4	0.00	56.71	
9	004603	BULLOCK	PRAIRIE	MDL	4.8/8.32 kV Wye Grounded	15.20	15.20	433	45.33	5	9	0.263	28.5	15.20	0.00	
10	005501	AUBURN	ELEVATOR	BCY	4.8/8.32 kV Wye Grounded	25.15	25.15	1572	429.25	20	22	0.106	62.5	0.00	25.15	
11	006101	SAGINAW STREET	PAYNE STREET	FLT	4.8/8.32 kV Wye Grounded	0.54	0.54	104	0.00	38	18	0.000	192.6	0.00	0.54	
12	006102	SAGINAW STREET	BUCKHAM	FLT	4.8/8.32 kV Wye Grounded	1.30	1.30	3	0.00	38	18	0.000	2.3	0.00	1.30	
13	006103	SAGINAW STREET	E COMMERCIAL	FLT	4.8/8.32 kV Wye Grounded	0.63	0.63	5	0.00	38	18	0.000	7.9	0.00	0.63	
14	006104	SAGINAW STREET	HARRISON STREET	FLT	4.8/8.32 kV Wye Grounded	1.32	1.32	171	0.00	38	18	0.000	129.5	0.00	1.32	
15	006105	SAGINAW STREET	UNION INDUSTRIAL	FLT	4.8/8.32 kV Wye Grounded	0.46	0.46	2	0.00	38	18	0.000	4.3	0.00	0.46	
16	006106	SAGINAW STREET	BEACH STREET	FLT	4.8/8.32 kV Wye Grounded	1.22	1.22	26	0.00	38	18	0.000	21.3	0.00	1.22	
17	006107	SAGINAW STREET	LEWIS STREET	FLT	4.8/8.32 kV Wye Grounded	1.65	1.65	120	0.00	38	18	0.000	72.7	0.00	1.65	
18	006108	SAGINAW STREET	N DETROIT STREET	FLT	4.8/8.32 kV Wye Grounded	0.66	0.66	4	0.00	38	18	0.000	6.1	0.00	0.66	
19	007102	ERIE	PERE MARQUETTE	SMN	7.2/12.47 kV Wye Grounded	16.61	16.59	870	0.00	5	3	0.000	52.4	16.59	0.00	
20	007304	MILTON	MILLPOND	BIG	7.2/12.47 kV Wye Grounded	44.2	35.10	956	50.61	9				0.00	35.10	Carryover
21	008502	ELM STREET	VERONA	BCK	4.8/8.32 kV Wye Grounded	15.36	15.36	2378	715.29	5	42	0.152	154.8	15.36	0.00	
22	008505	ELM STREET	PORTER	BCK	4.8/8.32 kV Wye Grounded	15.95	15.95	1678	27.00	5	6	0.042	105.2	15.95	0.00	
23	009101	ESSEXVILLE	ESSEXVILLE	BCY	4.8/8.32 kV Wye Grounded	20.80	20.80	1669	14.00	29	15	0.016	80.2	0.00	20.80	
24	009102	ESSEXVILLE	WOODSIDE	BCY	4.8/8.32 kV Wye Grounded	7.71	7.71	617	30.00	10	5	0.086	80.0	0.00	7.71	
25	009103	ESSEXVILLE	CENTER ROAD	BCY	4.8/8.32 kV Wye Grounded	7.49	7.49	482	317.50	14	7	0.089	64.4	0.00	7.49	
26	009901	FREELAND	RURAL	SAG	4.8/8.32 kV Wye Grounded	41.61	41.61	1553	14.33	14	7	0.024	37.3	0.00	41.61	
27	009902	FREELAND	FREELAND	SAG	4.8/8.32 kV Wye Grounded	67.77	10.00	2192	296.60	16				0.00	10.00	Carryover
28	010401	GLADWIN	RURAL	CLR	4.8/8.32 kV Wye Grounded	61.75	61.75	1179	38.93	24	21	0.162	19.1	0.00	61.75	
29	011001	HASTINGS	BROADWAY	HST	4.8/8.32 kV Wye Grounded	31.44	31.44	1445	60.91	5	6	0.117	46.0	31.44	0.00	
30	011002	HASTINGS	HANOVER	HST	4.8/8.32 kV Wye Grounded	27.10	27.10	1573	47.18	11	12	0.271	58.0	0.00	27.10	
31	012001	LEELANAU	OMENA BAY	TRA	7.2/12.47 kV Wye Grounded	19.54	19.24	360	95.11	5	6	0.324	18.4	19.24	0.00	
32	012702	NEW RICHMOND	HOLLAND RENDERING	HML	4.8/8.32 kV Wye Grounded	0.25	0.25	3	0.00	32	15	0.000	12.0	0.00	0.25	
33	013402	TECUMSEH	EVANS STREET	ADR	7.2/12.47 kV Wye Grounded	14.00	14.00	1042	155.90	5	16	0.238	74.4	14.00	0.00	
34	014401	HANNAH	HANNAH	TRA	14.4/24.9 kV Wye Grounded	137.79	136.32	1779	136.32	17	21	0.060	12.9	0.00	136.32	
35	014801	MORENCI	CITY	ADR	7.2/12.47 kV Wye Grounded	15.24	15.24	860	97.20	5	11	0.109	56.4	15.24	0.00	
36	014802	MORENCI	MOREY	ADR	7.2/12.47 kV Wye Grounded	38.39	38.39	600	101.13	5	9	0.069	15.6	38.39	0.00	
37	015501	JEROME ROAD	STATE STREET	ALM	4.8/8.32 kV Wye Grounded	11.82	11.82	281	36.50	5	2	0.056	23.8	11.82	0.00	
38	016202	REED CITY	MEDICAL	BIG	4.8/8.32 kV Wye Grounded	5.28	5.28	539	0.00	6	3	0.000	102.1	0.00	5.28	
39	017006	HARVEY STREET	FULLER	GRA	7.2/12.47 kV Wye Grounded	8.76	8.76	2529	79.5	5	7	0.076	288.7	8.76	0.00	
40	017503	EAST GENESEE AVE	BAGLEY	SAG	4.8/8.32 kV Wye Grounded	7.89	7.89	635	0.00	5	5	0.000	80.5	7.89	0.00	
41	017603	WESTERN AVENUE	WEST BUSINESS	MUS	7.2/12.47 kV Wye Grounded	7.82	7.82	1064	72.67	5	3	0.128	136.1	7.82	0.00	
42	017701	PINCONNING	PINCONNING	BCY	4.8/8.32 kV Wye Grounded	28.64	28.64	598	46.88	6	12	0.279	20.9	0.00	28.64	
43	017702	PINCONNING	WHITE FEATHER	BCY	4.8/8.32 kV Wye Grounded	33.28	33.28	953	44.73	13				0.00	33.28	Carryover
44	018102	ATHERTON	GRAND TRAVERSE	FLT	4.8/8.32 kV Wye Grounded	0.84	0.84	15	0.00	38	18	0.000	17.9	0.00	0.84	
45	018501	PULLMAN	CHICORA	HML	4.8/8.32 kV Wye Grounded	63.71	30.00	1260	79.79	15				0.00	30.00	Carryover
46	018901	FINE LAKE	BRISTOL	BCK	4.8/8.32 kV Wye Grounded	69.57	69.57	826	36.98	17	24	0.273	11.9	0.00	69.57	
47	020104	EDMORE	BLANCHARD	ALM	11.0 kV Delta	0.03	0.03	0	0.00	5	12	0.000	0.0	0.03	0.00	
48	020901	ST HELEN	KENO	WBR	4.8/8.32 kV Wye Grounded	31.61	31.61	239	24	6	6	0.211	7.6	0.00	31.61	
49	020902	ST HELEN	ST HELEN	WBR	4.8/8.32 kV Wye Grounded	26.62	26.60	1477	33.75	5	4	0.100	55.5	26.60	0.00	
50	021201	PHILLIPS	ALCOTT	KAL	4.8/8.32 kV Wye Grounded	11.10	11.10	1343	235.5	5	14	0.300	121.0	11.10	0.00	
51	021202	PHILLIPS	FACTORY	KAL	4.8/8.32 kV Wye Grounded	7.21	7.21	1585	264.67	7	31	0.277	219.8	0.00	7.21	
52	021204	PHILLIPS	INKSTER	KAL	4.8/8.32 kV Wye Grounded	8.84	8.84	1246	23.67	5	8	0.113	141.0	8.84	0.00	

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	Feeder ID	Substation	Circuit	HQ	Voltage	Circuit Miles	Work Plan Miles	Circuit Customers	Average Outages per Incident	Years Since Last Cleared	Relative Risk Score (0-100)	3-Year Weighted Average Incidents per Mile	Customer Density per Mile	On Cycle Miles	Backlog Miles	Notes
53	021701	STATE STREET	MACKINAW	SAG	4.8/8.32 kV Wye Grounded	9.33	9.33	1526	559.5	5	10	0.071	163.6	9.33	0.00	
54	021703	STATE STREET	STATE STREET	SAG	4.8/8.32 kV Wye Grounded	9.65	9.65	1754	0.00	9	10	0.000	181.8	0.00	9.65	
55	021903	GOGUAC	RIVERSIDE	BCK	4.8/8.32 kV Wye Grounded	11.06	11.06	977	343.33	5	10	0.090	88.3	11.06	0.00	
56	022503	MIDDLETON	NEWARK	ALM	4.8/8.32 kV Wye Grounded	61.26	61.26	762	28.40	13				0.00	61.26	Carryover
57	022701	ALLENDALE	RIVER	MUS	4.8/8.32 kV Wye Grounded	41.80	35.00	1028	98.89	18				0.00	35.00	Carryover
58	023103	MENDON	M-60	CLD	14.4/24.9 kV Wye Grounded	69.48	69.48	853	52.86	5	10	0.067	12.3	69.48	0.00	
59	023401	NEFF ROAD	LEWIS ROAD	FLT	14.4/24.9 kV Wye Grounded	50.15	50.15	1425	74.65	25	30	0.153	28.4	0.00	50.15	
60	023402	NEFF ROAD	DODGE ROAD	FLT	14.4/24.9 kV Wye Grounded	48.07	38.00	1784	63.29	17				0.00	38.00	Carryover
61	023507	BEALS ROAD	DIVISION ROAD	GRA	7.2/12.47 kV Wye Grounded	7.21	7.21	1044	0.00	5	3	0.000	144.8	7.21	0.00	
62	023702	CASINO	LEATON	ALM	4.8/8.32 kV Wye Grounded	72.49	72.49	1476	50.63	5	14	0.110	20.4	72.49	0.00	
63	023801	LAKE MITCHELL	GOLF CLUB	CAD	4.8/8.32 kV Wye Grounded	78.57	78.57	1459	77.83	15	12	0.076	18.6	0.00	78.57	
64	024202	MCBAIN	VOGEL CENTER	CAD	14.4 kV Delta	133.30	133.30	1229	39.42	10	10	0.030	9.2	0.00	133.30	
65	025103	NORTH MUSKEGON	STATE PARK	MUS	7.2/12.47 kV Wye Grounded	30.17	6.00	1919	89.52	9				0.00	6.00	Carryover
66	025302	NASHVILLE	NASHVILLE	HST	4.8/8.32 kV Wye Grounded	94.57	94.57	1337	77.84	5	16	0.088	14.1	94.57	0.00	
67	025601	BRIDGEPORT	BRIDGEPORT	SAG	4.8/8.32 kV Wye Grounded	23.19	10.00	1452	112.33	10				0.00	10.00	Carryover
68	025701	OSHTEMO	ALMENA	KAL	4.8/8.32 kV Wye Grounded	39.36	25.00	1056	141.60	18				0.00	25.00	Carryover
69	025902	HANOVER	HORTON	JAC	4.8/8.32 kV Wye Grounded	57.00	57.00	681	57.59	11	23	0.240	11.9	0.00	57.00	
70	026402	NORTH LANSING	LABORATORY	LAN	4.8/8.32 kV Wye Grounded	14.05	14.05	612	62.6	12	8	0.119	43.6	0.00	14.05	
71	027402	CONKLIN PARK	CROTON	BIG	4.8/8.32 kV Wye Grounded	31.29	31.29	1049	194.66	5	30	0.373	33.5	31.29	0.00	
72	027902	HAGER PARK	HAGER PARK	GRA	7.2/12.47 kV Wye Grounded	60.81	60.81	4062	689.47	17				0.00	60.81	Carryover
73	028001	OTISVILLE	IRISH ROAD	FLT	4.8/8.32 kV Wye Grounded	76.51	44.00	1295	66.15	16				0.00	44.00	Carryover
74	028002	OTISVILLE	STATE ROAD	FLT	4.8/8.32 kV Wye Grounded	58.95	58.95	1058	23.04	5	13	0.130	17.9	58.95	0.00	
75	028201	HOMER	HOMER	CLD	4.8/8.32 kV Wye Grounded	54.41	25.00	767	30.42	11				0.00	25.00	Carryover
76	028303	CEDAR SPRINGS	WHITE CREEK	GRN	14.4/24.9 kV Wye Grounded	68.71	68.71	1601	285.43	5	12	0.102	23.3	68.71	0.00	
77	029301	MARKEY	MONTYVILLE	WBR	4.8/8.32 kV Wye Grounded	41.46	22.00	2431	269.00	12	11	0.113	58.6	0.00	22.00	
78	029401	KEARSLEY	CROSBY ROAD	FLT	4.8/8.32 kV Wye Grounded	15.11	15.11	1259	182	5	5	0.022	83.3	15.11	0.00	
79	029406	KEARSLEY	COVERT ROAD	FLT	4.8/8.32 kV Wye Grounded	9.13	9.13	1089	176.43	5	9	0.256	119.3	9.13	0.00	
80	029901	NORTON	PONTALUNA ROAD	MUS	7.2/12.47 kV Wye Grounded	30.91	30.91	1231	102.45	21	18	0.119	39.8	0.00	30.91	
81	030501	ORLEANS	LONG LAKE	GVL	4.8/8.32 kV Wye Grounded	46.77	36.30	828	102.06	15				0.00	36.30	Carryover
82	031102	LAMOREAUX	LAMOREAUX	GRN	7.2/12.47 kV Wye Grounded	10.70	10.70	743	104.43	10				0.00	10.70	Carryover
83	031701	ABERDEEN	RICKMAN	GRA	7.2/12.47 kV Wye Grounded	16.31	16.31	2497	368.67	5	21	0.061	153.1	16.31	0.00	
84	031801	EAST MUSKEGON	MILL IRON	MUS	7.2/12.47 kV Wye Grounded	17.91	17.91	944	49.75	5	5	0.149	52.7	17.91	0.00	
85	031803	EAST MUSKEGON	QUARTERLINE ROAD	MUS	7.2/12.47 kV Wye Grounded	9.01	9.01	1124	103.25	5	8	0.148	124.8	9.01	0.00	
86	032404	HOWARD CITY	CORAL	BIG	14.4/24.9 kV Wye Grounded	80.35	80.35	2078	110.48	9				0.00	80.35	Carryover
87	033101	VAN BUREN	VAN BUREN	GRA	7.2/12.47 kV Wye Grounded	26.42	26.42	1938	992.50	17				0.00	26.42	Carryover
88	033301	AU GRES	POINT LOOK-OUT	TWS	11.0 kV Delta	49.95	49.81	322	43.5	5	4	0.067	6.4	49.81	0.00	
89	033702	EAST GRANT	ONION FARMS	FRE	4.8/8.32 kV Wye Grounded	23.13	23.13	238	36.12	38	21	0.245	10.3	0.00	23.13	
90	033803	HARRISON	STOCKWELL	CLR	4.8/8.32 kV Wye Grounded	35.31	11.90	1676	70.52	9				0.00	11.90	Carryover
91	034002	DIMONDALE	DIMONDALE	LAN	4.8/8.32 kV Wye Grounded	31.68	31.68	1157	168.93	12	25	0.158	36.5	0.00	31.68	
92	034003	DIMONDALE	ROSSMAN	LAN	4.8/8.32 kV Wye Grounded	38.62	38.62	1092	71.19	20	33	0.276	28.3	0.00	38.62	
93	035002	FRUITPORT	JUDSON ROAD	MUS	7.2/12.47 kV Wye Grounded	39.19	39.19	1600	139.11	8	42	0.527	40.8	0.00	39.19	
94	036002	LIBERTY	HAMBLIN	BCK	4.8/8.32 kV Wye Grounded	9.09	9.09	623	225.25	5	4	0.147	68.5	9.09	0.00	
95	036004	LIBERTY	LIBERTY	BCK	4.8/8.32 kV Wye Grounded	4.57	4.57	436	220.00	5	3	0.073	95.4	4.57	0.00	
96	036804	APPLE	BROOKS ROAD	MUS	7.2/12.47 kV Wye Grounded	45.62	45.62	2413	120.47	25	39	0.343	52.9	0.00	45.62	
97	037601	BATTEESE	COON HILL	JAC	14.4/24.9 kV Wye Grounded	47.30	47.30	842	79.9	8	43	0.352	17.8	0.00	47.30	
98	037603	BATTEESE	MUNITH	JAC	14.4/24.9 kV Wye Grounded	102.03	102.03	1297	79.52	9	38	0.170	12.7	0.00	102.03	
99	037901	HESPERIA	HESPERIA	FRE	4.8/8.32 kV Wye Grounded	59.95	59.95	1271	45.42	5	12	0.106	21.2	59.95	0.00	
100	039301	NIAGARA	ADAMS	SAG	4.8/8.32 kV Wye Grounded	4.77	4.77	920	0.00	5	4	0.000	192.9	4.77	0.00	
101	039602	HOUGHTON HEIGHTS	PRUDENVILLE	WBR	14.4/24.9 kV Wye Grounded	98.94	98.55	3416	93	14	23	0.179	34.5	0.00	98.55	
102	040901	MERSON	MERSON	HML	4.8/8.32 kV Wye Grounded	60.14	60.14	1129	72.90	14	24	0.272	18.8	0.00	60.14	
103	040902	MERSON	DUCK LAKE	HML	4.8/8.32 kV Wye Grounded	52.30	52.30	597	74.98	5	41	0.363	11.4	52.30	0.00	
104	041104	KELLOGGSVILLE	MAJESTIC	GRA	7.2/12.47 kV Wye Grounded	15.18	15.18	2163	522	26				0.00	15.18	Carryover

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	Feeder ID	Substation	Circuit	HQ	Voltage	Circuit Miles	Work Plan Miles	Circuit Customers	Average Outages per Incident	Years Since Last Cleared	Relative Risk Score (0-100)	3-Year Weighted Average Incidents per Mile	Customer Density per Mile	On Cycle Miles	Backlog Miles	Notes
105	041602	WHITTUM	ROYSTON	LAN	4.8/8.32 kV Wye Grounded	51.79	15.00	611	79.82	16				0.00	15.00	Carryover
106	041702	GALESBURG	CHARLESTON	KAL	4.8/8.32 kV Wye Grounded	27.19	27.19	912	56.00	11	17	0.343	33.5	0.00	27.19	
107	041802	NORTH ADAMS	NORTH ADAMS	ADR	4.8/8.32 kV Wye Grounded	38.57	38.57	664	112.4	10				0.00	38.57	Carryover
108	041901	CONCORD	SWAINS LAKE	JAC	4.8/8.32 kV Wye Grounded	46.18	28.30	887	73.31	16				0.00	28.30	Carryover
109	042101	LAKE LEANN	BUNDY HILL	JAC	14.4/24.9 kV Wye Grounded	63.59	63.59	756	28.88	5	15	0.168	11.9	63.59	0.00	
110	042302	GERRISH	GOLF CLUB	WBR	14.4 kV Delta	36.45	36.40	734	231.08	5	3	0.110	20.1	36.40	0.00	
111	042501	KINDERHOOK	LAKE DRIVE	CLD	4.8/8.32 kV Wye Grounded	100.75	100.75	2012	65.36	5	29	0.093	20.0	100.75	0.00	
112	042502	KINDERHOOK	GILEAD	CLD	4.8/8.32 kV Wye Grounded	113.67	113.67	2172	82.80	7	41	0.088	19.1	0.00	113.67	
113	044201	MONTAGUE	DOWLING	MUS	7.2/12.47 kV Wye Grounded	24.47	24.47	1596	189.15	5	26	0.177	65.2	24.47	0.00	
114	045302	BRICKER	ELLIS	GVL	14.4/24.9 kV Wye Grounded	8.50	8.50	186	17.00	5	2	0.118	21.9	8.50	0.00	
115	048401	BAY HARBOR	DUNDEE	BNC	7.2/12.47 kV Wye Grounded	16.97	16.97	457	0.00	5	2	0.000	26.9	16.97	0.00	
116	048402	BAY HARBOR	PRESERVE	BNC	7.2/12.47 kV Wye Grounded	28.10	28.10	283	0.00	5	2	0.000	10.1	28.10	0.00	
117	048501	RODNEY	HORSE HEAD LAKE	BIG	14.4/24.9 kV Wye Grounded	48.57	48.57	739	54.86	5	11	0.192	15.2	48.57	0.00	
118	048602	MORGAN	ST MARYS	BCK	4.8/8.32 kV Wye Grounded	68.51	45.00	1341	104.14	7				0.00	45.00	Carryover
119	049903	STANDALE	VILLAGE	GRA	7.2/12.47 kV Wye Grounded	27.70	27.70	998	130.57	5	7	0.168	36.0	27.70	0.00	
120	051901	SAUGATUCK	DOUGLAS	HML	4.8/8.32 kV Wye Grounded	46.47	10.00	2260	102.16	13				0.00	10.00	Carryover
121	052303	WOOD STREET	CHIPPEWA	FLT	4.8/8.32 kV Wye Grounded	1.64	1.64	187	0.00	38	18	0.000	114.0	0.00	1.64	
122	053501	PRESCOTT	MAPLE RIDGE	WBR	11.0 kV Delta	67.97	67.96	571	149.73	5	9	0.108	8.4	67.96	0.00	
123	053602	ROSE CITY	COYOTES	WBR	4.8/8.32 kV Wye Grounded	120.08	100.56	2096	41.04	12				0.00	100.56	Carryover
124	053603	ROSE CITY	KLACKING CREEK	WBR	4.8/8.32 kV Wye Grounded	53.87	9.00	559	0.00	12				0.00	9.00	Carryover
125	054302	KINGSLEY	CENTER ROAD	TRA	4.8/8.32 kV Wye Grounded	83.47	82.70	1097	44.81	13	10	0.064	13.1	0.00	82.70	
126	054404	ORIOLE	BRYANT ROAD	LDG	14.4/24.9 kV Wye Grounded	46.89	46.89	1597	112.05	5	16	0.149	34.1	46.89	0.00	
127	054601	ALDEN	TORCH	TRA	7.2/12.47 kV Wye Grounded	42.67	42.36	1108	33.00	5	7	0.078	26.0	42.36	0.00	
128	055801	BELLAIRE	DOWNTOWN	TRA	7.2/12.47 kV Wye Grounded	22.27	21.97	1016	28.31	5	6	0.195	45.6	21.97	0.00	
129	056301	ROTHBURY	NEW ERA	MUS	7.2/12.47 kV Wye Grounded	33.18	33.18	615	64.74	13	16	0.191	18.5	0.00	33.18	
130	056801	RAMONA	ROBINSON	GRA	7.2/12.47 kV Wye Grounded	15.89	15.89	1792	102.3	5	21	0.210	112.8	15.89	0.00	
131	056803	RAMONA	REEDS LAKE	GRA	7.2/12.47 kV Wye Grounded	8.47	8.47	1213	0.00	5	15	0.000	143.2	8.47	0.00	
132	056903	NORTHPORT	OMENA	TRA	7.2/12.47 kV Wye Grounded	9.72	9.63	237	71.45	5	9	0.686	24.4	9.63	0.00	
133	057602	POTTERVILLE	M-78	LAN	4.8/8.32 kV Wye Grounded	83.40	83.40	1438	132.37	24	47	0.204	17.2	0.00	83.40	
134	057702	JANES	WALNUT	SAG	4.8/8.32 kV Wye Grounded	6.86	6.86	697	0.00	5	6	0.000	101.6	6.86	0.00	
135	057703	JANES	PERKINS STREET	SAG	4.8/8.32 kV Wye Grounded	7.39	7.39	804	0.00	5	5	0.000	108.8	7.39	0.00	
136	058001	GENESEEVILLE	GENESEE	FLT	4.8/8.32 kV Wye Grounded	27.76	27.76	1564	624.29	27	36	0.084	56.3	0.00	27.76	
137	058601	LEITH STREET	FRANKLIN	FLT	4.8/8.32 kV Wye Grounded	9.29	9.29	766	177	5	8	0.072	82.5	9.29	0.00	
138	058902	THORNAPPLE	BUTTRICK	GRE	4.8/8.32 kV Wye Grounded	32.44	32.44	1002	99.36	5	9	0.144	30.9	32.44	0.00	
139	058903	THORNAPPLE	RIX ST	GRE	4.8/8.32 kV Wye Grounded	10.23	10.23	511	41.60	5	4	0.163	50.0	10.23	0.00	
140	059502	ATHENS	ATHENS	BCK	4.8/8.32 kV Wye Grounded	41.70	41.70	666	137.88	5	13	0.136	16.0	41.70	0.00	
141	059902	HEMLOCK	HEMLOCK	SAG	4.8/8.32 kV Wye Grounded	53.54	37.00	1011	28.89	12				0.00	37.00	Carryover
142	060903	NAPOLEON	NORVELL	JAC	4.8/8.32 kV Wye Grounded	50.20	50.20	873	194.00	5	25	0.113	17.4	50.20	0.00	
143	061102	KENDALL	SAGE	KAL	4.8/8.32 kV Wye Grounded	15.88	5.00	2456	349.13	12				0.00	5.00	Carryover
144	063401	KILGORE	MILHAM	KAL	4.8/8.32 kV Wye Grounded	12.07	12.07	703	39.29	5	8	0.193	58.2	12.07	0.00	
145	063501	LEVEL PARK	COLLIER	BCK	4.8/8.32 kV Wye Grounded	47.99	47.99	1538	99.84	5	18	0.264	32.0	47.99	0.00	
146	063601	LAKE CITY	JENNINGS	CAD	14.4/24.9 kV Wye Grounded	91.43	91.43	2416	42.92	5	6	0.091	26.4	91.43	0.00	
147	063702	PLAINFIELD	BELMONT	GRN	4.8/8.32 kV Wye Grounded	20.85	20.85	1311	134.64	11				0.00	20.85	Carryover
148	066301	LEHRING	COLE ROAD	OWS	4.8/8.32 kV Wye Grounded	58.07	58.07	722	58.08	14	16	0.149	12.4	0.00	58.07	
149	066902	BAUM STREET	SAGINAW NEWS/FEDER	SAG	4.8/8.32 kV Wye Grounded	1.83	1.83	15	0	38	18	0.000	8.2	0.00	1.83	
150	066903	BAUM STREET	AT AND T	SAG	4.8/8.32 kV Wye Grounded	0.28	0.28	0	0	38	18	0.000	0.0	0.00	0.28	
151	066904	BAUM STREET	CENTRAL BUSINESS/ME	SAG	4.8/8.32 kV Wye Grounded	1.97	1.97	62	0.00	16	7	0.000	31.5	0.00	1.97	
152	066905	BAUM STREET	CITY RAMP/MET (TEMP)/	SAG	4.8/8.32 kV Wye Grounded	1.99	1.99	99	0.00	16	7	0.000	49.7	0.00	1.99	
153	067503	MCCRACKEN	LEON	MUS	7.2/12.47 kV Wye Grounded	9.43	9.43	830	147.78	5	13	0.318	88.0	9.43	0.00	
154	067602	MCGRAW	CASS	BCY	4.8/8.32 kV Wye Grounded	10.69	10.69	366	14.5	5	3	0.187	34.2	10.69	0.00	
155	068303	MACKINAW CITY	BAYWIND GENERATION	BNC	14.4/24.9 kV Wye Grounded	1.25	1.25	0	0.00	5	2	0.000	0.0	1.25	0.00	
156	068601	PARKWAY	DUTTON	KAL	4.8/8.32 kV Wye Grounded	0.31	0.31	4	0	28	13	0.000	12.9	0.00	0.31	

Line No.	Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Feeder ID	Substation	Circuit	HQ	Voltage	Circuit Miles	Work Plan Miles	Circuit Customers	Average Outages per Incident	Years Since Last Cleared	Relative Risk Score (0-100)	3-Year Weighted Average Incidents per Mile	Customer Density per Mile	On Cycle Miles	Backlog Miles	Notes
157	068602	PARKWAY	BALCH	KAL	4.8/8.32 kV Wye Grounded	1.81	1.81	113	33.00	6	3	0.184	62.4	0.00	1.81	
158	068603	PARKWAY	VINE	KAL	4.8/8.32 kV Wye Grounded	8.40	8.40	2062	746.00	6	37	0.198	245.5	0.00	8.40	
159	068604	PARKWAY	SOUTH CENTRAL	KAL	4.8/8.32 kV Wye Grounded	6.33	6.33	914	66.67	9	9	0.158	144.4	0.00	6.33	
160	069102	UNIVERSITY	HARRISON	LAN	4.8/8.32 kV Wye Grounded	6.64	6.64	540	137.33	5	6	0.151	81.3	6.64	0.00	
161	069902	WALKER	ROSALIE	GRA	7.2/12.47 kV Wye Grounded	28.56	28.56	3022	136.18	5	11	0.128	105.8	28.56	0.00	
162	070004	DEAN ROAD	PARSHALLVILLE	FLT	14.4/24.9 kV Wye Grounded	55.23	55.23	985	90.70	5	17	0.121	17.8	55.23	0.00	
163	070104	WALNUT	GILKEY	FLT	4.8/8.32 kV Wye Grounded	9.60	9.60	1153	73.50	20	17	0.069	120.1	0.00	9.60	
164	070301	INGHAM	JACKSON STREET/PORT	JAC	4.8 kV Delta	1.91	1.91	100	0	38	27	0.000	52.4	0.00	1.91	
165	070302	INGHAM	HAYES ALLEY/CONSUMI	JAC	4.8 kV Delta	0.73	0.73	7	0.00	38	27	0.000	9.6	0.00	0.73	
166	070303	INGHAM	JACKSON SQUARE	JAC	4.8/8.32 kV Wye Grounded	1.63	1.63	127	0.00	37	17	0.000	77.9	0.00	1.63	
167	072301	BARNARD	HOSPITAL	SAG	4.8/8.32 kV Wye Grounded	5.10	5.10	867	0	6	4	0.000	170.0	0.00	5.10	
168	072303	BARNARD	BAYSIDE	SAG	4.8/8.32 kV Wye Grounded	11.12	11.12	706	74.00	12	5	0.030	63.5	0.00	11.12	
169	072304	BARNARD	BARNARD	SAG	4.8/8.32 kV Wye Grounded	11.43	11.43	774	0.00	12	6	0.000	67.7	0.00	11.43	
170	072402	THAYER	LUFKIN RULE	SAG	4.8/8.32 kV Wye Grounded	8.04	8.04	861	58.5	5	5	0.083	107.1	8.04	0.00	
171	072701	BURLINGAME	BURLINGAME	GRA	7.2/12.47 kV Wye Grounded	14.68	14.68	2026	31.00	5	4	0.045	138.0	14.68	0.00	
172	072703	BURLINGAME	NEWHALL	GRA	7.2/12.47 kV Wye Grounded	11.54	11.54	2109	453.00	5	3	0.029	182.8	11.54	0.00	
173	072801	LAINGSBURG	LELAND ROAD	OWS	4.8/8.32 kV Wye Grounded	37.57	20.00	1181	120.08	21				0.00	20.00	Carryover
174	074401	PINE RIVER	GRATIOT	ALM	4.8/8.32 kV Wye Grounded	5.23	5.23	855	186.00	5	3	0.064	163.5	5.23	0.00	
175	074404	PINE RIVER	ALGER	ALM	4.8/8.32 kV Wye Grounded	24.93	24.93	951	20.33	11	9	0.040	38.1	0.00	24.93	
176	074801	WEBB ROAD	HALE	TWS	4.8/8.32 kV Wye Grounded	39.58	39.36	724	31.74	10	10	0.160	18.3	0.00	39.36	
177	074802	WEBB ROAD	PLAINFIELD	TWS	4.8/8.32 kV Wye Grounded	20.71	20.63	511	53.5	11	12	0.225	24.7	0.00	20.63	
178	074903	WURTSMITH	AIR BASE	TWS	12.0 kV Delta	19.34	19.34	913	0.00	38	18	0.000	47.2	0.00	19.34	
179	075101	YORKVILLE	HIGHLAND PARK	KAL	4.8/8.32 kV Wye Grounded	18.28	18.28	628	22.69	5	7	0.237	34.4	18.28	0.00	
180	076502	LOVELL	BRONSON	KAL	4.8/8.32 kV Wye Grounded	0.36	0.36	2	0	38	18	0.000	5.6	0.00	0.36	
181	076504	LOVELL	UNICAP	KAL	4.8/8.32 kV Wye Grounded	0.39	0.39	1	0	38	18	0.000	2.6	0.00	0.39	
182	076505	LOVELL	JASPER STREET	KAL	4.8/8.32 kV Wye Grounded	0.45	0.45	5	0.00	38	18	0.000	11.1	0.00	0.45	
183	076507	LOVELL	HENRIETTA	KAL	4.8/8.32 kV Wye Grounded	1.06	1.06	71	0.00	38	18	0.000	67.0	0.00	1.06	
184	076508	LOVELL	MBT	KAL	4.8/8.32 kV Wye Grounded	0.62	0.62	2	0.00	38	18	0.000	3.2	0.00	0.62	
185	076509	LOVELL	FINE ARTS	KAL	4.8/8.32 kV Wye Grounded	1.16	1.16	204	0.00	38	18	0.000	175.9	0.00	1.16	
186	076510	LOVELL	MEDIC	KAL	4.8/8.32 kV Wye Grounded	0.77	0.77	189	0.00	38	18	0.000	245.5	0.00	0.77	
187	076511	LOVELL	GIBSON	KAL	4.8/8.32 kV Wye Grounded	5.40	5.40	400	6.00	12	6	0.062	74.1	0.00	5.40	
188	076601	JUDD ROAD	JOLSON	FLT	4.8/8.32 kV Wye Grounded	17.04	17.04	1695	72.50	16	8	0.039	99.5	0.00	17.04	
189	076602	JUDD ROAD	OTTAWA	FLT	4.8/8.32 kV Wye Grounded	12.12	12.12	435	78.77	38	24	0.358	35.9	0.00	12.12	
190	076603	JUDD ROAD	AINSWORTH	FLT	4.8/8.32 kV Wye Grounded	18.77	18.77	1455	271.00	15	10	0.053	77.5	0.00	18.77	
191	076604	JUDD ROAD	HOLIDAY	FLT	4.8/8.32 kV Wye Grounded	10.40	10.40	316	197.75	26	17	0.128	30.4	0.00	10.40	
192	076605	JUDD ROAD	CARMANWOOD	FLT	4.8/8.32 kV Wye Grounded	12.06	12.06	1286	68.83	33	21	0.166	106.6	0.00	12.06	
193	076606	JUDD ROAD	MANDEVILLE	FLT	4.8/8.32 kV Wye Grounded	9.11	9.11	953	24.00	9	8	0.110	104.6	0.00	9.11	
194	077001	CURTIS	MAGRUDDER	CLR	4.8/8.32 kV Wye Grounded	49.82	49.82	570	102.40	5	9	0.100	11.4	49.82	0.00	
195	078302	FOX FARM	GRANT	LDG	7.2/12.47 kV Wye Grounded	53.46	53.46	556	35.00	11	9	0.069	10.4	0.00	53.46	
196	078801	HONOR	INDIAN HILL	BEN	7.2/12.47 kV Wye Grounded	70.98	45.00	979	123.59	9				0.00	45.00	Carryover
197	079202	MIDDLEVILLE	LAFAYETTE	HST	4.8/8.32 kV Wye Grounded	53.88	33.00	1267	71.76	23				0.00	33.00	Carryover
198	080302	BOYNE MTN	MOUNTAIN LODGE	BNC	7.2/12.47 kV Wye Grounded	5.34	5.34	284	0.00	5	2	0.000	53.2	5.34	0.00	
199	081501	HARPER ROAD	ARENS	LAN	14.4/24.9 kV Wye Grounded	36.01	36.01	1290	144.23	5	23	0.287	35.8	36.01	0.00	
200	081601	HAGADORN	WATER	LAN	4.8/8.32 kV Wye Grounded	30.53	30.53	806	203.2	11				0.00	30.53	Carryover
201	081603	HAGADORN	HAGADORN	LAN	4.8/8.32 kV Wye Grounded	41.93	41.93	890	96.60	24	22	0.119	21.2	0.00	41.93	
202	082502	NORTHERN FIBRE	CAREERLINE	HML	4.8/8.32 kV Wye Grounded	19.01	19.01	236	58.36	38	19	0.193	12.4	0.00	19.01	
203	083502	JACKMAN	INDUSTRIAL	SMN	7.2/12.47 kV Wye Grounded	8.53	8.53	322	0	5	2	0.000	37.7	8.53	0.00	
204	084101	LOVEJOY	BRADEN	OWS	14.4/24.9 kV Wye Grounded	112.67	112.67	1241	57.82	5	33	0.112	11.0	112.67	0.00	
205	088502	BURTCH ROAD	WELCH LAKE	JAC	14.4/24.9 kV Wye Grounded	36.28	36.28	707	90.57	5	23	0.129	19.5	36.28	0.00	
206	090804	OAK STREET	PLYMOUTH	JAC	4.8/8.32 kV Wye Grounded	4.01	4.01	318	0	12	6	0.000	79.3	0.00	4.01	
207	090806	OAK STREET	HARRIS BLDG/PEARL ST	JAC	4.8 kV Delta	0.97	0.97	67	0.00	38	27	0.000	69.1	0.00	0.97	
208	090807	OAK STREET	BELL/MECHANIC	JAC	4.8 kV Delta	1.17	1.17	15	0	38	27	0.000	12.8	0.00	1.17	

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	Feeder ID	Substation	Circuit	HQ	Voltage	Circuit Miles	Work Plan Miles	Circuit Customers	Average Outages per Incident	Years Since Last Cleared	Relative Risk Score (0-100)	3-Year Weighted Average Incidents per Mile	Customer Density per Mile	On Cycle Miles	Backlog Miles	Notes
209	091602	AMPERSEE	BORGESS	KAL	4.8/8.32 kV Wye Grounded	5.14	5.14	771	183.50	5	4	0.130	150.0	5.14	0.00	
210	093202	BOON ROAD	ROUND LAKE	CAD	4.8/8.32 kV Wye Grounded	26.45	26.45	495	83.57	11	7	0.088	18.7	0.00	26.45	
211	093401	CALVIN	BELTLINE	GRE	7.2/12.47 kV Wye Grounded	5.70	5.70	854	0.00	5	2	0.000	149.8	5.70	0.00	
212	093405	CALVIN	CALVIN	GRE	7.2/12.47 kV Wye Grounded	0.02	0.02	1	0	34	16	0.000	50.0	0.00	0.02	
213	096601	VENTURA	WATER TREAT	HML	14.4/24.9 kV Wye Grounded	0.00	0.00	2	0.00	38	18	0.000	0.0	0.00	0.00	
214	100302	NINETEEN MILE RD	INDUSTRIAL PARK	BIG	7.2/12.47 kV Wye Grounded	30.52	10.00	847	80.78	12				0.00	10.00	Carryover
215	100802	HARRIETTA	BOON	CAD	14.4 kV Delta	126.85	90.00	1326	170.1	9				0.00	90.00	Carryover
216	102202	FILLMORE	64TH STREET	GRA	7.2/12.47 kV Wye Grounded	21.26	21.26	709	188.5	11				0.00	21.26	Carryover
217	103301	SQUIRE HILL	EDGEWATER	FLT	4.8/8.32 kV Wye Grounded	21.92	21.92	1591	36.60	38	24	0.076	72.6	0.00	21.92	
218	103302	SQUIRE HILL	HILLSIDE	FLT	4.8/8.32 kV Wye Grounded	16.47	16.47	963	26.31	38	22	0.263	58.5	0.00	16.47	
219	103503	KNAPP	PERKINS	GRA	7.2/12.47 kV Wye Grounded	18.98	18.98	2616	484.56	5	39	0.158	137.8	18.98	0.00	
220	104101	GILSON	WYMAN	ALM	14.4/24.9 kV Wye Grounded	69.05	15.00	777	24.86	21				0.00	15.00	Carryover
221	106901	THOMAS	FROST	SAG	4.8/8.32 kV Wye Grounded	72.54	42.00	1632	40.13	14				0.00	42.00	Carryover
222	107502	OBERLIN	BENMARK	CLR	14.4/24.9 kV Wye Grounded	171.37	14.30	3026	161.63	18				0.00	14.30	Carryover
223	107603	ISABELLA	MISSION	ALM	4.8/8.32 kV Wye Grounded	10.17	10.17	1063	0.00	5	3	0.000	104.5	10.17	0.00	
224	107604	ISABELLA	REMUS	ALM	4.8/8.32 kV Wye Grounded	13.13	13.13	617	0	5	3	0.000	47.0	13.13	0.00	
225	108102	BECK ROAD	OTTAWA	SMN	7.2/12.47 kV Wye Grounded	17.27	17.27	272	0.00	28	14	0.000	15.7	0.00	17.27	
226	108802	GOLDEN	CONTINENTAL	MDL	4.8/8.32 kV Wye Grounded	5.25	5.25	334	62.00	10	4	0.063	63.6	0.00	5.25	
227	108803	GOLDEN	ROCKWELL	MDL	4.8/8.32 kV Wye Grounded	11.33	11.33	797	154.00	31	15	0.118	70.3	0.00	11.33	
228	109101	HENDERSHOT	MONROE ROAD	ADR	7.2/12.47 kV Wye Grounded	62.50	62.50	1213	118.71	13	35	0.091	19.4	0.00	62.50	
229	109802	PIGEON LAKE	OLIVE	HML	4.8/8.32 kV Wye Grounded	64.14	64.14	1065	26.20	5	10	0.130	16.6	64.14	0.00	
230	110801	WILLIAMS	ELY	HML	4.8/8.32 kV Wye Grounded	26.67	26.67	1060	73.18	9	27	0.687	39.7	0.00	26.67	
231	110803	WILLIAMS	LINCOLN	HML	4.8/8.32 kV Wye Grounded	23.63	23.63	580	78.13	5	10	0.212	24.5	23.63	0.00	
232	111801	BAY ROAD	DAVIS ROAD	SAG	14.4/24.9 kV Wye Grounded	8.10	8.10	131	0.00	24	11	0.000	16.2	0.00	8.10	
233	111803	BAY ROAD	SEARS	SAG	14.4/24.9 kV Wye Grounded	9.63	9.63	126	0.00	38	18	0.000	13.1	0.00	9.63	
234	111804	BAY ROAD	BAY ROAD	SAG	14.4/24.9 kV Wye Grounded	12.27	12.27	434	0.00	24	11	0.000	35.4	0.00	12.27	
235	112601	CASCADE	THORNCREST	GRE	4.8/8.32 kV Wye Grounded	37.48	37.48	1468	181.8	9	12	0.222	39.2	0.00	37.48	
236	112603	CASCADE	PEACE STREET	GRE	4.8/8.32 kV Wye Grounded	43.70	43.70	1468	132.32	11	28	0.214	33.6	0.00	43.70	
237	113403	HARING	INDUSTRIAL	CAD	4.8/8.32 kV Wye Grounded	5.34	5.34	55	0.00	5	2	0.000	10.3	5.34	0.00	
238	114203	MASON	SOUTH STREET	LAN	4.8/8.32 kV Wye Grounded	15.12	15.12	1471	260.07	5	17	0.309	97.3	15.12	0.00	
239	115001	GRAND RIVER	SOUTH MALL	LAN	4.8/8.32 kV Wye Grounded	0.31	0.31	1	0.00	38	18	0.000	3.2	0.00	0.31	
240	115003	GRAND RIVER	NORTH MALL	LAN	4.8/8.32 kV Wye Grounded	0.35	0.35	0	0.00	37	17	0.000	0.0	0.00	0.35	
241	115005	GRAND RIVER	NEWMAN ROAD	LAN	4.8/8.32 kV Wye Grounded	3.82	3.82	127	0	37	17	0.000	33.2	0.00	3.82	
242	118401	NEWBURG	BANCROFT	OWS	14.4/24.9 kV Wye Grounded	41.33	41.33	711	82.64	17	21	0.202	17.2	0.00	41.33	
243	119201	CHAUVEZ	PARK	LDG	7.2/12.47 kV Wye Grounded	12.21	12.21	321	114	5	5	0.355	26.3	12.21	0.00	
244	119202	CHAUVEZ	PUMP STORAGE	LDG	7.2/12.47 kV Wye Grounded	1.78	1.78	1	0.00	5	2	0.000	0.6	1.78	0.00	
245	120201	TUCKER	MACKEY	FLT	4.8/8.32 kV Wye Grounded	32.65	13.50	755	76.88	23				0.00	13.50	Carryover
246	121002	NORTH KENT	MALL	GRN	7.2/12.47 kV Wye Grounded	6.27	6.27	804	0.00	12	14	0.000	128.2	0.00	6.27	
247	121003	NORTH KENT	NORTHVILLE	GRN	7.2/12.47 kV Wye Grounded	11.31	11.31	939	274.33	5	10	0.088	83.0	11.31	0.00	
248	121004	NORTH KENT	FIVE MILE	GRN	7.2/12.47 kV Wye Grounded	16.75	16.75	1202	146.00	12	21	0.199	71.8	0.00	16.75	
249	121005	NORTH KENT	GILL	GRN	7.2/12.47 kV Wye Grounded	1.55	1.55	1	1.00	14	6	0.215	0.6	0.00	1.55	
250	122501	CRAWFORD	DEERFIELD	ALM	4.8/8.32 kV Wye Grounded	18.51	18.51	1366	0	5	2	0.000	73.8	18.51	0.00	
251	122705	STEEL DRIVE	PONCHATRAIN	FLT	4.8/8.32 kV Wye Grounded	44.21	44.21	1523	64.31	19				0.00	44.21	Carryover
252	123102	BIG PRAIRIE	OXBOW	BIG	4.8/8.32 kV Wye Grounded	34.37	34.37	801	183.38	6	26	0.378	23.3	0.00	34.37	
253	124205	BRETON	TOWERS	GRA	7.2/12.47 kV Wye Grounded	10.52	10.52	1279	58	37				0.00	10.52	Carryover
254	124702	FARRINGTON	LAKOLA RD	BIG	4.8/8.32 kV Wye Grounded	11.92	11.92	132	15.75	17	8	0.112	11.1	0.00	11.92	
255	127001	RANGER LAKE	KOKOSING	TWS	14.4/24.9 kV Wye Grounded	41.84	41.80	1386	121.92	5	43	0.303	33.1	41.80	0.00	
256	127302	WHITTEMORE	M-65	TWS	14.4/24.9 kV Wye Grounded	136.24	88.75	1650	74.70	11	24	0.147	12.1	0.00	88.75	
257	127502	EAST TAWAS	LINCOLN STREET	TWS	14.4/24.9 kV Wye Grounded	63.50	20.00	3009	414.00	7				0.00	20.00	Carryover
258	127901	CAMBRIDGE	SPEEDWAY	JAC	4.8/8.32 kV Wye Grounded	9.00	9.00	65	0	5	2	0.000	7.2	9.00	0.00	
259	127903	CAMBRIDGE	INFIELD #1	JAC	4.8/8.32 kV Wye Grounded	0.68	0.68	1	0.00	5	2	0.000	1.5	0.68	0.00	
260	128802	BENNETT	JOLLY ROAD	LAN	4.8/8.32 kV Wye Grounded	15.97	15.97	1244	315.89	26				0.00	15.97	Carryover

Line No.	Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Feeder ID	Substation	Circuit	HQ	Voltage	Circuit Miles	Work Plan Miles	Circuit Customers	Average Outages per Incident	Years Since Last Cleared	Relative Risk Score (0-100)	3-Year Weighted Average Incidents per Mile	Customer Density per Mile	On Cycle Miles	Backlog Miles	Notes
261	129002	PEACOCK	COLEMAN ROAD	LAN	4.8/8.32 kV Wye Grounded	42.71	42.71	2426	172.87	5	12	0.117	56.8	42.71	0.00	
262	129301	JOHNSON	LINCOLN	MUS	4.8/8.32 kV Wye Grounded	72.39	72.39	1042	51.86	16	23	0.235	14.4	0.00	72.39	
263	129302	JOHNSON	CEDAR	MUS	4.8/8.32 kV Wye Grounded	58.19	12.00	1225	170.47	19				0.00	12.00	Carryover
264	129603	BLACKMAN	MEIJERS	JAC	14.4/24.9 kV Wye Grounded	13.80	13.80	886	52.00	5	3	0.024	64.2	13.80	0.00	
265	129604	BLACKMAN	INDUSTRIAL	JAC	14.4/24.9 kV Wye Grounded	0.65	0.65	2	0.00	5	2	0.000	3.1	0.65	0.00	
266	129801	VANDERBILT	CORWITH	BNC	13.2 kV Delta	17.73	17.71	387	47.56	6	4	0.169	21.8	0.00	17.71	
267	131402	BELKNAP	TODD FARM	HML	4.8/8.32 kV Wye Grounded	37.77	20.00	378	27.45	38				0.00	20.00	Carryover
268	132301	ORCHARD ROAD	MIDLAND HOSPITAL 1	MDL	4.8/8.32 kV Wye Grounded	0.64	0.64	2	0.00	38	18	0.000	3.1	0.00	0.64	
269	132302	ORCHARD ROAD	MIDLAND HOSPITAL 2	MDL	4.8/8.32 kV Wye Grounded	0.55	0.55	0	0.00	38	18	0.000	0.0	0.00	0.55	
270	132303	ORCHARD ROAD	SAGINAW ROAD	MDL	4.8/8.32 kV Wye Grounded	0.56	0.56	0	0.00	10	4	0.000	0.0	0.00	0.56	
271	132304	ORCHARD ROAD	ST ANDREWS	MDL	4.8/8.32 kV Wye Grounded	0.06	0.06	0	0.00	8	3	0.000	0.0	0.00	0.06	
272	134802	PAVILION	MERIDETH	KAL	4.8/8.32 kV Wye Grounded	15.79	15.79	1148	50.25	12	9	0.084	72.7	0.00	15.79	
273	135302	VILLAGE GREEN	SOUTHLAND	KAL	4.8/8.32 kV Wye Grounded	7.22	7.22	1421	1412.00	38	34	0.046	196.8	0.00	7.22	
274	135304	VILLAGE GREEN	CROSSROADS	KAL	4.8/8.32 kV Wye Grounded	1.50	1.50	95	0.00	37	17	0.000	63.3	0.00	1.50	
275	136603	M.A.E.	MONROE AUTO	SMN	7.2/12.47 kV Wye Grounded	0.00	0.00	1	0.00	38	18	0.000	0.0	0.00	0.00	
276	139501	WARNER	MILO	KAL	14.4/24.9 kV Wye Grounded	122.47	100.00	1863	169.85	6				0.00	100.00	Carryover
277	140401	ALGER	SKIDWAY	WBR	14.4/24.9 kV Wye Grounded	132.36	132.27	4252	169.73	5	100	0.544	32.1	132.27	0.00	
278	141202	BACKUS	MAPLE VALLEY	WBR	14.4/24.9 kV Wye Grounded	60.92	60.79	1073	89.63	5	24	0.131	17.6	60.79	0.00	
279	148301	MANNSIDING	CEDAR	CLR	14.4/24.9 kV Wye Grounded	65.60	65.60	1680	258.09	8	34	0.173	25.6	0.00	65.60	
280	148501	CRAHEN	GREENBRIER	GRA	7.2/12.47 kV Wye Grounded	16.41	16.41	399	62.80	5	5	0.102	24.3	16.41	0.00	
281	148602	DEER LAKE	BALL AVENUE	CLR	4.8/8.32 kV Wye Grounded	45.11	45.11	1472	161.92	10	33	0.288	32.6	0.00	45.11	
282	150002	WITHEY LAKE	HENDERSON	WBR	14.4/24.9 kV Wye Grounded	16.54	16.54	211	69.93	38	24	0.302	12.8	0.00	16.54	
283	151102	LELAND	LELAND	TRA	7.2/12.47 kV Wye Grounded	56.63	25.00	1310	145.69	16				0.00	25.00	Carryover
284	152703	COIT AVENUE	RIFLE RANGE	GRN	7.2/12.47 kV Wye Grounded	6.16	6.16	509	107.6	9				0.00	6.16	Carryover
285	154201	SPICEBUSH	LESTER LAKE	KAL	14.4 kV Delta	50.61	50.61	784	142.55	10	51	0.323	15.5	0.00	50.61	
286	154301	HARVARD LAKE	HARVARD LAKE	GVL	14.4/24.9 kV Wye Grounded	105.09	105.09	1969	70.47	5	46	0.343	18.7	105.09	0.00	
287	155002	SMITH CREEK	WRIGHT	WBR	14.4/24.9 kV Wye Grounded	18.56	18.56	981	191.25	38	25	0.144	52.9	0.00	18.56	
288	155501	WOODWARD	WOODWARD LAKE	CAD	14.4 kV Delta	75.99	75.99	894	58.31	9	10	0.057	11.8	0.00	75.99	
289	155801	SCHOOL ROAD	MOROCCO	SMN	7.2/12.47 kV Wye Grounded	49.08	48.75	1063	55.17	8	18	0.238	21.7	0.00	48.75	
290	155802	SCHOOL ROAD	ST ANTHONY	SMN	7.2/12.47 kV Wye Grounded	25.85	25.61	645	55.6	5	11	0.129	25.0	25.61	0.00	
291	158201	RYNO	MORENCI	WBR	14.4/24.9 kV Wye Grounded	70.39	35	1719	158.24	8	34	0.099	24.4	0.00	35.00	
292	158701	ROLLIN	BURTON	ADR	4.8/8.32 kV Wye Grounded	26.55	26.55	262	73	38	21	0.063	9.9	0.00	26.55	
293	158702	ROLLIN	POSEY LAKE	ADR	4.8/8.32 kV Wye Grounded	16.69	16.69	354	56.5	38	22	0.160	21.2	0.00	16.69	
294	160201	BARRYTON	BARRYTON	BIG	14.4/24.9 kV Wye Grounded	49.41	49.41	711	86.66	5	42	0.236	14.4	49.41	0.00	
295	162201	FLETCHER	ODEN	BNC	13.2 kV Delta	46.93	20	1879	169.19	8				0.00	20.00	Carryover
296	163702	WILLIS ROAD	TIMS LAKE ROAD	JAC	14.4/24.9 kV Wye Grounded	3.6	3.6	25	0	19	9	0.000	6.9	0.00	3.60	
297	167301	THORNTON	WEST RIVER RD	MDL	4.8/8.32 kV Wye Grounded	32.19	9	1215	119	10				0.00	9.00	Carryover
298	167302	THORNTON	NIELSON RD	MDL	4.8/8.32 kV Wye Grounded	65.83	65.83	1027	40.92	16				0.00	65.83	Carryover
299	167901	MURNER	VAN TYLE	BNC	14.4/24.9 kV Wye Grounded	21.68	15	581	51	6				0.00	15.00	Carryover
300	169301	VIPOND	RAINBOW	TRA	7.2/12.47 kV Wye Grounded	0.12	0.12	0	0	5	2	0.000	0.0	0.12	0.00	
301	169302	VIPOND	STEELHEAD	TRA	7.2/12.47 kV Wye Grounded	1.79	1.73	26	0	5	2	0.000	14.5	1.73	0.00	
302	169303	VIPOND	BROOK	TRA	7.2/12.47 kV Wye Grounded	57.8	57.59	1384	46.22	23	13	0.052	23.9	0.00	57.59	
303	169304	VIPOND	SPLAKE	TRA	7.2/12.47 kV Wye Grounded	19.13	19.09	713	26	23	11	0.035	37.3	0.00	19.09	

EXHIBIT A-190 (SES-5)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Forestry Operations
($000)

Case No.: U-22070
Exhibit No.: A-191 (SES-6)
Page: 1 of 2
Witness: SEStewart
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
1	**Forestry Operations Administration and Work Planning - baseline**	**8,482**	**9,521**
	Labor	3,680	4,308
	Material	0	0
	Contractor	3,963	3,905
	Non-Labor Overhead	838	1,307
	Non-Labor Other	0	0
2	**Line Clearing Contractor Costs - baseline**	**126,695**	**158,229**
	Labor	0	0
	Material	0	0
	Contractor	126,695	158,229
	Non-Labor Overhead	0	0
	Non-Labor Other	0	0
3	**Total Forestry Operations O&M Expenses - baseline**	**135,176**	**167,749**
	Labor	3,680	4,308
	Material	0	0
	Contractor	130,658	162,134
	Non-Labor Overhead	838	1,307
	Non-Labor Other	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Forestry Operations
($000)

Case No.: U-22070
Exhibit No.: A-191 (SES-6)
Page: 2 of 2
Witness: SEStewart
Date: June 2026

Line No.	(a) Description	(b) Actual 12 Mos Ending 12/31/2025	(c) Inflation Applied to Projected Test Year (b) * Compounded Inflation Rate	(d) Scope/Cost Increases Net of Productivity Gains	(e) Projected O&M 12 Mos Ending 4/30/2028 (b) + (c) + (d)
1	Forestry Operations Administration and Work Planning - baseline	8,482	$ 530	$ 509	$ 9,521
2	Line Clearing Contractor Costs - baseline	126,695	$ 7,913	$ 23,621	$ 158,229
3	Total Forestry Operations O&M Expenses - baseline	**135,176**	**8,443**	**24,130**	**167,749**

Notes

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Analysis of Projected Costs, Cost Savings, and Reliability Improvements of Implementing a Four-Year Cycle for LVD Circuits

Case No.: U-22070
Exhibit No.: A-192 (SES-7)
Page: 1 of 1
Witness: SEStewart
Date: June 2026

Line No.	(a) Scenario	(b) Description	(c) 2027 Calendar Year	(d) 2028 Calendar Year	(e) 2029 Calendar Year	(f) 2030 Calendar Year	(g) 2031 Calendar Year
2	**Electric LVD Current State[1]**	Total O&M Costs	$130,573,478	$133,184,948	$135,848,647	$138,565,619	$141,336,932
3		O&M Contractor Costs	$126,487,062	$129,016,803	$131,597,139	$134,229,082	$136,913,664
4		Line Clearing Crews	378	372	366	361	361
5		Internal FTEs and Contract Planning/Supervision	89	89	89	89	89
6		O&M Clearing Miles	7,713	7,973	8,267	8,853	9,371
7		Primary and Circuit Tree-Caused Outage Incidents	9,006	8,834	8,649	8,381	8,021
8		Primary and Circuit Tree-Caused SAIFI	0.5296	0.5206	0.5111	0.4973	0.4789
9		Primary and Circuit Tree-Caused SAIDI (minutes)	353.76	347.51	340.88	331.26	318.45
10	**Electric LVD 5-Year Cycle**	Total O&M Costs	$201,845,786	$228,149,213	$233,145,437	$240,127,560	$191,994,274
11		O&M Contractor Costs	$195,186,153	$221,251,853	$226,081,679	$232,870,655	$184,690,950
12		Line Clearing Crews	545	587	590	590	495
13		Internal FTEs and Contract Planning/Supervision	104	109	109	109	91
14		O&M Clearing Miles	11,063	12,978	13,697	14,959	12,464
15		Primary and Circuit Tree-Caused Outage Incidents	8,862	8,450	7,897	7,004	6,605
16		Primary and Circuit Tree-Caused SAIFI	0.5220	0.5006	0.4719	0.4259	0.4058
17		Primary and Circuit Tree-Caused SAIDI (minutes)	348.48	333.53	313.59	281.52	267.48
18	**Electric LVD 4-Year Cycle**	Total O&M Costs	$201,845,786	$245,497,217	$277,331,141	$301,630,863	$289,709,914
19		O&M Contractor Costs	$195,186,153	$238,090,723	$269,241,520	$293,050,883	$280,940,504
20		Line Clearing Crews	545	616	664	694	666
21		Internal FTEs and Contract Planning/Supervision	104	116	124	132	128
22		O&M Clearing Miles	11,063	13,818	16,040	18,446	17,953
23		Primary and Circuit Tree-Caused Outage Incidents	8,862	8,409	7,668	6,501	6,266
24		Primary and Circuit Tree-Caused SAIFI	0.5220	0.4984	0.4600	0.3998	0.3883
25		Primary and Circuit Tree-Caused SAIDI (minutes)	348.48	332.01	305.28	263.34	255.31
26	**Implementing a 5-Year Cycle**	Incremental Line Clearing Crews	167	215	224	229	134
27		Incremental O&M Costs	$71,272,308	$94,964,265	$97,296,790	$101,561,941	$50,657,343
28		Estimated Service Restoration Benefit	$921,482	$2,506,430	$5,006,594	$9,351,013	$9,808,173
29		Estimated Customer Benefit	$23,298,783	$62,727,298	$125,146,953	$232,608,482	$243,020,522
30		Net Benefit	-$47,052,043	-$29,730,537	$32,856,757	$140,397,553	$202,171,353
31	**Implementing a 4-Year Cycle**	Incremental Line Clearing Crews	167	244	298	333	305
32		Incremental O&M Costs	$71,272,308	$112,312,269	$141,482,494	$163,065,244	$148,372,982
33		Estimated Service Restoration Benefit	$921,482	$2,774,044	$6,531,208	$12,766,814	$12,156,316
34		Estimated Customer Benefit	$23,298,783	$69,589,495	$163,204,700	$317,637,090	$301,123,979
35		Net Benefit	-$47,052,043	-$39,948,731	$28,253,414	$167,338,660	$164,907,313
36	**Comparing Implementing 4-Year to Implementing 5-Year**	Incremental Line Clearing Crews	0	29	74	104	171
37		Incremental O&M Costs	$0	$17,348,004	$44,185,704	$61,503,303	$97,715,640
38		Estimated Service Restoration Benefit	$0	$267,614	$1,524,614	$3,415,802	$2,348,143
39		Estimated Customer Benefit	$0	$6,862,197	$38,057,747	$85,028,608	$58,103,457
40		Net Benefit	**$0**	**-$10,218,193**	**-$4,603,343**	**$26,941,107**	**-$37,264,040**

[1] Maintaining the level of 2025 LVD Total O&M Costs, applying inflation annually

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Analysis of Costs, Benefits, and Reliability Improvements of Removing 100% of Tree Canopy in First Zones

Case No.: U-22070
Exhibit No.: A-237 (SES-8)
Page: 1 of 2
Witness: SEStewart
Date: June 2026

Line No.		(a) 2027 Calendar Year	(b) 2028 Calendar Year	(c) 2029 Calendar Year	(d) 2030 Calendar Year	(e) 2031 Calendar Year
	Current Strategy: Canopy Removal on Targeted Three Phase Portions of Circuits					
1	LVD Total O&M Costs	$201,845,786	$228,149,213	$233,145,437	$240,127,560	$191,994,274
2	Estimated Annual Canopy Removal Miles	1,044.2	1,229.2	1,303.5	1,423.3	200.0
3	Tree-Caused Outage Incidents	8,862	8,450	7,897	7,004	6,605
4	Tree-Caused SAIFI	0.5220	0.5006	0.4719	0.4259	0.4058
5	Tree-Caused SAIDI (minutes)	348.48	333.53	313.59	281.52	267.48
	Current Strategy with Remaining 1st Zone Miles Added					
6	LVD Total O&M Costs	$202,705,137	$229,119,466	$234,137,324	$241,162,994	$192,139,277
7	Estimated Annual Canopy Removal Miles	155.2	182.7	193.7	211.5	29.7
8	Tree-Caused Outage Incidents	8,861	8,449	7,896	7,003	6,605
9	Tree-Caused SAIFI	0.5218	0.5003	0.4716	0.4256	0.4058
10	Tree-Caused SAIDI (minutes)	348.35	333.37	313.42	281.34	267.45
	Comparing the Current Strategy to the Current Strategy with Remaining 1st Zone Miles Added					
11	Incremental LVD O&M Costs	$859,351	$970,253	$991,887	$1,035,434	$145,003
12	Estimated Service Restoration Benefit	$6,399	$6,527	$6,658	$6,791	$0
13	Estimated Customer Benefit	$601,489	$831,893	$873,435	$914,049	$66,321
14	**Net Benefit**	**-$251,462**	**-$131,833**	**-$111,794**	**-$114,593**	**-$78,682**

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Analysis of Costs, Benefits, and Reliability Improvements of Removing 100% of Tree Canopy in First Zones

Case No.: U-22070
Exhibit No.: A-237 (SES-8)
Page: 2 of 2
Witness: SEStewart
Date: June 2026

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
						2021-2025 Actual Tree-Caused Outages Including MED				5-Yr Avg Tree-Caused Outages Including MED			Estimated Reliability Benefit of Canopy Removal		
Line No	Description	3 Phase Primary Miles	2 Phase Primary Miles	1 Phase Primary Miles	Customers Served Downstream	Incidents	Customers Interrupted	SAIDI (min)	Customer Minutes (min)	Incidents	Customers Interrupted per Incident	CAIDI (min)	Incidents	Customers Interrupted	SAIDI (min)
1	100% of First Zones	3,514.6	74.7	176.5	1,898,877	1,661	1,294,417	375.39	703,422,396	332	779	543.43	20	15,586	4.46
2	First Zones with >=350 Customers Downstream	2,993.0	68.8	155.5	1,846,004	1,501	1,234,684	355.82	666,788,374	300	823	540.05	19	15,629	4.44
3	3 Phase Portions of First Zones with >=350 Customers Downstream[1]	2,993.0	-	-	1,846,004	1,396	1,148,580	331.01	620,288,071	279	823	540.05	17	13,984	3.98
4	Remaining First Zones (difference between line 1 and line 3)	521.5	74.7	176.5	52,873	265	145,837	44.39	83,134,325	53	551	570.05	4	2,205	0.66

Note[1]: 2021-2025 reliability metrics estimated by discounting to % exposure corridor miles - 3 phase to total.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

BRIAN J. VANBLARCUM

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the Property Tax Rate for the Test Year

Case No.: U-22070
Exhibit No.: A-193 (BJV-1)
Page: 1 of 3
Witness: BJVanBlarcum
Date: June 2026

Line No.	(a) Description	(b) Amount (millions)	(c) Amount (millions)	(d) Amount (millions)	(e) Source
1	Electric Property Taxes Paid - 2027 Estimate			$ 312.1	WP BJV-5, L-5
2	Electric Property Taxes on 2027 Plant Investment			32.1	Ex. A-193 (BJV-1), p.2, L-9
3	2028 Fossil Plant Valuation Tax Reduction			(0.1)	WP BJV-5, L-5
4	Electric Property Taxes on Real Property Taxable Value Increases			1.2	Ex. A-193 (BJV-1), p.3, L-4
5	Electric Property Taxes to be Paid - 2028			$ 345.3	
6	2027 Fiscal Year Property Taxes expensed in 2028			156.1	(Line 1 * 50.0%) [1]
7	2028 Property Taxes expensed in 2029			(172.7)	(Line 5 * 50.0%) [1]
8	Electric Property Tax Expense - 2028			$ 328.7	
9	Prorated Electric Property Tax Expense (May - December 2027)			196.2	WP BJV-5, L-10
10	Prorated Electric Property Tax Expense (January - April 2028)			105.6 [4]	
11	Prorated Electric Property Tax Expense			301.8	(L-10 + L-11)
12	2027 Estimated Year-End Plant-in-Service		$ 21,843.0 [2]		
13	2027 Estimated Construction Work-in-Progress	$ 826.5 [3]			
14	@ 50%	50.00%			
15	2027 Estimated Construction Work-in-Progress		$ 413.3		
16	Estimated Taxable Plant			$22,256.3	(L-13 + L-16)
17	Property Tax Rate			0.013560205	(L-12 / L-17)

Footnotes

[1] The 50.0% factor is from the 2025 CE Property Tax Fiscal Year Study

[2] Plant in Service Balance as of 12-31-2027; Plant Model U-22070; PIS (WP-HLP-22); Cell AH29 + JHC1&2 (WP-HLP-53), Cell AY18 + JHC3 (WP-HLP-53), Cell AY30

[3] Construction Work in Progress Balance as of 12-31-2027; Plant Model U-22070; CWIP (WP-HLP-23); Cell AI30

[4] Development of Estimated 2028 Prorated Property Tax Expense

2028 Estimated PT Expense	$ 328.7	Ex. A-180 (BJV-1), p. 1, L-9
Jan-Apr Expense Ratio	32.12%	Plant Model U-22070.xlsx; Input, Cells B215-E215
Prorated 2028 PT Expense	$ 105.6	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the 2028 Property Taxes
on 2027 Plant Investment

Case No.: U-22070
Exhibit No.: A-193 (BJV-1)
Page: 2 of 3
Witness: BJVanBlarcum
Date: June 2026

Line No.	(a) Description	(b) Amount (millions)		(c) Source
1	**Assessed Value of Personal Property (millions)**			
2	Year-end 2027 Estimated Taxable Closings less Retirements	$ 1,339.8	[1]	
3	First Year STC Multiplier	96.0%	[2]	
4	**True Cash Value of Personal Property (millions)**	$ 1,286.2		
5	Statutory Factor for Assessed Value	50%	[3]	
6	New Plant - Assessed Value	$ 643.1		
7	**Estimated Property Tax (millions)**			
8	Estimated Composite Millage Rate	49.8815	[4]	
9	Estimated 2028 Property Taxes Paid	$ 32.1		

Footnotes
[1] 2028 Electric Rate Case Property Tax Model
[2] Michigan Dept of Treasury Form 3589 - 1st year multiplier for Electric Distribution and Equipment
[3] Article IX, Section 3 of Constitution of Michigan of 1963
[4] CE Composite Millage Rate.xls

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the 2028 Estimated Electric Portion of
Real Property Taxable Value Increase

Case No.: U-22070
Exhibit No.: A-193 (BJV-1)
Page: 3 of 3
Witness: BJVanBlarcum
Date: June 2026

Line No.	(a) Description	(b) Amount (millions)	(c) Source
1	**2028 Estimated Electric Portion of Real Property Tax Increase (millions)**		
2	2028 Real Property Taxable Value - Estimated Electric Portion	$ 23.1 [1]	
3	2028 Estimated Composite Millage Rate	49.8815 [2]	
4	2028 Estimated Electric Portion of Real Property Taxable Value increase	$ 1.2	

Footnotes
[1] 2028 Electric Rate Case Property Tax Model
[2] CE Composite Millage Rate.xls

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Amortization of Excess Deferred Federal
Income Taxes for the Test Year

Case No.: U-22070
Exhibit No.: A-194 (BJV-2)
Page: 1 of 3
Witness: BJVanBlarcum
Date: June 2026

Line No.	(a) Description	(b) Projected Regulatory [1] Liability Amortization	(c) Projected Annual [2] Excess Deferred Tax	(d) Proration to Test Year
1	Protected Plant Balance - Subject to ARAM			
2	2027	(39,904,000)	(29,756,000)	(19,837,000)
3	2028	(42,747,000)	(31,876,000)	(10,625,000)
4				
5	**TCJA Amortization - ARAM**			(30,462,000)
6				
7				
8				
9	Non-Protected Plant Balance - 27 years			
10	2027	3,145,000	2,345,000	1,563,000
11	2028	3,145,000	2,345,000	782,000
12				
13				
14	Non-Protected Other Balance - 10 years			
15	2027	(8,708,000)	(6,493,000)	(4,329,000)
16	2028	(8,708,000)	(6,493,000)	(2,164,000)
17				
18	**TCJA Amortization - Non ARAM**			(4,148,000)
19				
20				
21				
22	**TCJA Regulatory Liability**	2,821,501	2,104,000	2,104,000
23				
24				
25	**Total Test Year Excess Deferred Taxes**			(32,506,000)

[1] Based on the Company's regulatory liability amortization schedule approved in Case No. U-20309.
[2] Adjustment to pre-tax based on 1.341056 gross-up factor used in Case No. U-20309.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-22070
Exhibit No.: A-194 (BJV-2)
Page: 2 of 3
Witness: BJVanBlarcum
Date: June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CE Electric
Projected Tax Reform Regulatory Liability & Amortization
($000)

Case No.: U-20309
Exhibit No.: A-5 (SBM-3)
Page: 1 of 1
Witness: SBMcIntosh
Date: April 2019

Line No.	(a) Description	(b) Plant Diff *	(c) Oth Plant Diff ***	(d) All Other	(e) Total Electric
1	Amortization Period	ARAM	27	10	
2					
3	**Tax Reform Regulatory Asset (Liability) After Gross Up**	**$ (1,172,029)**	**$ 89,091**	**$ (87,076)**	**$ (1,170,013)**
4					
5	**Amortization Schedule**				
6	**2019	(8,953)	1,048	(2,903)	(10,807)
7	**2020	(28,209)	3,145	(8,708)	(33,771)
8	2021	(30,187)	3,145	(8,708)	(35,749)
9	2022	(31,436)	3,145	(8,708)	(36,998)
10	2023	(35,546)	3,145	(8,708)	(41,108)
11	2024	(36,898)	3,145	(8,708)	(42,460)
12	2025	(37,086)	3,145	(8,708)	(42,648)
13	2026	(37,134)	3,145	(8,708)	(42,697)
14	2027	(39,904)	3,145	(8,708)	(45,467)
15	2028	(42,747)	3,145	(8,708)	(48,309)
16	2029	(44,426)	3,145	(5,805)	(47,085)
17	2030	(45,859)	3,145	-	(42,713)
18	2031	(46,326)	3,145	-	(43,181)
19	2032	(47,316)	3,145	-	(44,170)
20	2033	(49,093)	3,145	-	(45,948)
21	2034	(51,089)	3,145	-	(47,944)
22	2035	(44,865)	3,145	-	(41,719)
23	2036	(42,334)	3,145	-	(39,189)
24	2037	(29,201)	3,145	-	(26,055)
25	2038	(26,019)	3,145	-	(22,874)
26	2039	(25,183)	3,145	-	(22,037)
27	2040	(24,370)	3,145	-	(21,225)
28	2041	(24,256)	3,145	-	(21,110)
29	2042	(24,259)	3,145	-	(21,114)
30	2043	(24,313)	3,145	-	(21,168)
31	2044	(24,345)	3,145	-	(21,199)
32	2045	(24,242)	3,145	-	(21,097)
33	2046	(24,063)	3,145	-	(20,918)
34	2047	(23,974)	3,120	-	(20,854)
35	2048 - 2056	(198,398)	-	-	(198,398)
36		**$ (1,172,029)**	**$ 89,091**	**$ (87,076)**	**$ (1,170,013)**

**** Subject to the normalization provisions of the Internal Revenue Code.***

***** Assumes Calculation C Interim Credit beginning September 2019 through December 2020.***

****** Includes a $4,168,278 beginning balance adjustment related to AFUDC approved by the Commission in U-21224.***

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-22070
Exhibit No.: A-194 (BJV-2)
Page: 3 of 3
Witness: BJVanBlarcum
Date: June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CE Electric
Tax Reform Regulatory Liability & Amortization

Case No.: U-20309
Date: March 2026

	(1) Beginning Balance [A]	(1-A) Rate Change Gross-up Adjustment [C]	(2) Amount Refunded	(3) Regulatory Asset (Liability)	(2-A) Regulatory Asset/(Liability) Refunded	(3-A) Remaining Regulatory Asset/ (Liability)	(4) Ending Balance
2019	$ (1,174,181,474)		$ 8,191,439	$ (6,240,769) [D]	$ 6,240,769	$ -	$ (1,159,749,266)
Beginning Balance Adj [B]	$ 4,168,278		$ -	$ -	$ -	$ -	$ (1,155,580,988)
2020	$ (1,155,580,988)		$ 33,772,000	$ (8,706,572) [E]	$ 8,706,572	$ -	$ (1,113,102,416)
2021	$ (1,113,102,416)		$ 35,750,000	$ (5,569,763) [F]	$ 4,652,422	$ (917,341)	$ (1,071,782,653)
2022	(1,071,782,653)		$ 36,999,000	$ (12,498,566) [G]	$ 1,895,000 [A]	$ (10,603,566)	$ (1,022,285,087)
2023	(1,022,285,087)	2,381,350	$ 41,109,000	$ 2,821,501	$ -	$ 2,821,501	$ (981,616,238)
2024	(981,616,238)	-	$ 42,367,000	$ (1,723,356)	$ -	$ (1,723,356)	$ (937,525,882)
2025	(937,525,882)	-	$ 42,555,000	$ (8,315,799)	$ -	$ (8,315,799)	$ (886,655,083)

[A] Electric information contained herein includes amounts associated with transmission assets, which are subject to rate regulation by the Federal Energy Regulatory Commission ("FERC"). On September 13, 2022, FERC issued a final order in Docket #ER22-2597-000 requiring $1,895,000 of TCJA-related excess deferred federal income taxes associated with transmission assets be refunded to transmission customers. This amount is reflected in column 2-A and reduced the Regulatory Asset/(Liability) due to customers as it will be refunded subject to the FERC order.

[B] In its original U-20309 filing, the Company inadvertently included in its unprotected plant balance a remeasurement of excess deferred taxes associated with AFUDC timing differences. A subsequent reconcilation of the 2019 TCJA balance highlighted this discrepancy. The Company reflected this proposed change in Case No. U-21224 and the Commission subsequently approved the adjustment in it's January 19, 2023 order.

[C] Gross-up change to the regulatory liability balance due to a statutory or apportionment rate change.

[D] Included in Case No. U-21224.

[E] Included in Case No. U-21389

[F] Included in Case No. U-21585

[G] Included in Case No. U-21870

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-22070

EXHIBITS

OF

MARK E. WITTBRODT

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2026

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Generating Unit Periodic Outages
May 1, 2027 Through April 30, 2028

Case No.: U-22070
Exhibit No.: A-195 (MEW-1)
Page: 1 of 1
Witness: MEWittbrodt
Date: June 2026

MAJOR OUTAGES: FOSSIL GENERATION AND LUDINGTON

Line No.	(a) Unit	(b) Planned Days in test year	(c) Start	(d) Stop
1	Covert 2	30	2/4/2028	3/5/2028
2	Karn 3	48	10/3/2027	11/20/2027
3	Karn 3	28	4/3/2028	4/30/2028
4	Karn 4	28	4/3/2028	4/30/2028
5	Jackson	34	3/28/2028	4/30/2028
6	Ludington 1	43	9/10/2027	10/22/2027
7	Ludington 2	43	9/8/2027	10/20/2027
8	Ludington 3	61	3/1/2028	4/30/2028
9	Ludington 4	355	5/11/2027	4/30/2028

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Generating Unit Availability Projections
May 1, 2027 Through April 30, 2028

Case No.: U-22070
Exhibit No.: A-196 (MEW-2)
Page: 1 of 1
Witness: MEWittbrodt
Date: June 2026

Line No.	(a) Plant	(b) Actual ROR 2021-2025	(c) Projected ROR	(d) Periodic Factor	(e) Projected Availability	(f) Actual NEV 2021-2025
1	Karn 3	32.28%	16.83%	20.82%	65.85%	-$6,848,282
2	Karn 4	22.85%	17.83%	7.67%	75.87%	-$13,010,349
3	Ludington 1	15.14%	7.00%	37.63%	58.01%	$35,724,768
4	Ludington 2	4.46%	7.00%	84.93%	14.01%	$4,641,369
5	Ludington 3	4.06%	7.00%	23.69%	70.97%	$9,707,131
6	Ludington 4	6.30%	7.00%	97.48%	2.35%	$1,235,293
7	Ludington 5	10.32%	7.00%	8.17%	85.40%	$3,815,106
8	Ludington 6	5.18%	7.00%	4.44%	88.87%	$32,254,285
9	Hydros	23.23%	5.03%	3.61%	91.54%	$46,424,120
10	Zeeland CC	5.27%	4.00%	7.67%	88.64%	$258,579,713
11	Zeeland 1A	1.83%	4.00%	1.64%	94.42%	$32,309,283
12	Zeeland 1B	2.13%	4.00%	1.64%	94.42%	$36,570,971
13	Jackson	7.73%	5.50%	1.29%	93.28%	$208,823,034
14	Covert 1 (3)	4.40%	6.00%	4.93%	89.36%	$89,442,877
15	Covert 2 (3)	9.51%	6.00%	10.68%	83.96%	$77,442,744
16	Covert 3 (3)	9.93%	6.00%	3.84%	90.39%	$86,190,196
17	Cross Winds EP					$131,992,575
18	Lake Winds EP					$47,376,175
19	Gratiot Farms Wind(1)					$57,536,392
20	Crescent Wind(1)					$59,279,622
21	Heartland (2)					$27,521,417
22	Solar Gardens					$1,613,326

(1) Reflects NEV for 2022-2025 only.
(2) Reflects NEV for 2023-2025 only.
(3) Reflects NEV for 2023-2025 only.

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-22070
Exhibit No.: A-12 (MEW-3)
Schedule: B-5.2
Page: 1 of 9
Witness: MEWittbrodt
Date: June 2026

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2025 through 2028
($000's)

Generation Capital Expenditures
($000)

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2025	(c) Projected Bridge Period 12 Mos Ended 12/31/2026	(d) Projected Bridge Period 4 Mos Ending 4/30/2027	(e) Projected Bridge Period 16 Mos Ending 4/30/2027	(f) Projected Test Year 12 Mos Ending 4/30/2028
1	Steam Power Generation					
2	Environmental	$ -	$ -	$ -	$ -	$ -
3	Routine and Small CapEx	$ 24,472	$ 13,178	$ 1,033	$ 14,211	$ 3,170
4	Total Steam Production	$ 24,472	$ 13,178	$ 1,033	$ 14,211	$ 3,170
5	Hydraulic Power Generation					
6	Routine and Small CapEx	$ -	$ -	$ -	$ -	$ -
7	Total hydraulic production	$ -	$ -	$ -	$ -	$ -
8	Pumped Storage Generation					
9	Ludington Overhaul	$ -	$ -	$ -	$ -	$ -
10	Routine and Small CapEx	$ 9,843	$ 22,702	$ 6,900	$ 29,603	$ 29,552
11	Total Pumped Storage Generation	$ 9,843	$ 22,702	$ 6,900	$ 29,603	$ 29,552
12	Other Production Plant					
13	Routine and Small CapEx	$ 186,388	$ 169,677	$ 49,916	$ 219,594	$ 130,362
14	Total Other Production Plant	$ 186,388	$ 169,677	$ 49,916	$ 219,594	$ 130,362
15	SubTotal	$ 220,702	$ 205,557	$ 57,850	$ 263,407	$ 163,084
16	Less Contingency	$ -	$ -	$ -	$ -	$ -
17	Grand Total	$ 220,702	$ 205,557	$ 57,850	$ 263,407	$ 163,084

Line No.	(a) Description	(b) Projected 4 Mos Ending 4/30/2026	(c) Projected 12 Mos Ending 4/30/2027	(d) Projected 12 Mos Ending 4/30/2028	(e) Projected 28 Mos Ending 4/30/2028
1	Steam Power Generation				
2	Environmental	$ -	$ -	$ -	$ -
3	Routine and Small CapEx	$ 4,313	$ 9,898	$ 3,170	$ 17,380
4	Total Steam Production	$ 4,313	$ 9,898	$ 3,170	$ 17,380
5	Hydraulic Power Generation				
6	Routine and Small CapEx	$ -	$ -	$ -	$ -
7	Total hydraulic production	$ -	$ -	$ -	$ -
8	Pumped Storage Generation				
9	Ludington Overhaul				$ -
10	Routine and Small CapEx	$ 6,787	$ 22,816	$ 29,552	$ 59,155
11	Total Pumped Storage Generation	$ 6,787	$ 22,816	$ 29,552	$ 59,155
12	Other Production Plant				
13	Routine and Small CapEx	$ 66,429	$ 153,164	$ 130,362	$ 349,956
14	Total Other Production Plant	$ 66,429	$ 153,164	$ 130,362	$ 349,956
15	SubTotal	$ 77,529	$ 185,878	$ 163,084	$ 426,491
16	Less Contingency	$ -	$ -	$ -	$ -
17	Grand Total	$ 77,529	$ 185,878	$ 163,084	$ 426,491

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2025 through 2028
($000's)

Case No.: U-22070
Exhibit No.: A-12 (MEW-3)
Schedule: B-5.2
Page: 2 of 9
Witness: MEWittbrodt
Date: June 2026

Generation Capital Expenditures

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2025	(c)	(d) Projected Bridge Period 12 Months Ending 12/31/2026	(e)	(f) Projected Bridge Period 4 Months Ending 4/30/2027	(g)	(h) Projected Bridge Period 16 Months Ending 4/30/2027	(i)	(j) Projected Test Year 12 Months Ending 4/30/2028	(k)
1	**JHCampbell 1&2**	**$ -**		**$ -**		**$ -**		**$ -**		**$ -**	
2	Contractor		$ -		$ -		$ -		$ -		$ -
3	Labor		$ -		$ -		$ -		$ -		$ -
4	Materials		$ -		$ -		$ -		$ -		$ -
5	Business Expenses		$ -		$ -		$ -		$ -		$ -
6	Contingency		$ -		$ -		$ -		$ -		$ -
7	Other (Loadings, Chargebacks)		$ -		$ -		$ -		$ -		$ -
8	**JHCampbell 3**	**$ -**		**$ -**		**$ -**		**$ -**		**$ -**	
9	Contractor		$ -		$ -		$ -		$ -		$ -
10	Labor		$ -		$ -		$ -		$ -		$ -
11	Materials		$ -		$ -		$ -		$ -		$ -
12	Business Expenses		$ -		$ -		$ -		$ -		$ -
13	Contingency		$ -		$ -		$ -		$ -		$ -
14	Other (Loadings, Chargebacks)		$ -		$ -		$ -		$ -		$ -
15	**DEKarn 1&2**	**$ -**		**$ -**		**$ -**		**$ -**		**$ -**	
16	Contractor		$ -		$ -		$ -		$ -		$ -
17	Labor		$ -		$ -		$ -		$ -		$ -
18	Materials		$ -		$ -		$ -		$ -		$ -
19	Business Expenses		$ -		$ -		$ -		$ -		$ -
20	Contingency		$ -		$ -		$ -		$ -		$ -
21	Other (Loadings, Chargebacks)		$ -		$ -		$ -		$ -		$ -
22	**DEKarn 3&4**	**$ 24,472**		**$ 13,178**		**$ 1,033**		**$ 14,211**		**$ 3,170**	
23	Contractor		$ 17,271		$ 11,521		$ 904		$ 12,424		$ 2,772
24	Labor		$ 934		$ -		$ -		$ -		$ -
25	Materials		$ 2,400		$ 2		$ (0)		$ 2		$ -
26	Business Expenses		$ 9		$ -		$ -		$ -		$ -
27	Contingency		$ -		$ -		$ -		$ -		$ -
28	Other (Loadings, Chargebacks)		$ 3,858		$ 1,655		$ 130		$ 1,784		$ 398
29	**Zeeland**	**$ 49,708**		**$ 32,991**		**$ 16,047**		**$ 49,037**		**$ 52,137**	
30	Contractor		$ 41,780		$ 29,781		$ 14,328		$ 44,109		$ 45,672
31	Labor		$ 319		$ -		$ -		$ -		$ -
32	Materials		$ 1,511		$ 56		$ 17		$ 74		$ 798
33	Business Expenses		$ 2,687		$ -		$ -		$ -		$ -
34	Contingency		$ -		$ -		$ -		$ -		$ -
35	Other (Loadings, Chargebacks)		$ 3,413		$ 3,154		$ 1,701		$ 4,855		$ 5,667
36	**Jackson Generating Station**	**$ 20,760**		**$ 27,905**		**$ 7,439**		**$ 35,343**		**$ 25,733**	
37	Contractor		$ 15,827		$ 25,603		$ 6,936		$ 32,539		$ 23,872
38	Labor		$ 88		$ -		$ 6		$ 6		$ 45
39	Materials		$ 2,665		$ -		$ -		$ -		$ -
40	Business Expenses		$ 11		$ -		$ -		$ -		$ -
41	Contingency		$ -		$ -		$ -		$ -		$ -
42	Other (Loadings, Chargebacks)		$ 2,169		$ 2,302		$ 497		$ 2,798		$ 1,816
43	**Covert**	**$ 42,161**		**$ 73,862**		**$ 14,849**		**$ 88,711**		**$ 47,252**	
44	Contractor		$ 34,119		$ 66,123		$ 13,668		$ 79,791		$ 43,449
45	Labor		$ 323		$ 29		$ 44		$ 73		$ 93
46	Materials		$ 4,204		$ 177		$ 38		$ 215		$ 104
47	Business Expenses		$ (93)		$ -		$ -		$ -		$ -
48	Contingency		$ -		$ -		$ -		$ -		$ -
49	Other (Loadings, Chargebacks)		$ 3,609		$ 7,534		$ 1,099		$ 8,633		$ 3,607

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Generation Capital Expenditures

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2025	(c)	(d) Projected Bridge Period 12 Months Ending 12/31/2026	(e)	(f) Projected Bridge Period 4 Months Ending 4/30/2027	(g)	(h) Projected Bridge Period 16 Months Ending 4/30/2027	(i)	(j) Projected Test Year 12 Months Ending 4/30/2028	(k)
50	**Hydros**	**-**		**-**		**$ -**		**-**		**-**	
51	Contractor		-		-		$ -		-		-
52	Labor		-		-		$ -		-		-
53	Materials		-		-		$ -		-		-
54	Business Expenses		-		-		$ -		-		-
55	Contingency		-		-		$ -		-		-
56	Other (Loadings, Chargebacks)		-		-		$ -		-		-
57	**Ludington**	**9,843**		**22,702**		**$ 6,900**		**29,603**		**29,552**	
58	Contractor		14,239		38,000		$ 11,402		49,402		48,413
59	Labor		823		-		$ -		-		-
60	Materials		2,267		-		$ -		-		-
61	Business Expenses		10		-		$ -		-		-
62	Contingency		-		-		$ -		-		-
63	Other (Loadings, Chargebacks)		(7,497)		(15,297)		$ (4,502)		(19,799)		(18,861)
64	**Admin and Other**	**7,875**		**9,113**		**$ 2,980**		**12,093**		**5,240**	
65	Contractor		3,819		8,740		$ 2,886		11,625		5,084
66	Labor		431		-		$ -		-		-
67	Materials		1,359		-		$ -		-		-
68	Business Expenses		1,492		-		$ -		-		-
69	Contingency		-		-		$ -		-		-
70	Other (Loadings, Chargebacks)		775		374		$ 94		468		156
71	**Battery Storage**	**65,883**		**25,806**		**$ 8,602**		**34,408**		**-**	
72	Contractor		1,100		10,639		$ 3,746		14,386		-
73	Labor		157		-		$ -		-		-
74	Materials		61,076		11,624		$ 3,680		15,304		-
75	Business Expenses		140		-		$ -		-		-
76	Contingency		-		-		$ -		-		-
77	Other (Loadings, Chargebacks)		3,410		3,543		$ 1,176		4,719		-
78	**All Other Environmental**	**-**		**-**		**$ -**		**-**		**-**	
79	Contractor		-		-		$ -		-		-
80	Labor		-		-		$ -		-		-
81	Materials		-		-		$ -		-		-
82	Business Expenses		-		-		$ -		-		-
83	Contingency		-		-		$ -				-
84	Other (Loadings, Chargebacks)		-		-		$ -		-		-
85	**Total Capital**	220,702	220,702	205,557	205,557	57,850	57,850	263,407	263,407	163,084	163,084

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($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
			Projected		
Line No.	**Description**	**4 Mos Ending 4/30/2026**	**12 Mos Ending 4/30/2027**	**12 Mos Ending 4/30/2028**	**28 Mos Ending 4/30/2028**
1	**JHCampbell 1&2**	**$ -**	**$ -**	**$ -**	**$ -**
2	Contractor	$ -	$ -	$ -	$ -
3	Labor	$ -	$ -	$ -	$ -
4	Materials	$ -	$ -	$ -	$ -
5	Business Expenses	$ -	$ -	$ -	$ -
6	Contingency	$ -	$ -	$ -	$ -
7	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
8	**JHCampbell 3**	**$ -**	**$ -**	**$ -**	**$ -**
9	Contractor	$ -	$ -	$ -	$ -
10	Labor	$ -	$ -	$ -	$ -
11	Materials	$ -	$ -	$ -	$ -
12	Business Expenses	$ -	$ -	$ -	$ -
13	Contingency	$ -	$ -	$ -	$ -
14	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
15	**DEKarn 1&2**	**$ -**	**$ -**	**$ -**	**$ -**
16	Contractor	$ -	$ -	$ -	$ -
17	Labor	$ -	$ -	$ -	$ -
18	Materials	$ -	$ -	$ -	$ -
19	Business Expenses	$ -	$ -	$ -	$ -
20	Contingency	$ -	$ -	$ -	$ -
21	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
22	**DEKarn 3&4**	**$ 4,313**	**$ 9,898**	**$ 3,170**	**$ 17,380**
23	Contractor	$ 3,769	$ 8,655	$ 2,772	$ 15,196
24	Labor	$ -	$ -	$ -	$ -
25	Materials	$ 3	$ (0)	$ -	$ 2
26	Business Expenses	$ -	$ -	$ -	$ -
27	Contingency	$ -	$ -	$ -	$ -
28	Other (Loadings, Chargebacks)	$ 542	$ 1,243	$ 398	$ 2,182
29	**Zeeland**	**$ 18,758**	**$ 30,279**	**$ 52,137**	**$ 101,174**
30	Contractor	$ 16,716	$ 27,393	$ 45,672	$ 89,781
31	Labor	$ -	$ -	$ -	$ -
32	Materials	$ -	$ 74	$ 798	$ 871
33	Business Expenses	$ -	$ -	$ -	$ -
34	Contingency	$ -	$ -	$ -	$ -
35	Other (Loadings, Chargebacks)	$ 2,041	$ 2,813	$ 5,667	$ 10,522
36	**Jackson Generating Station**	**$ 9,887**	**$ 25,457**	**$ 25,733**	**$ 61,077**
37	Contractor	$ 8,994	$ 23,545	$ 23,872	$ 56,411
38	Labor	$ -	$ 6	$ 45	$ 51
39	Materials	$ -	$ -	$ -	$ -
40	Business Expenses	$ -	$ -	$ -	$ -
41	Contingency	$ -	$ -	$ -	$ -
42	Other (Loadings, Chargebacks)	$ 892	$ 1,906	$ 1,816	$ 4,615
43	**Covert**	**$ 26,130**	**$ 62,581**	**$ 47,252**	**$ 135,963**
44	Contractor	$ 23,379	$ 56,412	$ 43,449	$ 123,239
45	Labor	$ -	$ 73	$ 93	$ 165
46	Materials	$ 79	$ 136	$ 104	$ 319
47	Business Expenses	$ -	$ -	$ -	$ -
48	Contingency	$ -	$ -	$ -	$ -
49	Other (Loadings, Chargebacks)	$ 2,672	$ 5,961	$ 3,607	$ 12,240

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Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
			Projected		
Line No.	**Description**	**4 Mos Ending 4/30/2026**	**12 Mos Ending 4/30/2027**	**12 Mos Ending 4/30/2028**	**28 Mos Ending 4/30/2028**
50	**Hydros**	**$ -**	**$ -**	**$ -**	**$ -**
51	Contractor	$ -	$ -	$ -	$ -
52	Labor	$ -	$ -	$ -	$ -
53	Materials	$ -	$ -	$ -	$ -
54	Business Expenses	$ -	$ -	$ -	$ -
55	Contingency	$ -	$ -	$ -	$ -
56	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
57	**Ludington**	**$ 6,787**	**$ 22,816**	**$ 29,552**	**$ 59,155**
58	Contractor	$ 11,311	$ 38,090	$ 48,413	$ 97,815
59	Labor	$ -	$ -	$ -	$ -
60	Materials	$ -	$ -	$ -	$ -
61	Business Expenses	$ -	$ -	$ -	$ -
62	Contingency	$ -	$ -	$ -	$ -
63	Other (Loadings, Chargebacks)	$ (4,525)	$ (15,275)	$ (18,861)	$ (38,660)
64	**Admin and Other**	**$ 3,053**	**$ 9,041**	**$ 5,240**	**$ 17,333**
65	Contractor	$ 2,896	$ 8,729	$ 5,084	$ 16,709
66	Labor	$ -	$ -	$ -	$ -
67	Materials	$ -	$ -	$ -	$ -
68	Business Expenses	$ -	$ -	$ -	$ -
69	Contingency	$ -	$ -	$ -	$ -
70	Other (Loadings, Chargebacks)	$ 157	$ 311	$ 156	$ 624
71	**Battery Storage**	**$ 8,602**	**$ 25,806**	**$ -**	**$ 34,408**
72	Contractor	$ 4,390	$ 9,996	$ -	$ 14,386
73	Labor	$ -	$ -	$ -	$ -
74	Materials	$ 1,377	$ 13,927	$ -	$ 15,304
75	Business Expenses	$ -	$ -	$ -	$ -
76	Contingency	$ -	$ -	$ -	$ -
77	Other (Loadings, Chargebacks)	$ 2,835	$ 1,884	$ -	$ 4,719
78	**All Other Environmental**	**$ -**	**$ -**	**$ -**	**$ -**
79	Contractor	$ -	$ -	$ -	$ -
80	Labor	$ -	$ -	$ -	$ -
81	Materials	$ -	$ -	$ -	$ -
82	Business Expenses	$ -	$ -	$ -	$ -
83	Contingency	$ -	$ -	$ -	$ -
84	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
85	**SubTotal**	$ 77,529	$ 185,878	$ 163,084	$ 426,491
86	**Less Contingency**	$ -	$ -	$ -	$ -
87	**Grand Total**	$ 77,529	$ 185,878	$ 163,084	$ 426,491

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Generation Capital Expenditures

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2025	(c) Projected Bridge Period 12 Months Ending 12/31/2026	(d) Projected Bridge Period 4 Months Ending 4/30/2027	(e) Projected Bridge Period 16 Months Ending 4/30/2027	(f) Projected Test Year 12 Months Ending 4/30/2028
1	Contractor	$ 128,154	$ 190,406	$ 53,870	$ 244,276	$ 169,261
2	Labor	$ 3,074	$ 29	$ 50	$ 79	$ 138
3	Materials	$ 75,483	$ 11,859	$ 3,735	$ 15,594	$ 901
4	Business Expenses	$ 4,256	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 9,735	$ 3,264	$ 195	$ 3,458	$ (7,216)
	Total	$ 220,702	$ 205,557	$ 57,850	$ 263,407	$ 163,084

Line No.	(a) Description	(b) 12 Months Ended 12/31/2025	(c) 4 Months Ending 4/30/2026	(d) Projected 16 Months Ending 4/30/2027	(e) 12 Months Ending 4/30/2028	(f) 28 Months Ending 4/30/2028
1	Contractor	$ 128,154	$ 71,455	$ 244,276	$ 169,261	$ 413,537
2	Labor	$ 3,074	$ -	$ 79	$ 138	$ 216
3	Materials	$ 75,483	$ 1,459	$ 15,594	$ 901	$ 16,496
4	Business Expenses	$ 4,256	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 9,735	$ 4,615	$ 3,458	$ (7,216)	$ (3,758)
	Total	$ 220,702	$ 77,529	$ 263,407	$ 163,084	$ 426,491

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Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Work Item Description	(g) Projected Amount	(h) Actual Amount
1	2025	Gas Generation	Covert	Routine	Condition-based	Units 1-3 Emerson DCS Evergreen	$2,589	$1,117
2	2025	Gas Generation	Covert	Routine	Condition-based	Long Term Service Agreement - Running capital contrac	$34,196	$29,790
3	2025	Gas Generation	Covert	Routine	Condition-based	Netmation (MHPSA Operating System & 4S) - Units 1-3	$2,631	$2,918
4	2025	Gas Generation	Covert	Non-Routine	Condition-based	CGS Main Steam Tee Header Replacements	$0	$1,656
5	2025	Gas Generation	Jackson	Routine	Condition-based	GE Long Term Service Agreement FFH	$15,073	$8,972
6	2025	Gas Generation	Jackson	Routine	Condition-based	LTSA Capital - Extra work not included in contrac	$3,472	$7,456
7	2025	Gas Generation	Jackson	Non-Routine	Economic	JGS-LM1-6 VIGV-variable inlet guide vane	$0	$1,507
8	2025	Gas Generation	Zeeland	Routine	Condition-based	LTSA - Extras not included in contract (cranes, mobile equipment	$2,795	$1,757
9	2025	Gas Generation	Zeeland	Non-Routine	Condition-based	Unit 5 GSU Transformer Rewind	$3,743	$3,786
10	2025	Gas Generation	Zeeland	Routine	Condition-based	Zeeland GE LTSA Pmts - Unit 1A	$0	$14,731
11	2025	Gas Generation	Zeeland	Routine	Condition-based	Zeeland GE LTSA Payments - Unit 1B	$0	$14,748
12	2025	Gas Generation	Zeeland	Routine	Condition-based	Zeeland GE LTSA Pmts -Combine Cycle	$0	$11,748
13	2025	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Combustion Air Heater Replacement	$3,122	$2,742
14	2025	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Karn 4 Transformer Fire Capital	$0	$2,304
15	2025	Gas/Oil Generation	Karn 3 & 4	Non-Routine	Condition-based	KARN 3&4 BOILER PLANT HEATING	$0	$1,193
16	2025	Gas/Oil Generation	Karn 3 & 4	Non-Routine	Condition-based	Karn 3&4 Separation Assets	$0	$14,215
17	2025	Hydro Generation	Ludington	Non-Routine	Condition-based	Ludington 1-6 DCS Control Relay Replacemen	$2,242	$1,461
18	2025	Hydro Generation	Ludington	Non-Routine	Condition-based	Ludington Governor Replacement	$3,189	$1,151
19	2025	Hydro Generation	Ludington	Non-Routine	Condition-based	Replace Lower Penstock Expansion Joint	$2,758	$1,720
20	2025	Hydro Generation	Ludington	Non-Routine	Condition-based	LPS U2&U4 Head Cover & Bottom Ring Repl	$0	$3,091
21	2025	Admininstration	Admin	Non-Routine	Condition-based	Generation - IT/Cyber Security Capita	$0	$1,719
22	2025	Admininstration	Admin	Non-Routine	Environmental	Wastewater Treatment System	$12,420	$2,498
23	2025	Admininstration	Admin	Non-Routine	Infrastructure	Lakeshore Admin Building	$3,090	$2,661
24	2025	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Iosco Battery Energy Storage System (IRP)	$34,819	$26,991
25	2025	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Weadock Battery Energy Storage System (IRP)	$33,934	$35,458
26	**Total 2025 Projects**						**$ 160,074**	**$ 197,390**

Note:
(1) Projected amounts were taken from Case No. U-21870, Staff Exhibit S-8.1 Page 1 of 2 and workpapers.

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Line No.	(a) Calendar Period	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Class of Cost Estimate	(f) Full Internal Budget Approval	(g) Work Item Description	(h) Projected Amount
1	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	Unit 1 - LTSA Capital - Owner Obligations Cap Portion	$9,024
2	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	Unit 3 - LTSA Capital - Owner Obligations Cap Portion	$11,513
3	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 2	Approved	U1-3 Circ water pumps replacements	$1,581
4	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	COVERT LONG TERM SERVICE AGREEMENT	$26,813
5	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 1	Approved	Covert Spare GSU	$4,546
6	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 1	Approved	Netmation(MHPSA Operating System)	$7,647
7	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	DCS Evergreen Replacement	$1,452
8	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 1	Approved	LCI Replacements (SFC)	$3,021
9	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 1	Approved	Main Steam Tee Header Replacements	$5,455
10	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 2	Approved	U 1,2,3 NERC Relay Replacements	$1,514
11	Bridge Period	Gas Generation	Jackson	Non-Routine	Condition-based	Class 2	Approved	JGS Unit 7 Gas Turbine Rotor Replacement	$2,127
12	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	LTSA spend with GE	$17,010
13	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	GE LTSA Historical Owner Obligations Cap Portion	$7,237
14	Bridge Period	Gas Generation	Jackson	Non-Routine	Economic	Class 1	Approved	LM1-6 VIGV-variable inlet guide vane	$1,274
15	Bridge Period	Gas Generation	Jackson	Non-Routine	Condition-based	Class 3	Approved	Generator Step Up Transformer (GSU)	$1,160
16	Bridge Period	Gas Generation	Zeeland	Non-Routine	Economic	Class 1	Approved	Phase II Turbine Replacements	$10,330
17	Bridge Period	Gas Generation	Zeeland	Non-Routine	Economic	Class 1	Approved	Phase II GT Advanced gas path replacement and axial fuel staging	$14,622
18	Bridge Period	Gas Generation	Zeeland	Routine	Condition-based	Class 1	Approved	GE LTSA Pmts - Unit 1A	$12,364
19	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	PH 1 & PH 2 High Recovery Gas Valves	$3,168
20	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Site Spare GSU	$4,585
21	Bridge Period	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 2	Approved	Karn 3 CAH replacement	$2,250
22	Bridge Period	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 2	Approved	Karn 4 ID Fan Inlet Damper Replacement	$2,025
23	Bridge Period	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 2	Approved	Karn 4 Transformer Fire Capital	$4,296
24	Bridge Period	Gas/Oil Generation	Karn Commons	Non-Routine	Condition-based	Class 3	Approved	Karn 3&4 Ductwork Expansion Joint	$2,358
25	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	480V MCC for DLC	$1,922
26	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 2	Approved	DCS Control Relay Replacement	$4,302
27	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 2	Approved	Governor Replacement	$3,095
28	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Pony Motor Rotor Replacement	$3,870
29	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 2	Approved	U2&U4 Head Cover & Bottom Ring Repl	$5,676
30	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 2	Approved	LPS Intake Gate & Gate House	$1,516
31	Bridge Period	Hydro Generation	Ludington	Routine	Condition-based	Class 2	Approved	Station Power Trnsfrmr Life Cyc Mgmt	$1,380
32	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 2	Approved	LPS Admin Building	$3,500
33	Bridge Period	Admininstration	Admin	Non-Routine	Condition-based	Class 2	Approved	JHC Wastewater Treatment System	$10,517
34	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 1	Approved	Iosco Battery Energy Storage System (IRP)	$13,558
35	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 1	Approved	Weadock Battery Energy Storage System (IRP)	$21,841
36	**Total Bridge Period Projects**								**$228,549**

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2025 through 2028
($000's)

Case No.: U-22070
Exhibit No.: A-12 (MEW-3)
Schedule: B-5.2
Page: 9 of 9
Witness: MEWittbrodt
Date: June 2026

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Class of Cost Estimate	(g) Full Internal Budget Approval	(h) Work Item Description	(i) Projected Amount
1	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Class 3	Approved	Plant Replace Sulfuric Sodium Hypo and Building	$1,234
2	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	Unit 1 - LTSA Capital - Owner Obligations Cap Portion	$3,390
3	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	Covert Long Term Service Agreement	$23,094
4	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Class 2	Approved	Spare GSU	$8,684
5	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Class 2	Approved	U1-3 Circ water pumps replacements	$2,035
6	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Class 1	Approved	LCI Replacements (SFC)	$1,749
7	Test Year	Gas Generation	Jackson	Non-Routine	Condition-based	Class 2	Approved	Main and Aux Cooling Tower Rebuilds	$2,308
8	Test Year	Gas Generation	Jackson	Non-Routine	Condition-based	Class 2	Approved	JGS Unit 7 Gas Turbine Rotor Replacement	$1,495
9	Test Year	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	LTSA spend with GE	$13,451
10	Test Year	Gas Generation	Jackson	Non-Routine	Condition-based	Class 2	Approved	Generator Step Up Transformer (GSU)	$2,000
11	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	Phase II Turbine Replacements	$12,027
12	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	Phase II GT Advanced gas path replacement and axial fuel staging	$18,052
13	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	ST 2C Field Exchange and Generator Major Overhaul	$1,734
14	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Main Steam & Hot Reheat Isolation Valves Replacement	$1,050
15	Test Year	Gas Generation	Zeeland	Routine	Condition-based	Class 1	Approved	GE LTSA Pmts - Unit 1A	$9,575
16	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	ZGS PH1 & PH2 High Recovery Gas Valves	$1,080
17	Test Year	Gas Generation	Zeeland	Routine	Condition-based	Class 1	Approved	LTSA Owner Obligations	$3,498
18	Test Year	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 2	Approved	Karn 4 Combustion air heater replacement	$2,733
19	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	480V MCC for DLC	$1,558
20	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	DCS Control Relay Replacement	$2,132
21	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 2	Approved	LPS Governor Replacement	$2,560
22	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Pony Motor Rotor Replacement	$3,270
23	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 2	Approved	U2&U4 Head Cover & Bottom Ring Replacement	$9,900
24	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 2	Approved	LPS Admin Building	$5,400
25	Test Year	Admininstration	Admin	Non-Routine	Condition-based	Class 2	Approved	JHC Wastewater Treatment System	$4,167
26	**Total Test Year Projects**								**$138,174**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected Generation O&M Expenses
For the Historical Year (2025) and Test Year 5/1/2027 - 4/30/2028
($000)

Case No.: U-22070
Exhibit No.: A-197 (MEW-4)
Page: 1 of 3
Witness: MEWittbrodt
Date: June 2026

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2025	(c) Projected 12-Mos Ending 4/30/2028
1	Base O&M	72,970	66,180
	Labor	49,554	47,589
	Material	2,768	2,559
	Contractor	4,285	15,813
	Non-Labor Overhead	(120)	422
	Non-Labor Other	16,483	(203)
2	Major Maintenance	33,348	33,727
	Labor	954	-
	Material	3,294	-
	Contractor	25,884	33,580
	Non-Labor Overhead	328	147
	Non-Labor Other	2,889	-
3	Environmental Operations	5,089	2,575
	Labor	2,417	1,223
	Material	290	147
	Contractor	1,444	731
	Non-Labor Overhead	10	5
	Non-Labor Other	927	469
4	Retention & Separation	-	-
	Labor		
	Material		
	Contractor		
	Non-Labor Overhead		
	Non-Labor Other		
5	Total Generation O&M Expenses	111,407	102,482
6	Labor	52,925	48,812
7	Material	6,352	2,706
8	Contractor	31,613	50,124
9	Non-Labor Overhead	217	574
10	Non-Labor Other	20,300	266

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
For the Historical Year (2025) and Test Year 5/1/2027 - 4/30/2028
($000)

Case No.: U-22070
Exhibit No.: A-197 (MEW-4)
Page: 2 of 3
Witness: MEWittbrodt
Date: June 2026

Line No.	(a) Description	(b) Actual 12 Mos Ending 12/31/2025	(c) Inflation Applied to Projected Test Year (b) * Compounded Inflation Rate	(d) Other Adjustments	(e) Projected O&M 12 Mos Ending 4/30/2028 (b) + (c) + (d)
1	Base O&M	$ 72,970	$ 4,558	$ (11,347)	$ 66,180
2	Major Maintenance	$ 33,348	$ 2,083	$ (1,704)	$ 33,727
3	Environmental Operations	$ 5,089	$ 318	$ (2,832)	$ 2,575
4	Retention & Separation	$ -	$ -	$ -	$ -
5	Total Generation O&M Expenses	111,407	6,958	(15,883)	102,482

Notes

	12-Mo Ending 2026	12-Mo Ending 2027	4-Mo Ending 2028	Compounded Inflation Rate
Annual inflation rates per Company witness Patton	2.9%	2.5%	2.2%	7.8%
Number of months in the period	12	12	4	
Pro-rated inflation rate	2.9%	2.5%	0.7%	6.2%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of the Generation O&M Expense
For the Years 2025 through April 2028
($000's)

Case No.: U-22070
Exhibit No.: A-197 (MEW-4)
Page: 3 of 3
Witness: MEWittbrodt
Date: June 2026

GENERATION MAJOR MAINTENANCE EXPENSES

Line No.	(a) Description		(b) Historical 12 Months Ended 12/31/2025	(c) Projected Test Year 12 Months Ending 04/30/2028
	Major Maintenance			
1	Campbell 1&2		$ 64	$ -
2	Campbell 3		$ 153	$ -
3	Karn 1&2		$ -	$ -
4	Karn 3&4		$ 6,153	$ 1,321
5	Classic 7	#	$ 82	$ 218
6	Zeeland Generating Station	#	$ 5,542	$ 7,318
7	Jackson Generating Station		$ 5,565	$ 5,587
8	Covert Generating Stations		$ 8,001	$ 6,081
9	Ludington		$ 3,345	$ 5,963
10	Hydros		$ 4,442	$ 6,963
11	Battery		$ -	$ 126
12	Admin & Other		$ -	$ 150
13	**TOTAL Major Maintenance**		**$ 33,348**	**$ 33,727**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual Coal Ash Disposal Plan Expenditures
($000's)

Case No.: U-22070
Exhibit No.: A-198 (MEW-5)
Page: 1 of 1
Witness: MEWittbrodt
Date: June 2026

	Site	Actuals 2025
(a)	**DE Karn**	$ 16,313
(b)	**JC Weadock**	$ 2,440
(c)	**BC Cobb**	$ 842
(d)	**JR Whiting**	$ 69
(e)	**JH Campbell**	$ 12,677
(f)	**Total**	$ 32,341

Concept Approval

Covert Station Static Frequency Converter Replacement

Date: 9/24/2024

Prepared by: Paul Ohep



Figure 1. Covert Generating Station

Executive Summary

The Covert Generating Station (CGS) Static Frequency Converter (SFC) Controls Replacement project addresses critical operational and reliability issues due to the obsolescence of the current SFC controls. This project is essential for maintaining the operational integrity and reliability of the plant's turbine generators, which rely on the SFCs for startup.

Problem Description: The existing SFC controls, which are nearly 25 years old, pose a high risk of failure. Engineering estimates indicate a 30% failure probability for these electronic components, increasing by 15% annually. The failure of both SFCs would prevent the startup of any unit at CGS, resulting in a total operational shutdown and significant financial losses. Mitsubishi, the Original Equipment Manufacturer (OEM), strongly recommends replacing the controls and other obsolete components, highlighting the urgency of this project.

Alternative Solutions:

1. **Do Nothing**: This option poses significant risks, including a potential $125,884,384 financial impact due to forced outages and capacity losses. The high probability of failure of the obsolete controls could result in prolonged outages, severely impacting the plant's operational integrity and financial stability.
2. **Replace Controls on Both SFCs During 2026 All-Unit Outage**: This option eliminates the immediate risk of failure, restores system reliability, and saves costs by performing both replacements simultaneously during the planned 2026 outage. The estimated cost is $4,466,000.
3. **Replace Controls on One SFC in 2026 and the Second in 2032**: This phased approach mitigates some immediate risks but retains reliance on aging controls until 2032. It incurs higher overall costs ($6,185,000) and repeated operational disruptions, increasing the risk of failures and financial losses.

Selected Option Justification: Chosen Option: Alternative 2 – Replace both SFC controls and obsolete equipment during the 2026 all-unit outage.

Rationale for Selection: Alternative 2 is the lowest cost and most risk-averse option, addressing critical obsolescence issues comprehensively. This approach ensures the reliability of the SFC system until the plant's anticipated closure.

Conclusion: Replacing the controls on both SFCs during the 2026 all-unit outage is the most prudent and cost-effective approach. It comprehensively addresses the critical obsolescence issues, restores system reliability, and aligns with the planned maintenance schedule, minimizing operational risks and ensuring the plant's continued efficiency and reliability.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$5,000,000

Proposed Start Implementation Year and Duration

Implementation Year: 2026

Problem Description

Project Overview

The Covert Generating Station (CGS) Static Frequency Converter (SFC) Controls Replacement project is essential to address significant operational and reliability issues stemming from the obsolescence of the current SFC controls. This project is critical for maintaining the operational integrity and reliability of the plant's turbine generators, which rely on the SFCs for startup.

Background

To initiate the combustion turbine at CGS, the attached generator is used as a motor to start spinning the turbine generator train. The Static Frequency Converter provides variable power to the generator stator, enabling this startup process. The SFC system includes a converter, a DC reactor, and an inverter, controlled by a generator position sensor to ensure smooth acceleration and prevent overheating of the generator windings.

The plant operates with two SFCs, SFC #1 and SFC #2, both original to the plant's construction in 2001. These converters are connected to all three gas turbine generators at the site. The current system relies on visual inspections during outages to monitor overheating, which is insufficient for proactive maintenance.

Necessity for Replacement

The necessity for replacing the SFC controls arises from their advanced age and increasing risk of failure. Key points include:

- **Obsolescence and Risk of Failure**: The SFC controls are nearly 25 years old, and the probability of failure for electronic components increases significantly over decades of use. Engineering estimates indicate a 30% failure probability for any of the 20+ year old electronic components, with this probability increasing by 15% annually. The high risk of failure is due to the nature of aging electronics, which are prone to degradation over time.
- **Operational Impact**: If one SFC fails, the plant can rely on the second SFC. However, if both SFCs fail, the plant will be unable to start any unit, resulting in a complete operational shutdown. Given the critical role of the SFCs in plant operations, their failure poses a substantial risk.
- **Lead Time for Repairs**: In the event of a controls failure, an SFC could be out of service for over a year due to the long lead time for obtaining replacement parts. During this period, the second SFC, which shares the same risk of failure, could also fail, leading to a total inability to start any units at CGS.
- **Vendor Recommendations**: Mitsubishi, the Original Equipment Manufacturer (OEM), strongly recommends replacing the controls and other obsolete components (such as cooling fans), which are no longer serviceable. This recommendation highlights the urgency and necessity of the replacement project.
- **Scheduled Outages**: Replacing the SFC controls requires an all-unit outage of sufficient duration (20 days) to ensure worker protection and complete the work. These outages are scheduled roughly every six years, with the next planned outages in 2026, 2032, and

2038. Coordinating the replacement with the 2026 outage minimizes disruption and ensures continued reliability.

In summary, the replacement of the SFC controls is imperative to mitigate the significant risk of failure due to obsolescence, ensure operational reliability, and align with manufacturer recommendations.

Alternative Solutions/Alternatives Considered

1. Do Nothing – Potential costs up to $125,884,384.

Choosing the "do nothing" option for the Covert Generating Station (CGS) Static Frequency Converter (SFC) Controls Replacement project means maintaining the status quo despite the known obsolescence issues and high risk of failure. This section outlines the potential consequences, including derates, forced outages, and financial impacts, of not executing the replacement project.

Derate and Outage Impacts

- **Derate in MW**: If the SFC controls fail and neither SFC is operational, there would be a total derate of 1289 MW. This includes the inability to start up:
    - Three gas turbines at 282.2 MW each.
    - Three steam turbines at 147.39 MW each.
- **Duration of Derate/Outage**:
    - The initial failure of one SFC would lead to a minimum site-wide, two-week forced outage. This is necessary to disconnect and test other equipment connected to the SFC (such as generators and exciters) to ensure they remain functional, and to re-arrange the bus work so the plant can continue operating with the working SFC while repairs are made to the failed one.
    - Mitsubishi has indicated that given the obsolescence nature of the system the lead time for new controls exceeds one year. During this period, the second SFC is at risk of failing from the same cause, which would prevent the start-up of any units at CGS and extend the outage indefinitely until parts are procured and installed.

Risks of Failure

- **Probability and Consequences**:
    - Engineering estimates indicate a 30% failure probability for any of the 20+ year old electronic components, with this probability increasing by 15% annually.
    - If both SFCs fail, no units at CGS can start, resulting in a complete operational shutdown.

Financial Risk - $7,791,000 for a single SFC failure, $125,884,384 for dual SFC failure

- **Net Energy Value (NEV) losses**:
    - **One SFC failure**: It is expected that this failure will cause a two-week forced outage for all three units, resulting in a reduction of power supply by 1,289 megawatts. This case assumes the outage to take place during the first two weeks of July, which is the same time as the yearly highest demand for power, representing a scenario with the most challenging conditions. The energy value losses calculated for this scenario are estimated to be $**1,280,000** per unit or $**3,840,000** for the entire site.

- **Dual SFC failure**: A one-year forced outage is assumed for this case. The station would then incur a loss of **$7,961,461** per unit or **$23,884,384** for the entire site (all three units).

  The gas prices used the economic model are based on the 2024 0+12 commodity price outlook model.

- **Potential Capacity losses**: Based on the analysis provided by the forecasting group at Consumers Energy, the potential capacity losses for not proceeding with the SFC controls replacement project are quantified for both the one SFC failure scenario and for both SFC failing:

  - **One SFC failure**: A two-week forced outage is assumed for this case. The station would incur a loss of **4.6 Zonal Resource Credits (ZRCs)** per unit annually for three years. This loss translates to a financial impact of approximately **$439K per year per unit or $1,317,000 for the site**, culminating in a total loss of **$3,951,000** over the three-year period for the entire site (all three units). This calculation is based on 4.6 ZRCs multiplied by 75% of $127K (the Cost of New Entry), a benchmark figure representing the hypothetical cost to build a new power plant.

  - **Dual SFC failure:** In a more severe scenario where the CGS loses its full capacity for an entire year due to both SFCs failing, the financial repercussions are even more pronounced. The loss is estimated at 75% of the CONE multiplied by 360MW (nameplate capacity per unit), amounting to **$34 million per unit or $102 million for the entire site**.

  - The Midcontinent Independent System Operator (MISO) capacity pricing rules dictate that utilities must maintain a certain level of capacity to ensure grid reliability. ZRCs are a measure of this capacity, and their loss indicates a shortfall in the utility's ability to meet demand, potentially leading to penalties and reduced revenue. The CONE is used to set capacity prices in the market, and the percentage applied (75% in this case) reflects the proportion of this cost considered in financial calculations, often influenced by regulatory guidelines or market conditions.

Timing of Derate or Forced Shutdown

- The timing of the derate or forced shutdown is irrelevant in this case because the plant cannot start without at least one functional SFC. The operational impact would be severe regardless of the season, as the SFCs are critical for startup operations year-round.

Conclusion

In summary, the "do nothing" option poses significant risks to the operational integrity and financial stability of the Covert Generating Station. The high probability of failure of the obsolete SFC controls, coupled with the extended lead times for replacement parts, could result in prolonged outages and substantial financial losses. This quantifiable risk justifies the need for proactive replacement of the SFC controls to ensure continued reliability and efficiency of plant operations.

Option 2: Replace Controls on Both SFCs During All Unit outage in 2026 – Cost: $5,000,000 (internal loaded estimate)

Alternative 2 proposes replacing the controls on both Static Frequency Converters (SFCs) during the planned all-unit outage in 2026. This approach presents the lowest risk by taking advantage of the scheduled outage to address the obsolescence issues comprehensively, ensuring the reliability of the SFC system until the anticipated plant closure.

Benefits

- **Reduced Risk**: By replacing the controls on both SFCs simultaneously, this option eliminates the immediate and growing risk of failure associated with the aging and obsolete controls. It addresses the critical vulnerability of relying on outdated electronic components that have a high probability of failure.
- **Cost Savings**: Performing the replacements during a planned outage allows for cost efficiencies. Mobilizing once for both replacements reduces labor, transportation, and other logistical expenses. The estimated loaded cost for replacing the controls on both SFCs is $5,000,000 (internal estimate based on Turnkey quote from Vendor).
- **Enhanced Reliability**: Upgrading both SFC controls ensures the plant can reliably start its units without the risk of unexpected failures. This proactive maintenance will restore the SFC system's reliability, supporting stable operations until the plant's anticipated closure.
- **Efficiency and Coordination**: Utilizing the 2026 outage for this replacement aligns with the plant's maintenance schedule, minimizing disruption.

Conclusion

Replacing the controls on both SFCs during the 2026 all-unit outage is the most prudent and cost-effective approach. It addresses the critical obsolescence issues, restores system reliability, and aligns with the planned maintenance schedule, thereby minimizing operational risks and ensuring the plant's continued efficiency and reliability.

Option 3: Replace Controls on One SFC During 2026 All-Unit Outage, Then Wait Until 2032 to Replace the Second SFC Controls – Cost $6,185,000

Alternative 3 involves a phased approach where the controls for one Static Frequency Converter (SFC) are replaced during the all-unit outage in 2026, with the second SFC controls being replaced during the next scheduled outage in 2032. While this option addresses some of the immediate risks associated with the obsolescence of the SFC controls, it retains reliance on the aging system for an extended period, which may compromise reliability and increase costs over time.

Benefits

- **Reduced Immediate Risk**: Replacing the controls on one SFC during the 2026 outage mitigates some of the risk associated with the current obsolete controls, ensuring at least one SFC is updated and reliable.
- **Staggered Investment**: This approach spreads the financial burden over two planned outages, potentially easing the immediate capital expenditure.

Drawbacks

- **Continued Reliability Risks**: By delaying the replacement of the second SFC controls until 2032, the plant remains dependent on the aging and increasingly unreliable controls for another six years. Given the failure probabilities detailed in the problem statement and do-nothing sections, we expect a failure sometime before 2032. This means the site will likely face a forced two-week outage just to check all other connected equipment and align the remaining SFC to the second unit, assuming the new upgraded system is compatible with the existing components. This shutdown would result in considerable losses in Net Energy Value and potential capacity, as detailed in the "Do Nothing" section.
- **Repeated Costs and Efforts**: This option incurs repeated mobilization and logistical costs associated with conducting two separate replacement projects. The total anticipated cost for both replacements is $6,185,000, which is higher than replacing both controls simultaneously in 2026.
- **Potential Cost Escalation**: Delaying the replacement of the second SFC controls exposes the project to potential cost increases due to inflation and changes in market conditions over the next six years.
- **Operational Disruptions**: Each replacement phase requires an all-site outage, leading to repeated operational disruptions and potential loss of productivity.

Conclusion

While Alternative 3 offers a phased approach to spreading the cost over two outages, it introduces significant risks and additional costs. The continued reliance on obsolete controls until 2032 increases the likelihood of failures and operational disruptions. The overall cost of $6,185,000 is higher compared to replacing both controls simultaneously in 2026. This option

presents a higher risk and less cost-effective solution compared to Alternative 2, which provides a comprehensive and more reliable approach to addressing the obsolescence issues at CGS.

Recommended Alternative: #2 Replace both SFC controls and obsolete equipment.

Rationale for Selection

Alternative 2 has been selected for implementation as it represents the lowest cost and most risk-averse option. This approach ensures the reliability and operational integrity of the Static Frequency Converters (SFCs) at Covert Generating Station by addressing their obsolescence comprehensively during the planned all-unit outage in 2026.

Outcomes and Benefits

Outcomes:

1. **Planned Restoration of Reliability**: Both SFCs will have their controls replaced by the end of 2026, addressing obsolescence before failure occurs.
2. **Replacement of Problematic Speed Sensor**: The historically troublesome speed sensor will be replaced, eliminating startup delays that currently range from 1-4 hours per instance.
3. **Testing of Aged Power Cable**: The aged power cables of the SFCs will be tested to verify their reliability through the end of the plant's life.

Benefits:

1. **System Reliability**: Restores the entire SFC system to a reliable state from its current obsolete condition by 2026.
2. **Cost Efficiency**: Utilizing the same craft and engineers for both SFC replacements simultaneously saves costs compared to mobilizing separately for each unit.
3. **Operational Efficiency**: Performing the replacements at the same time minimizes disruption and leverages the planned outage effectively, ensuring reliability through the end of the plant's life.
4. **Error Mitigation**: Avoids the potential for errors associated with staggering the replacements, as the same team will work on both units, maintaining consistency and reducing execution risk.

Highlighted Benefits Over Other Alternatives

The main benefit of Alternative 2 is the comprehensive restoration of reliability to both SFCs by 2026, ensuring continuous operation through the plant's lifecycle. This approach avoids the significant risks and higher costs associated with Alternative 3, which involves staggering the replacements and potentially facing a forced outage due to the high probability of failure in the remaining obsolete controls.

Working on both SFCs during the 2026 outage not only provides cost savings by avoiding repeated mobilization but also ensures that the replacements are handled by the same team, enhancing consistency, and reducing the risk of errors. This approach mitigates the operational risks and financial losses that could occur with a phased replacement strategy, ultimately providing a more secure and cost-effective solution for maintaining the plant's reliability and efficiency.

Scope of work

1. **Preparation (2025-2026)**:
    - Engineering and project management activities will begin in 2025 to ensure all necessary plans, parts, and personnel are in place for the 2026 outage.
    - Coordination with Mitsubishi and other vendors to secure parts and finalize the replacement schedule.
2. **Execution (2026)**:
    - During the all-unit outage in 2026, the existing SFC controls will be removed, and new controls will be installed.
    - Testing and commissioning of the new controls will be conducted to ensure seamless integration and operation.
3. **Closeout (2026)**:
    - Final inspections and closeout activities will be completed to confirm the successful implementation of the project.
    - Documentation and reporting will be finalized to capture all aspects of the replacement for future reference and compliance.

Funding and Timing

- A planned outage is required for this project.
- Desired implementation year:
    - First year spend: 2024
    - Implementation: 2026

System Engineer

- System Engineer: Keith Grzegorczyk

Conceptual Estimate

Year	Loaded Cost	Description
2024	**$130,000**	Generation Planning places retrieves quote and places PO for very long lead time parts.
2025	**$520,000**	EPM starts drawing engineering, outage scheduling, and labor PO.
2026	**$4,350,000**	Parts receipt, construction, and closeout.

Total Cost: $ 5,000,000

Asset Strategy Approval Comments

This project at the Covert Generating Station **is** recognized in the 2023 electric rate case, not as a standalone item but within the broader category of non-LTSA (Long Term Service Agreement) projects. This categorization reflects the strategic allocation of funds for various essential undertakings at Covert, following its recent acquisition.

The allocated budget under work item 1218, titled “Covert -Non LTSA Capital - Extras not included in contract,” encompasses this and other similar projects. The figures covered under this line item are as follows:

Amount set for Bridge year: $ 3,943,000

Amount set for test period: $ 5,510,000

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

Consumers Energy Count on Us®

Concept Approval

Covert Generating Station Generator Step-Up transformer replacement.

Date: 12/1/2023

Prepared by: John Slinkard and Paul Ohep



Figure 1. Covert Generating Station aerial view.

Executive Summary

Addressing the critical need for operational reliability at Consumers Energy's power generation facilities, this proposal explores the optimal strategy for ensuring a backup Generator Step-Up (GSU) transformer is readily available at Covert Generating Station. The urgency of this project stems from the increased risk of transformer failure due to the presence of corrosive sulfur, coupled with long procurement lead times of 2 to 4 years for GSU transformers.

Four options were meticulously evaluated: overhauling the existing GSU, procuring a new site-specific spare GSU, exploring leasing alternatives, and purchasing a single larger spare GSU that could serve both Covert Generating Station and Zeeland Generating Station.

Option 2, which proposes the procurement of a site-specific spare GSU, has emerged as the most viable solution. It ensures immediate availability of a replacement transformer, minimizing downtime and associated financial losses. This option mitigates potential complications arising from multiple installations associated with utilizing a leased GSU or usage of multi-site transformer. Moreover, it also offers the opportunity for CE to recover some costs through leasing agreements with other utilities.

This initiative, backed by the Asset Strategy Group, ensures that Covert Generating Station is equipped to address transformer failures swiftly and efficiently. Implementing this solution safeguards our ability to deliver reliable power to our consumers and demonstrates a strategic foresight in asset management.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$16,355,000

Proposed Start Implementation Year

2024

Project Span Whole Years

4 Years

Problem Description

The Covert Generating Station features a combination of three gas turbine-powered plants and three steam turbine-powered plants, arranged in a one-on-one combined cycle configuration. This setup entails that each gas turbine unit powers the secondary winding of a three-winding transformer (GSU), while the corresponding steam-powered unit powers the tertiary winding.

GSU Explained: A Generator Step-Up (GSU) transformer is a critical component that steps up the voltage generated by a turbine before it is transmitted to the grid, ensuring efficient power transfer.

A GSU's failure can lead to significant power generation issues. Specifically, the GSUs at Covert are rated for 500 MVA and are equipped with forced oil and forced air cooling mechanisms. If a GSU were to fail, both the gas and steam turbine units connected to it would be unable to transmit power, leading to a potential loss of up to 400 MVA of generation capacity. This would prevent the generation of market value for Consumers Energy and its customers.

Further complicating the situation is the long lead time of 2 to 4 years for procuring a replacement GSU, and the lack of spare units at other facilities. The plant is projected to operating until at least 2040, thus making it crucial to have a reliable GSU ready for replacement.



Figure 2. Typical Step-Up transformer

Alternative Solutions/Alternatives Considered

1. Do Nothing – Cost: $130.9 million ($16.4M for new GSU plus $114M in energy value and potential capacity lost)

This approach involves continuing the operation without procuring a spare GSU, essentially accepting the risks associated with a potential GSU failure. When under load, a failure of the GSU transformer is a serious concern, not only because of the high financial costs but also due to safety implications. Such a failure could lead to cascading consequences where other critical equipment, such as the generator or the 345kV breaker, could be damaged or fail.

The GSU transformer is a critical component, and its failure would render the combined plant, consisting of one steam turbine and one gas turbine, inoperative. An overhaul or replacement of a GSU transformer, in the event of a failure, is expected to take a minimum of 12 months.

There is an estimated 20% risk that the generator or the 345kV breaker might be damaged during an in-service failure of a GSU. The replacement cost for the generator is estimated at $20M and for a 345kV breaker, it is around $1M. These costs are not included in the alternative cost.

The economic considerations for not having a spare GSU transformer on site, with an anticipated downtime of a full year, are significant. The breakdown for both potential capacity lost, and average energy value lost are as follows:

Capacity value potential loss impacts - $66.6M:

For this option, where the procurement and installation of the new GSU transformer are involved, a critical consideration is the multi-year financial impact, as determined by the Midcontinent Independent System Operator (MISO). MISO calculates and accredits capacity based on a rolling three-year average of historical capacity credits. Therefore, any outage that exceeds the 30-day threshold can significantly affect these calculations.

Given the expected duration of the entire process is about one full year, this threshold will be exceeded. This prolonged downtime will, therefore, trigger the multi-year financial impact, altering the capacity accreditation and potentially affecting financial projections for several years.

Average ZRC Reduction Post-Outage:

- In the event of a 365-day outage, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for each season (based on 354 ZRCs per season).
- This scenario leads to a potential annual daily loss of 118 ZRCs per season for each of these three years (354 ZRCs-236 ZRCs).

2. **Cumulative Potential Loss of Capacity Value Over Three Years:**
    - The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the 365-day outage and the additional 118 ZRCs/day applied over 90 days times four seasons over the subsequent three years.
3. **Calculation of Total Potential Loss:**
    - To estimate the potential capacity loss for this option:
        1. Calculate the Reduced Capacity Credits:
            - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
            - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).
        2. Add the Immediate Loss:
            - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (354 in this case). This gives us the immediate loss in capacity credits for that outage (31,860).
        3. Calculate the Total Revenue Loss:
            - Add the results from steps 1 and 2 to get a combined figure (63,720).
        4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)
    - This leads to a total estimated potential loss of capacity value of an estimated $16.6 million per season over the three-year period following the outage.
    - The total potential capacity value impact for a one-year outage, accounting for all four seasons, and including the impact on the subsequent three years is given by multiplying $16.6 million times four, resulting in an estimated $66.6 million potential impact.

<u>Average energy value estimated loss - $47.9M:</u>

For the scenario of a transformer failure with no spare on-site, there is a substantial potential loss in energy production due to an assumed 365-day outage. This loss can be quantified by considering the Net Energy Value (NEV) for that station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

This figure represents the potential average revenue loss for the Covert Generating Station during the outage period.

This analysis emphasizes the potential financial impact of not having a spare GSU on-site. Considering both the immediate potential loss of capacity value due to the outage, the reduced capacity credits in the subsequent three years as well as the energy value lost.

Overall advantages and disadvantages:

- **Advantages:** There is no immediate expenditure or need for storage.
- **Disadvantages:** This approach carries the highest long-term cost and risk, including the potential loss in revenue, safety hazards, and extended downtime for repairs or replacements.

2. Procure and Store a Spare GSU on-site Cost: $31.7M (including $15.3M in potential capacity value and energy value losses)

This alternative solution involves the strategic decision of procuring and maintaining a spare GSU transformer at the plant site.

- The procurement cost of the spare GSU is quoted at $12.5 million, based on an estimate from a well-known manufacturer of power transformers.
- The cost of constructing an appropriate foundation at the Covert site for the spare GSU is projected to be $200,000, as estimated by a specialized civil engineering company.
- Additional expenses related to engineering, Stand Up Transformer (SUT), and other logistical aspects are anticipated to be around $280,000.
- In the cost estimation process for large capital projects, it is a common industry practice to incorporate budget to account for unforeseen expenses that might occur during the project. The typical industry standard for such budgets can vary from 5% to 10% of the total project cost, depending on the project's complexity and risk level. For this specific project, we have included a conservative budget of 5% to the total estimated cost, considering our high predictability and control over project variables. Additionally, to cover regular operational and administrative expenses related to the project, a 20% overhead has been factored in. Consequently, the comprehensive cost estimate for this option now stands at $16.355 million (internal estimate).
- The economic considerations for procuring a spare GSU for the Covert Generating Station, with an assumed downtime of 31 days, are significant but more manageable when compared to leasing.

The breakdown for potential capacity lost, and average energy value lost are as follows:

Capacity value potential loss impacts - $11.2M:

For this option, the installation of the new GSU transformer stored on-site is anticipated to take approximately 30 days or slightly more. Specifically, if an outage exceeds 30 days, it triggers a potential multi-year financial impact due to the way MISO calculates and accredits capacity over time.

In this scenario, we will assume a worst-case scenario outage duration of 31 days within a single season. This results in the Station losing all 354 ZRCs (Zonal Resource Credits) for the season. This loss of ZRCs would result in a multiyear capacity impact, as capacity accreditation by MISO is based on a three-year average of historical capacity credits. It is important to note that if the outage had been limited to 30 days or less, or if the outage spans across parts of two separate seasons there would be no loss of ZRCs for either season, and consequently, no capacity impact.

Average ZRC Reduction Post-Outage:

- In the event of a 31-day unplanned outage during a single season, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for that season (based on 354 ZRCs per season).
- This scenario leads to a potential daily capacity loss of 118 ZRCs across an entire season (90 days) for each of these three years (354 ZRCs-236 ZRCs).

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the 31-day outage and the additional 118 ZRCs/day applied over 90 days (full season) over the subsequent three years.
- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:
        - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
        - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).

2. Add the Immediate Loss:
    - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (31 x 354 in this case). This gives us the immediate loss in capacity credits for that outage (10,974).
3. Calculate the Total Revenue Loss:
    - Add the results from steps 1 and 2 to get a combined figure (42,834).
4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)

- This leads to a total estimated potential loss of capacity value of an estimated $11.2 million over the three-year period following the outage.

<u>Average energy value estimated loss – $4.1M:</u>

For the Covert Generating Station, under the scenario of leasing a spare GSU, there is a substantial potential loss in energy production due to an assumed 31-day outage. This loss can be quantified by considering the Net Energy Value (NEV) of the station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 31-day outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($47.9M/year)/(365days/year)) x 31 days = $4.1M

This figure represents the potential average revenue loss for the Covert Generating Station during the outage period.

<u>On-site spare overall advantages and disadvantages:</u>

Advantages:

- Having a spare GSU on-site ensures rapid restoration of operations in case of a failure, thereby minimizing revenue losses.

Disadvantages:

- The approach necessitates a sizable upfront investment and requires additional storage space on-site.

3. Leasing a GSU Transformer - $36.8M in energy and potential capacity losses plus $720,000 over 20 years ($36,000/year):

This alternative explores the feasibility of entering into a lease agreement for a GSU transformer. Leasing for units of this size is a standard approach, often entailing a reservation fee of an estimated $3,000 per month. Over a span of 20 years, which is the expected life expectancy of such units, the total cost amounts to $720,000. This translates to an annual expense of an estimated $36,000. However, leasing comes with certain conditions and restrictions:

- The owner of the leased equipment can request the unit back at any point, based on their requirements.
- Availability is not guaranteed as the unit may not be on hand when needed. An industry search and examination of the transformer strategic reserve indicated that there are currently no spare units available for lease.
- Potential capacity value and energy value impacts.

Capacity value potential loss impacts - $25.0M:

For the leasing option in the GSU project, we are assuming the occurrence of an unplanned outage at the most inopportune time, specifically a scenario where a 90-day outage spans across two MISO seasons. The outage is projected to last for 31 days in one season, with the remaining duration extending into the next season. This situation results in the loss of Zonal Resource Credits (ZRC) capacity value for two separate seasons, which, due to MISO's capacity accreditation method based on a three-year historical average, effectively doubles the amount of lost capacity value over the next three years.

Average ZRC Reduction Post-Outage:

- In the event the postulated scenario, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for that season (based on 354 ZRCs per season).
- This scenario leads to a potential daily capacity loss of 118 ZRCs across an entire season (90 days) for each of these three years (354 ZRCs-236 ZRCs).
- For the unplanned 90-day outage spanning across two seasons assumed in this case, the 354 ZRCs will be multiplied times two to yield 708 ZRCs.

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the first 31-day outage in one season and then for the 59-

day outage on the following season. It also adds 118 ZRCs/day applied over 90 days (full season) over the subsequent three years.

- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:
        - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
        - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).
        - This result is multiplied times two to account for the impacts to a second season. (63,720)
    2. Add the Immediate Loss:
        - Next, multiply the number of days the plant is offline by the total ZRCs lost (354 in this case). This gives us the immediate loss in capacity credits for the 90-day outage (31,860).
    3. Calculate the Total Revenue Loss:
        - Add the results from steps 1 and 2 to get a combined figure (95,580).
    4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)
- This leads to a total potential loss of capacity value of an estimated $25.0 million over the three-year period following the outage.

<u>Average energy value estimated loss - $11.8M:</u>

For the Covert Generating Station, under the scenario of leasing a spare GSU, there is a substantial potential loss in energy production due to an assumed 90-day outage. This loss can be quantified by considering the Net Energy Value (NEV) of the station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 90-day outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($47.9M/year)/(365days/year)) x 90 days = $11.8M

Leasing option overall advantages and disadvantages:

Advantages: Leasing could offer a lower upfront cost compared to purchasing a new or spare unit outright.

Disadvantages:

- Unpredictable Availability: The availability of a leased GSU is uncertain, which can pose a significant operational risk.
- Recall Risk: There's always a possibility that the unit's owner may recall the GSU at any time, potentially causing unplanned operational downtime.
- Financial Risk: In the event of a plant shutdown due to the unavailability of a GSU, there could be a substantial financial impact.

4. Purchasing a Larger, Multi-Site GSU Transformer – Cost: $58M - $27.4M plus $30.6M in potential capacity and energy value losses:

This alternative considers purchasing a single larger spare GSU transformer that is suitable for both Zeeland Generating Station (ZGS) and Covert Generating Station (CGS). Internal economic models project the final costs to be estimated at $58M when factoring in additional expenses such as reinstallation of original overhauled GSU, modifications needed to accommodate the larger GSU at ZGS, additional outage costs and potential capacity and energy value losses. The breakdown of the internal estimate includes:

- $14M for the larger GSU transformer.
- $3M for transportation from another site and modifications needed at ZGS to accommodate bigger transformer.
- $1.25M for design and installation needs.
- $4.1M overhaul and re-installation cost of original GSU.
- $3.75M overhead estimate.
- $1.3M contingent cost to ensure compatibility with the original infrastructure. (5%)

Financial impacts:

For this option, which involves utilizing a common spare GSU for both Covert and Zeeland Generating Stations, several scenarios need to be considered to understand the financial implications fully. These scenarios vary depending on where the spare transformer is stored, and which site experiences a transformer failure. For this analysis, the worst-case scenario is assumed: the spare transformer is staged at Covert Generating Station, and a failure occurs at Zeeland Generating Station's Phase 2 transformer.

Assumptions:

For the multi-site spare option of the GSU project, the approach assumes two distinct outages, each with different implications for potential capacity value losses:

1. **First Outage - Unplanned and Single Season:**
    - The first outage, lasting 31 days, is considered unplanned and is expected to occur entirely within a single MISO season.
    - As this outage exceeds the 30-day threshold, it results in the complete loss of Zonal Resource Credits (ZRC) capacity value for that season. This loss also impacts the subsequent three years due to MISO's method of calculating capacity credits based on a three-year historical average.
    - This initial outage accounts for the period required to replace a failed GSU with the spare transformer.
2. **Second Outage - Planned and Spanning Two Seasons:**
    - The second outage, also spanning 31 days, is planned strategically to occur across the transition between two MISO seasons.
    - By dividing the outage between two seasons, each portion remains under the 30-day threshold in any single season, thereby avoiding additional ZRC capacity value penalties.
    - This outage involves reinstating the original GSU after its refurbishment, replacing the temporarily installed spare transformer.

<u>Capacity Value Potential Losses – $17.4M</u>

Average ZRC Reduction Post-Outage:

- In the event of a 31-day unplanned outage, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 366.7 ZRCs per year for that season (based on 550 ZRCs per season at Zeeland).
- This scenario leads to a potential daily capacity loss of 183.3 ZRCs across an entire season (90 days) for each of these three years (550 ZRCs-366.7 ZRCs).

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 550 ZRCs during the first 31-day unplanned outage and the additional 183.3 ZRCs/day applied over 90 days (full season) over the subsequent three years.
- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:

1. We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (366.7 in this case) and the maximum possible ZRCs of 550.
2. Multiply this difference (183.3) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (49,491).

2. Add the Immediate Loss:
   - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (550 in this case). This gives us the immediate loss in capacity credits for that outage (17,050).
3. Calculate the Total Revenue Loss:
   - Add the results from steps 1 and 2 to get a combined figure (66,541).
4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)

This leads to a total estimated potential loss of capacity value of an estimated $17.4 million over the three-year period following the first unplanned outage.

For the multi-site spare option in the GSU project, the second outage is assumed to be planned to occur between MISO seasons. This careful timing ensures that the 31-day planned outage does not fall entirely within a single MISO season, thereby avoiding any loss of Zonal Resource Credits (ZRC) and potential capacity value.

Average energy value estimated loss - $13.2M:

For the Zeeland Generating Station, under the scenario of a multi-site spare GSU, there is a substantial potential loss in energy production due to two projected 31-day outages (62 total days). This loss can be quantified by considering the Net Energy Value (NEV) and the plant's generation capacity.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $77.5M per year for the Zeeland Phase 2 Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 62-day total outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($77.5M/year)/(365days/year)) x 62 days = $13.2M

This figure represents a significant potential revenue loss for the Zeeland Generating Station during the outage period.

Overall advantages and disadvantages for the multi-site spare option:

Advantages:

- **Flexibility**: A single spare unit could cater to multiple sites, potentially offering more operational flexibility.

Disadvantages:

- **Higher Costs**: The overall cost is significantly more than the initial purchase price when factoring in the additional work required.
- **Complexity**: This option could entail more logistical and operational complexities due to the constant movement and installation work.

Recommended Alternative: #2 – Purchase a spare Covert specific GSU

Option 2 emerges as the best long-term solution for ensuring a reliable spare GSU transformer at the Covert site. It eliminates dependencies on external variables and logistics that could influence the availability of the spare GSU. Additionally, the purchased unit could seamlessly be integrated as the new GSU at the location, thereby mitigating the need for multiple installations of temporary spares.

Project Benefits and Objectives:

1. **Reduction in Downtime and Financial Losses:** Opting for a dedicated spare GSU for Covert significantly reduces unit downtime in case of GSU issues or failures. This preemptive measure results in lowered financial losses during such events.
2. **Facilitation of Proactive Engineering Design and Planning:** Having a spare GSU readily available allows for easier engineering design and forward planning. This ensures that the installation of a spare or replacement GSU can be executed efficiently ahead of any emergent needs.
3. **Mitigation of Compatibility Issues:** This option mitigates potential challenges associated with installing GSUs not specifically designed for the Covert site, system, or application. It also prevents the complexities and risks of multiple installations within a short time.
4. **Revenue Recovery through Lease Agreements:** Owning a spare GSU provides Covert with the opportunity to enter lease agreements with other utilities that may require a spare, thereby enabling cost recovery over time.
5. **Addressing Increased Risk of Failure:** The oil analysis of Covert's transformers indicated the presence of chemicals for corrosive sulfur, putting them at an increased risk of failure. Having a spare GSU acts as a failsafe, ensuring continuity in operations while mitigating actions are taken.

Conclusion: Given the considerations, Option 2 proves to be strategically sound, financially prudent, and operationally efficient. It ensures reliability, provides contingency against unforeseen GSU failures, and aligns well with long-term planning objectives, making it the most favorable choice.

Scope of Work

The aim of this project is to ensure continuous operation at the Covert site by procuring and installing a spare Generator Step-Up (GSU) transformer that can be readily deployed at any GSU location within the facility.

Scope Description:

- **Procurement of Spare GSU Transformer:**
  The project entails defining the technical specifications for a compatible GSU transformer, initiating a procurement process, and ensuring quality assurance and compliance testing for the selected unit.
- **Infrastructure Development:**
  A dedicated foundation will be designed and constructed to facilitate quick installation of the transformer at any GSU location in Covert. This includes establishing a power supply and installing necessary accessories to maintain the transformer in an operational, "ready to use" condition.

Funding and Timing

- No funding has been previously committed for this project.
- No outage is required for this project.
- Desired implementation year: 2024
- Impact if the recommended implementation year is changed: Changing the recommended implementation year could lead to potential delays in addressing and mitigating the risks associated with GSU failures at the Covert site. Consequently, this may result in extended downtimes and increased financial losses, while also potentially jeopardizing the reliability of power supply from the plant.

System Engineer

- System Engineer: Keith R. Grzegorczyk

Conceptual Estimate

Year	Loaded Cost	Description
2024	**$1,765,000**	Project engineering for Spec/RFQ/Procurement activities/Pos to secure support, Initial payment.
2025	**$25,000**	Engineering and resource needs (no payments required to SMIT)
2026	**$4,763,000**	Estimated progress payment, construction of spare GSU storage foundation, engineering, quality assurance travel.
2027	**$9,802,000**	Final payment, delivery, construction of storage foundation, closeout.

Total Cost: $16,355,000

Asset Strategy Approval Comments

The Asset Strategy Group strongly recommends approval, given the challenges currently faced at Zeeland Station and Covert Station and the extended lead times for transformers, now ranging from 2 to 4 years. Ensuring that our key capacity plants have a spare GSU on hand is of utmost importance.

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

Consumers Energy Count on Us®

Concept Approval

Covert Station Control Systems Upgrade

Date: 6/12/2024

Prepared by: Paul Ohep



Figure 1. Covert Generating Station

Executive Summary

Consumers Energy is undertaking a crucial control system upgrade at the Covert Generating Station, aimed at modernizing the existing infrastructure with advanced technological solutions. This initiative reflects our commitment to strengthening cybersecurity defenses, enhancing operational reliability, and maintaining regulatory compliance.

Project Justification and Compliance:

The upgrade follows a thorough assessment by our subject matter experts who identified significant vulnerabilities due to the use of outdated and unsupported control systems, currently operating on obsolete Windows Server platforms. These vulnerabilities expose the facility to substantial security risks, including potential cyber threats and data breaches. Following these findings, the cybersecurity leadership logged this issue as an existing risk with an assigned risk ID. This ensures continuous tracking and highlights the necessity for remediation efforts. This upgrade aligns with the CE Enterprise Patch Management Policy and fulfills the stringent requirements of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards, which emphasize regular updates and maintenance to safeguard control systems.

Financial Implications:

The total capital investment for this project is estimated at $20,042,000, including all associated loadings. This investment covers the costs of replacing hardware and software across all units at the Covert Station, transitioning to a virtualized server-based platform for all Human Machine Interfaces (HMIs) and control servers. The budget accounts for the installation of new, high-availability clustering servers, enhanced data storage solutions, and robust cybersecurity tools to protect against and manage future threats effectively.

Project Outcomes and Benefits:

Upon completion, the Covert Station will have a modernized control system architecture featuring:

- Enhanced cybersecurity measures to protect against unauthorized access and cyber-attacks.
- Increased operational reliability and efficiency using the latest hardware and software, supporting long-term operational goals.
- Compliance with current and anticipated regulatory requirements, mitigating the risk of non-compliance penalties.
- Improved system monitoring, control, and disaster recovery capabilities, ensuring continuous and secure plant operations.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$20,042,000

Proposed Start Implementation Year and Duration

2024(first year spend), 2026(installation), 2027(closeout)

Problem Description

The Covert gas generating station, operational since 2004, faces critical challenges with its outdated control systems. These challenges impact both operational efficiency and cybersecurity, necessitating an urgent upgrade to modern standards.

Current System Overview

- **Control System Composition:** Utilizes the original Mitsubishi Netmation control system for turbine operations, integrated with Emerson Ovation DCS for Balance of Plant (BOP) auxiliary equipment.
- **System Age and Efficiency:** While typical gas-fired power plants are designed with a 30-year operational lifespan, their control systems often start experiencing issues around the 10-year mark. As these systems advance in their lifecycle, the incidence of operational problems tends to increase, particularly after reaching the 15th year. At this stage, upgrading the system often becomes more economically viable than continuing with repairs.
- Due to the extensive duration of service, the original control system components at the Covert Plant are experiencing repeated failures. These issues have been analyzed by our subject matter experts, who have determined that the components have surpassed the manufacturer's recommended operational timeframe. Based on these evaluations, our experts strongly recommend an upgrade to ensure reliable and efficient plant operation.
- As a result of these issues, the turbine control systems at the site are becoming prime candidates for a comprehensive update and replacement to ensure continued efficient and reliable operation. The figure below illustrates the control system timeline since its initial installation.

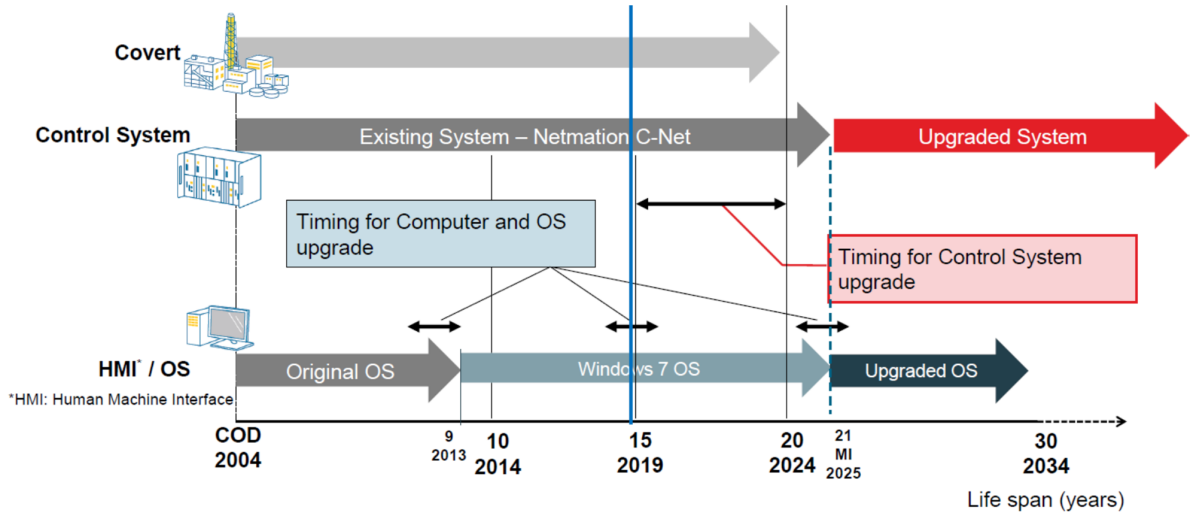


Figure 2 – Covert Netmation Control System Timeline

Operational Challenges

- **Obsolete Operating Systems:** Relies on the now-unsupported Microsoft Windows 7.
- **Outdated Control Architecture:** Utilizes the Allen-Bradley Control-Net based Netmation C-Net architecture, replaced by Mitsubishi with the newer Netmation D-Ring I/O.
- **Processor and I/O Module Obsolescence:** Process controllers and I/O modules operate on old, obsolete architecture, necessitating an upgrade.

Cybersecurity Risks

Security Project Process Risk Overview: This risk was identified and logged by the cybersecurity team prior to the acquisition of the Covert Generation plant. The existing control systems, being outdated, pose high-security risks, which have been formally recognized and assigned a risk ID for continuous tracking. Although not a formal exception, this risk is treated with the same urgency and oversight, with a clear roadmap outlined for remediation.

- **Documenting the Risk:** The risk was formally logged as an existing risk, ensuring it is tracked and managed effectively.
- **High-Risk Integration:** The outdated control systems present significant risks as they are integrated into Consumers Energy's operational framework. This has been acknowledged and tracked to ensure prompt mitigation.
- **Commitment to Remediation:** The control systems at Covert are slated for comprehensive upgrades as part of the integration and risk mitigation strategy, addressing the identified security vulnerabilities.
- **Leadership Oversight:** The Company's cybersecurity leadership has emphasized the need to fix these vulnerabilities, highlighting the importance of the planned upgrades.
- **Critical Infrastructure Protection:**
    - The plant's control systems are integral to the nation's Critical Infrastructure and are subject to NERC Critical Infrastructure Protection (CIP) requirements.
    - Due to the outdated software, the plant is vulnerable to cybersecurity threats. This includes potential exploitation by bad actors and nation states due to unpatched software vulnerabilities.
- **Challenges in System Maintenance:**
    - The plant's reliance on outdated platforms, such as Microsoft Windows 7, and specific applications like the Mitsubishi Netmation, has reached a critical juncture where manufacturer support has ceased.
    - Extended support from Microsoft ended in January 2020. This lack of support inhibits the ability to apply necessary patches and maintain these systems, rendering them susceptible to vulnerabilities. Without these updates, the software may become a target for malicious actors and nation-states, posing a significant risk to our critical infrastructure.

- **Compliance with Corporate Cybersecurity Standards:**
    - The current systems at Covert do not meet the Windows Server Hardening Standard required by Consumers Energy. Servers are required to be on newer builds (Windows Server Enterprise 2016 and 2019).
    - Aging infrastructure limits the effectiveness of crucial cybersecurity measures. Specifically, tools designed for enhancing control network security, such as the Mitsubishi Netmation Protect Pack (NPP), are incompatible with the outdated hardware and software, restricting our capability to perform essential patching and antivirus protections.
- **Limitations on Malware Protection:**
    - The antiquated operating systems currently in use offer limited support for up-to-date malware protection solutions. This limitation not only increases the risk of infection from new strains of malware but also complicates efforts to maintain a secure operational environment, essential for the uninterrupted generation of energy**.**

Alternative Solutions/Alternatives Considered

1. Do Nothing

Continued Use of Outdated Systems:

- **Obsolete Control Systems:** Persisting with the existing Mitsubishi NetMation control systems, which are beyond their operational life cycle and no longer supported by necessary updates or patches.
- **Operational Inefficiency:** These systems are prone to inefficiencies and reliability challenges, impacting overall plant performance and safety.

Policy Violation and Security Implications:

- **Violation of CE Patch Management Policy:** This option results in a direct violation of the CE Enterprise Patch Management Policy, indicating a failure to meet corporate standards for maintaining system security and integrity.
- **NERC CIP Non-compliance:** Retaining outdated systems does not comply with NERC Critical Infrastructure Protection (CIP) requirements, potentially leading to fines up to $1.2 million per day. This represents a significant financial risk and regulatory exposure.
- **Lack of Updates and Patches:** Inability to adhere to regular system patching and update protocols, which are essential for maintaining operational security and efficiency.

Cybersecurity Risks:

- **Heightened Vulnerability:** Using outdated and unpatched systems significantly increases vulnerability to cyber threats. This exposes the plant to potential security breaches that could compromise the integrity of plant operations and sensitive data.
- **Potential for Severe Breaches:** The risk of a cybersecurity event could lead to substantial damage to critical equipment. Repair and replacement in such scenarios would require considerable time and resources, exacerbating operational disruptions and financial burdens.

Operational Impact:

- **System Failures and Trips:** Failures in communication modules linked to remote I/O cabinets could trigger site-wide unit trips, leading to substantial generation and capacity losses, varying by season.
- **Disruption in Control and Monitoring:** Potential disruptions in maintaining consistent operational control and effective system monitoring could deteriorate the plant's overall functionality and response capabilities.

Long-term Consequences of Inaction:

- **Inevitable Need for Future Upgrades:** Doing nothing only postpones necessary upgrades, which will eventually need to be performed under less favorable circumstances and likely at higher costs.

- **Risk of Component Failure:** The aging systems might fail unpredictably, potentially leading to derates or extended downtimes. Control system failures could also precipitate further mechanical component or system failures.
- **Unpredictable Outages and Damage:** It is very challenging to predict when these failures might occur and the extent of potential damage.

Conclusion: Choosing the "Do Nothing" option presents significant cybersecurity risks and operational inefficiencies that could jeopardize the safety, reliability, and regulatory compliance of the Covert Generating Station. This option fails to mitigate any of the identified risks and only delays the inevitable, necessary upgrades, increasing the potential costs and impacts of future failures. This approach is strongly inadvisable as it exposes the facility to increased risks and potential catastrophic failures, which could have severe repercussions for both the plant's operations and the company's reputation.

Option 2: Replace Covert Station Hardware (including I/O modules) and Software to latest architecture - $20,042,000 (internal loaded estimate includes Netmation Care Parts Program)

Under Option 2, we propose an extensive upgrade of the Covert Mitsubishi Turbine Control System to the latest version of Netmation, which includes the replacement of hardware, I/O modules, servers, workstations, network switches, and software to the latest architecture. A significant enhancement to this option is the planned acquisition of the optional Netmation Care Parts Program for an additional investment of $1.5M. This program is specifically designed to support Mitsubishi Power Americas' customers with an efficient, cost-effective solution for managing spare parts over the control system's lifecycle.

Key Benefits of Upgrading to the Latest Netmation System:

- Enhanced System Security and Reliability:
    - Guarantees a secure and reliable control system, foundational for uninterrupted and safe plant operations.
- Compliance with CE Enterprise Standards:
    - Enables adherence to the CE Enterprise Patch Management Policy, requiring regular system updates for maintaining operational security.
    - Ensures timely application of security patches released by Original Equipment Manufacturers (OEM), alongside continuous antivirus and malware protection, crucial for safeguarding system integrity against vulnerabilities and ensuring compliance with enterprise cybersecurity standards.
    - Upgrades to the latest versions of control software and operating systems (including Microsoft, Proxmox, and Linux), accessing up-to-date technological enhancements.
- D-Ring I/O System Advantages:
    - Implements redundant I/O adapters, enhancing system resilience against hardware failures.
    - Introduces network broken point detection, improved diagnostics, easier log collection, and consolidated module functionality, reducing the number of spare parts required.
- Remote Combustion Tuning:
    - Enables remote adjustments to the combustion system, accommodating seasonal turbine performance optimizations.

- Cybersecurity Lifecycle Management Program with Netmation Protect Pack integration:

  The upgraded control system at the Covert plant, including the introduction of the Netmation Protect Pack (NPP), significantly enhances cybersecurity management across several domains:

  - **Regular System Patching and Updates**: NPP ensures that the latest security patches and system updates are applied, aligning with CE Enterprise Patch Management Policy for maintaining operational security. This routine patching is crucial, especially for systems under constant evolution in cybersecurity threats.
  - **Advanced Threat Management**: NPP integrates comprehensive cybersecurity solutions including threat and risk management, which are vital for protecting the control systems against unauthorized access, malware, and ransomware attacks.
  - **Application Control and System Health Monitoring**: With NPP, the plant can manage applications more securely and monitor system health effectively, ensuring that any potential security risks are identified and mitigated promptly.
  - **Compliance with Regulatory Standards**: The NPP platform supports compliance with NERC/FERC CIP reliability standards, crucial for plants part of the nation's critical infrastructure. This compliance is enforced through regular reports and audits, ensuring that the plant meets all necessary cybersecurity benchmarks.
  - **Backup and Recovery Protocols**: The program includes robust backup and recovery systems, which are essential for restoring operations quickly and securely in the event of a cyber incident.
  - **Vulnerability Scanning and Assessment**: Regular scans are conducted to identify and address vulnerabilities, with assessments ensuring that the control systems are fortified against potential breaches.
  - **Periodic Site Reviews and Assessments**: Alongside the continuous monitoring and updates, periodic site visits are conducted to review the system's security posture and implement necessary improvements based on the latest cybersecurity trends and findings.

Benefits of Including the Netmation Care Parts Program:

While the core of Option 2 focuses on modernizing the Covert station's control systems, the Netmation Care Parts Program offers additional, valuable benefits:

- Strategic Parts Management: The program provides a comprehensive solution for managing spare parts throughout the system's lifespan, ensuring that critical spares are readily available on-site and non-critical spares are secured at a Mitsubishi warehouse, thus minimizing potential downtime.
- Alignment with LTSA and Plant EOL: By securing spare parts for the Netmation D-Ring Control Systems for all three blocks, the program supports the units up to the expected end of the Long-Term Service Agreement (LTSA) in 2038, offering a strategic alignment with future operational needs.

- Reduction in Variable Costs: This strategic financial approach not only aligns with the plant's LTSA but also serves as an effective method to support the units while substantially reducing costs. By transitioning spare parts expenses from variable, often unforeseen costs to a planned approach, the program provides a more predictable and manageable cost structure.

Option 3: Limited Upgrade Excluding C-Net I/O Transition – $5M initial cost with a minimum cost of $20,042,000 within 5 years for inevitable full upgrade.

Option 3 proposes a targeted upgrade path for the Covert Mitsubishi Turbine Control System, focusing on updating servers, workstations, network switches, and the control system software. This approach notably omits the upgrade of the existing C-Net I/O modules to the newer D-Ring I/O architecture, aiming to streamline the upgrade process by minimizing hardware alterations and the associated labor costs.

Key Aspects of Option 3:

- Selective Modernization Efforts:
    - Concentrates on upgrading the control system's computational and networking backbone, including servers and switches, alongside software enhancements.
    - Retains the current C-Net I/O modules, bypassing the shift towards the more modern D-Ring I/O system architecture.

Considerations and Limitations:

While this strategy might appear to offer a straightforward path to modernization with potentially lower initial costs, it's essential to acknowledge the broader implications and the benefits that will be missed:

- Foregoing Enhanced Reliability and Diagnostics:
    - By not adopting the D-Ring I/O system, the plant misses out on significant reliability improvements, including redundant I/O adapters and advanced diagnostics, that could mitigate the risk of system failures and facilitate faster troubleshooting.
    - The architecture is significantly past the recommended replacement interval. Commissioned in 2004, all (3) systems will be 22-years old in 2026, which is 7-years beyond the 15-year replacement recommendation. The reliability of the system will be in question and replacement parts become completely obsolete as the system ages further.
- Continued Vulnerability to Network Failures:
    - The absence of network broken point detection capabilities means that the system remains more susceptible to network issues, potentially affecting operational stability and increasing downtime.
    - The controllers that operate the plant equipment would still be vulnerable to cyber-attacks.
    - Vulnerabilities and reliability of the old controllers would be decreasing as they age.

- Unrealized Operational Efficiencies:
    - The consolidated module functionality and reduced spare parts requirements offered by the D-Ring architecture represent unclaimed efficiencies that could streamline maintenance operations and reduce long-term costs.
    - This option does not replace any of the thousands of I/O modules that are obsolete with the old C-Net architecture.
    - The following benefits of the D-Ring I/O would not be realized: redundant I/O adapters for failure-resistant I/O network, network broken point detection, consolidated module functionality for a reduction of required spares, Improved I/O modules diagnostics and easier log collection.
- Stagnation in Technological Advancement:
    - Electing to bypass the D-Ring I/O upgrade will limit the system's future scalability and adaptability to emerging technologies.

Option 3 offers a constrained upgrade focusing on immediate needs while leaving existing I/O infrastructure untouched. This choice might initially seem prudent from a cost perspective; however, the initial cost of $5M would only provide a short-term solution that would eventually still require the full I/O and controller replacement as recommended. As the inevitable upgrade is delayed, the generating plant gets nearer its end of life and less time remains to maximize the benefit of the investment.

Recommended Alternative: # 2. Replace Covert Station Hardware (including I/O modules) and Software to latest architecture - $20,042,000 (internal estimate includes Netmation Care Parts Program).

The decision to pursue Option 2, the comprehensive replacement of all hardware and software to the latest architecture at the Covert Generating Station, is underpinned by detailed asset reviews, cybersecurity assessments, and recommendations from Mitsubishi. This option promises enhanced reliability, security, and economic benefits, crucial for meeting future operational and security demands.

Key Findings and Assessments:

- **Asset Review Findings:**
    - Aging Infrastructure: PCs running Windows 7 are over 12 years old, facing imminent drive failures. Control processors and I/O modules are over 20 years old, significantly beyond their effective operational lifespan.
- **Cybersecurity Assessment Results:**
    - Security Vulnerabilities: Current system monitoring and access control are limited to non-existent, leaving critical infrastructure highly vulnerable to unauthorized access and malicious activity.
    - Corporate Mandate: The cybersecurity leadership has logged the issue as an existing risk with an assigned risk ID, highlighting the urgent need for system upgrades to mitigate potential security risks. This tracking mechanism ensures continuous oversight and emphasizes the necessity for immediate remediation efforts to address the identified vulnerabilities.
- **Manufacturer's Recommendation:**
    - Mitsubishi's Urgency: Mitsubishi has recommended that a component and architecture replacement should have occurred by 2019 to ensure system integrity and security up to its expected end of life.
- **Economic and Operational Efficiency:**
    - Long-Term Cost Savings: Although initially more capital-intensive, this option prevents the frequent and costly updates required if older systems were maintained. By investing in a comprehensive overhaul now, the station avoids the escalated costs associated with piecemeal upgrades or emergency repairs in the future.
    - Improved System Longevity and Reliability: The upgrade extends the operational lifespan of the control systems, ensuring they remain functional and effective until at least 2038, as per Mitsubishi's guidelines. This not only enhances operational reliability but also provides a clear, long-term upgrade path through virtualized systems.

Scope of work

Control System Requirements:

1. **Independent Control Systems:**
    - Each generating unit (Block) will be equipped with independent control systems featuring secure network interfaces to ensure isolated operations and enhanced security.
2. **Virtualization and Server Infrastructure:**
    - Implementation of a virtualized Netmation server-based platform for all Human Machine Interfaces (HMIs) and Netmation servers.
    - Utilization of Proxmox Virtual Environment on multiple host rack servers to provide high-availability clustering.
    - Network Attached Storage (NAS) will be used for robust data storage and integrity.
3. **Networking and Power Supply:**
    - Installation of redundant 1Gbps and 10Gbps managed switches and firewalls to ensure network resilience and security.
    - Uninterruptible Power Supplies (UPS) will be installed for all server rack components and PCs to provide continuous power and prevent data loss during power disruptions.
4. **Cybersecurity Enhancements:**
    - Deployment of the Netmation Protect Pack (NPP) to offer integrated threat management, risk management, and application control.
    - Comprehensive cybersecurity tools will be implemented, including disaster recovery, logging, Active Directory authentication, and regular system patching and updates to comply with NERC CIP and Consumers Energy standards.
5. **System Software and Hardware Upgrades:**
    - The project will include the latest approved operating systems for virtualized servers and HMIs, along with application software and components.
    - Monthly software patching and threat monitoring as part of Mitsubishi's Cybersecurity Lifecycle Management Program.
    - Upgrade of the Netmation D-Ring (I/O) System, including the replacement of C-Net I/O hardware modules with the latest D-Ring modules and processors on all Gas Turbine Control (GTC) and Steam Turbine Control (STC) systems.

6. **Remote Management and Tuning:**
    - Implementation of remote tuning capabilities for combustion tuning, compliant with NERC CIP, through a secure and controlled connection, facilitating quicker and cost-effective tuning.
7. **Spare Parts Management:**
    - Establishment of the Netmation Care Parts Program to ensure availability of critical spare parts for the Netmation D-Ring Control System on-site and non-critical spares stored at a Mitsubishi warehouse, supporting all units until the end of the current LTSA in 2038.

Funding and Timing

- A planned outage is required for this project.
- Desired implementation year:
    - First year spend: 2024
    - Implementation year: 2026

System Engineer

- System Engineer: Kevin A. Ortner

Conceptual Estimate

Year	Loaded Cost	Description
2024	$3,776,000	Engineering and initial contract award to Mitsubishi
2025	$4,922,000	Engineering
2026	$10,304,000	Spring and fall Outage installations of all Servers and I/O and controllers
2027	$1,040,000	Acceptance and closeout

Total Cost: $ 20,042,000

Asset Strategy Approval Comments

Asset Strategy approves this project due to its critical alignment with essential cybersecurity requirements and the imperative to sustain operational reliability at the Covert Station. This strategic upgrade not only ensures compliance with the CE Enterprise Patch Management Policy but also integrates the latest technological advancements, thereby fortifying the long-term integrity and efficiency of the plant's operations.

This project at the Covert Generating Station **is** recognized in the 2023 electric rate case, not as a standalone item but within the broader category of non-LTSA (Long Term Service Agreement) projects. This categorization reflects the strategic allocation of funds for various essential undertakings at Covert, following its recent acquisition.

The allocated budget under work item 1218, titled "Covert -Non LTSA Capital - Extras not included in contract," encompasses this and other similar projects. The figures covered under this line item are as follows:

Amount set for Bridge year: $ 3,943,000

Amount set for test period: $ 5,510,000

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

Consumers Energy Count on Us®

Concept Approval

Covert station DCS Evergreen Upgrade

Date: 3/2/2024

Prepared by: Paul Ohep



Figure 1. Covert Generating station

Executive Summary

The Covert gas generation plant, operational since 2004, faces significant challenges with its Emerson Ovation Distributed Control System (DCS). The system's obsolescence, cybersecurity risks, and operational inefficiencies necessitate an urgent upgrade to the latest version to enhance reliability, security, and compliance with regulatory standards.

Problem Overview:

1. **System Obsolescence and Lack of Support:** The existing DCS (version 3.5.1) is outdated, with Emerson and Microsoft no longer providing support. The software and operating systems, including Windows 7 and Server 2008R2, have reached end-of-life, with no extended support available.
2. **Cybersecurity Risks and Compliance Challenges:** The plant's control systems are subject to NERC Critical Infrastructure Protection (CIP) requirements. Continued use of outdated software exposes the plant to heightened cybersecurity threats and potential fines up to $1.2 million per day for non-compliance.
3. **Operational Risks and Inefficiencies:** Failures in communication modules to remote I/O cabinets have led to generating unit trips, causing significant generation and capacity losses. The main controller drop is overburdened, increasing the risk of simultaneous unit trips, necessitating a system restructuring.

Alternatives Considered:

1. **Do Nothing:** Persisting with the current system risks violating CE Enterprise Patch Management Policy, failing to meet corporate standards, and incurring substantial fines for non-compliance with NERC CIP requirements.
2. **Replace DCS with Latest Version:** A proactive upgrade at an estimated cost of $3,540,000 enhances system security, ensures compliance with CE Enterprise standards, and accesses the latest technological innovations for improved operation.

Recommended Solution: Upgrading the DCS to the latest version is the chosen approach, driven by the need for enhanced security, compliance with enterprise standards, and technological advancement. The upgrade includes:

The upgrade of Covert Station's DCS to the latest version represents a critical step towards maintaining the plant's operational integrity, adhering to cybersecurity standards, and ensuring regulatory compliance. This initiative is not only a response to current challenges but also a proactive measure to future-proof the plant's control systems.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$3,540,000

Proposed Start Implementation Year and Duration

2024-2026

Problem Description

The Covert gas generation plant, in operation since 2004, is currently facing significant challenges with its control system, the Emerson Ovation Distributed Control System (DCS). This system, essential for the plant's operation, is now outdated and poses several risks and inefficiencies.

1. **System Obsolescence and Lack of Support:**
    - The plant's Emerson Ovation DCS, at version 3.5.1, is outdated with Emerson and Microsoft is no longer providing support.
    - Critical software, including Emerson Ovation version 3.5 and the Windows operating systems (Windows 7 and Windows Server 2008R2), have reached their end-of-life, with extended support from Microsoft having ended in January 2020.
2. **Cybersecurity Risks and Compliance Challenges:**
    - The plant’s control systems are integral to the nation’s Critical Infrastructure and are subject to NERC Critical Infrastructure Protection (CIP) requirements.
    - Due to the outdated software, the plant is vulnerable to cybersecurity threats. This includes potential exploitation by bad actors and nation states due to unpatched software vulnerabilities.
    - The cybersecurity tools currently in use, such as the Power & Water Cybersecurity Suite (PWCS), are nearing the end of their support and are incompatible with newer versions of the Ovation system.
3. **Balance of Plant (BOP) Control Inefficiencies:**
    - There have been incidents of failures in communication modules to remote I/O cabinets, leading to generating units going offline.
    - The power supplies in the Ovation cabinets, having exceeded their manufacturer suggested lifespan, need urgent replacement.
4. **Operational Risks and Inefficiencies:**
    - The main controller drop, responsible for equipment control across all three generating units, is overburdened and has been subjected to additional equipment and data link controls over the years.
    - This overextension has led to increased risk of simultaneous unit trips and necessitates a restructuring of the control system to ensure operational efficiency and safety.
    - The current system configuration requires site-wide outages for certain upgrades, leading to significant operational risks and inefficiencies.

The Covert Station's control system is in urgent need of an upgrade. The current Emerson Ovation DCS system, being outdated, poses significant risks in terms of cybersecurity, operational efficiency, and compliance with regulatory standards. An upgrade to the latest

Emerson DCS Evergreen system is crucial to address these challenges, enhance the plant's operational reliability, and ensure compliance with critical infrastructure protection standards.

Alternative Solutions/Alternatives Considered

1. Do Nothing

   Choosing not to upgrade the Distributed Control System (DCS) at Covert Station involves persisting with the current, outdated systems. This approach, however, leads to several critical issues:

   - **Continued Use of Outdated Systems:**
     - Retaining the existing retired DCS operating systems, which are beyond their optimal life cycle and no longer receive necessary updates or patches.
   - **Policy Violation and Security Implications:**
     - This course of action results in a direct violation of the CE Enterprise Patch Management Policy, failing to meet established corporate standards for system maintenance.
     - Non-compliance of NERC Critical Infrastructure Protection (CIP) requirements can lead to fines of up to $1.2 million per day.
     - Inability to adhere to regular system patching and update protocols, essential for operational security and efficiency.
   - **Cybersecurity Risks:**
     - Significantly heightened vulnerability to cyber threats due to the use of outdated and unpatched systems.
     - Increased risk of security breaches, which can compromise the integrity of plant operations and sensitive data.
   - **Operational Impact:**
     - Likely occurrence of system inefficiencies and reliability challenges.
     - Failures in communication modules linked to remote I/O cabinets can trigger site-wide unit trips, leading to considerable generation and capacity losses. The extent of these losses varies depending on the time of year.
     - Potential disruption in maintaining consistent operational control and effective system monitoring.

2. Replace Covert Station Ovation DCS with the latest version available at the time of the project - $3,540,000 (internal estimate)

Upgrading the Distributed Control System (DCS) at Covert Station to the latest version represents a proactive approach to maintaining system security and operational efficiency. Key aspects of this option include:

- **Enhanced Patching and Security:**
  - Capability to continually patch computer operating systems, ensuring the DCS remains secure and reliable.
  - Alignment with the CE Enterprise Patch Management Policy for regular system updates.

- **Up-to-Date Control Software and Operating Systems:**
  - Introduction of the latest versions of Emerson Ovation control software, Microsoft, and VMware operating systems.
  - Ensures reliable operation and control of the generating units with the most current software versions.
- **Access to Latest Features and Enhancements:**
  - Eliminate Single Point Vulnerability to cause multi-unit trips by partitioning of I/O to other drops.
  - Availability of the latest feature enhancements for improved operation of the unit.
  - Ability to apply the most recent patches provided by cybersecurity PWCS applications.
- **Compliance with Enterprise Standards:**
  - Meeting the requirements of the CE Enterprise Patch Management Policy for annual patching of operating systems.
  - Running antivirus and malware prevention software on all systems as a standard security protocol.
  - Prompt application of new security patches released by OEMs for software applications.

Recommended Alternative: # 2. Replace Covert Ovation DCS with the latest version available at the time of the project - $3,540,000.

The decision to upgrade Covert Station Distributed Control System (DCS) to the latest version, at an internal estimated cost of $3,540,000, is driven by several compelling reasons:

- **Enhanced System Security and Reliability:** The upgrade ensures that the DCS remains patchable, aligning with evolving cybersecurity measures. This is vital for maintaining a secure and reliable control system in the face of increasing cyber threats.
- **Compliance with CE Enterprise Standards:** Regular patching and updating of the system as per the CE Enterprise Patch Management Policy are mandatory for operational security. This upgrade facilitates annual patching of operating systems, along with consistent running of antivirus and malware prevention software.
- **Ensuring Compliance and Avoiding Financial Risks:** Adherence to NERC Critical Infrastructure Protection (CIP) standards is crucial, as the plant's control systems are integral to the nation's Critical Infrastructure. Non-compliance risks not only operational integrity but also incurs substantial fines, potentially up to $1.2 million per day.
- **Technological Advancement:** By upgrading to the latest Emerson Ovation control software and operating systems (Microsoft and VMware), the units gain access to the latest technological innovations. This ensures efficient and reliable operation and control of the generating units.
- **Feature Enhancements and OEM Support:** The upgrade enables the incorporation of the latest feature enhancements, improving operational capabilities. It also ensures that the station can apply the latest security patches released by Original Equipment Manufacturers (OEMs), maintaining the system's integrity.

Option 2 aligns with the necessary cybersecurity and operational standards. This upgrade is a strategic investment in the plant's future, ensuring its compliance, security, and operational excellence.

Scope of work

1. **Software and Operating System Upgrades:**
    - Upgrade all Ovation software to the latest version.
    - Update all Operating Systems to the latest version supported by Ovation.
2. **Hardware and Infrastructure Replacement:**
    - Install the latest generation of Ovation power supplies.
    - Replace all network switches, routers, firewalls, and media converters.
    - Upgrade fiber optic cabling to support the new system and Remote Node Interface.
    - Replace all Remote Node Controllers (RNC and MAU) with Remote Node Interface (RNI) architecture for remote I/O cabinets.
3. **Control System Restructuring:**
    - Add two new controller drops to redistribute the logic and control from the existing drop1 controller.
4. **Cybersecurity Enhancements:**
    - Upgrade PWCS cybersecurity tools, incorporating new hardware and software solutions.
5. **Virtualization and Server Upgrades:**
    - Transition to an Ovation Virtualized system, including VMware hosts, Storage Area Network (SAN), network switches, Thin Clients, Network-Attached Storage (NAS), and all necessary components and software.
6. **Communication System Upgrades:**
    - Replace Mitsubishi gateway devices and software for data link communication with the latest secure protocols.

Funding and Timing

- A planned outage is required for this project.
- Desired implementation year: 2024

System Engineer

- System Engineer: Kevin A. Ortner

Conceptual Estimate

Year	Loaded Cost	Description
2024	$551,500	Contract award, engineering, and project management support.
2025	$2,988,500	Emerson DCS Evergreen replacement of existing application software and operating systems and equipment.

Total Cost: $ 3,540,000

Asset Strategy Approval Comments

Asset Strategy approves this project because of its alignment with the essential cybersecurity requirements and the need to maintain operational reliability at the Covert Station. This strategic upgrade ensures compliance with the CE Enterprise Patch Management Policy and leverages the latest technological advancements, thus safeguarding the long-term integrity and efficiency of the plant's operations.

This project at the Covert Generating Station **is** recognized in the 2023 electric rate case, not as a standalone item but within the broader category of non-LTSA (Long Term Service Agreement) projects. This categorization reflects the strategic allocation of funds for various essential undertakings at Covert, following its recent acquisition.

The allocated budget under work item 1218, titled “Covert -Non LTSA Capital - Extras not included in contract,” encompasses this and other similar projects. The figures covered under this line item are as follows:

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Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

EXHIBIT A-203 (MEW-10)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002894	**2026**	**2**	**Literal**

Investment Name	Scenario
CGS - Units 1,2,3 NERC Relay Replacements and Test Switch Installation	**Draft**

Value Function	**Consumers Energy Value Function**

Each unit has multiple digital protection relays to ensure protection to the generation equipment (Generators/Exciters/Transformers) from local faults as well as to ensure protection from grid disturbances that could damage our valuable equipment. The relays within the scope of this project have manufacture/installation dates very close to 2002. At Covert – there are two specific brands of relays in scope for this work – Beckwith and Schweitzer relays. In addition to changing the relays from 2002 vintage to today's models, this project will install relay test and cutout switches to be consistent with industry best practices and to ensure safe and reliable testing and maintenance. The original relays at Covert were not installed with the necessary test and cutout switches - which requires that the unit be offline for maintenance and replacement and creates a greater potential for human performance errors that can lead to forced shutdowns.

Investment Type	Generation	Planning Portfolio	Covert
Facility	Covert / Covert		
Executive Summary	This project proposes the replacement of aging digital protection relays and installation of relay test and cutout switches across Units 1, 2, and 3 at Covert Generating Station. These relays are critical for protecting generation equipment (generators, exciters, transformers) from local faults and grid disturbances. The existing relays, installed around 2002, are approaching or have reached the end of their recommended 25-year service life, and failures have already begun to occur. Objectives Avoid human performance errors leading to forced outages and reduce the need for offline maintenance. Scope & Schedule Unit 3: Spring 2026 major outage. Unit 1: Fall 2026 major outage; most complex and critical. Unit 2: Split between Spring and Fall outages in 2027 due to limited outage duration. Justification & Risk Assessment Service Life: Relays will be at 24–25 years of service at time of replacement, aligning with System Protection recommendations. Observed Failures: Unit 3 experienced a relay failure in December 2024; currently operating without redundant protection in one zone. Forced Outage Risk: If backup relay fails before scheduled outage, a 14-day forced outage would be required. Assumed probability of this risk: 5%. Estimated capacity revenue losses: $1,374,765 (based on MISO rules and 75% of CONE value). Industry Standards: Running relays to failure is not acceptable practice and exposes the company to scrutiny and reliability risks. Test Switches: Without switches: increased risk of human error during maintenance. With switches: risk probability reduced from 5% to 1%. Avoids need to unwire/rewire relays during maintenance. Estimated annual O&M cost avoidance: $5,000. Recommended Alternative: Replace all NERC protection relays and install test/cutout switches to ensure safe, efficient, and reliable operation. Other Alternative (Not Chosen): Replace relays only, without installing test switches. Estimated cost savings: $150,000 per unit. Not recommended due to increased maintenance complexity and risk exposure.		
Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Unit - Plant
	Scope	•Unit 3 will be done in Spring 2026 Major Outage; Unit must be out of service for this work to be performed. It is best to do these jobs (especially the first ones) in MAJOR outage windows because of the complexity of this project. •Unit 1 will be done in Fall 2026 Major Outage; for same reasons as Unit 3. Unit 1 will be the most complex and is the most crucial to being funded in 2026. •Unit 2 will be done in two parts – spring and fall outages of 2027 because there is not a long enough outage for all of the work, we will split into two parts. •It is important that these projects be scheduled soon because the relays are at end of life and at least one on Unit 3 has showed indications of failing. General Scope: For each of Covert's Generating Units, replace all relays (primary & backup) associated with Gas Turbine Generator & Excitation Protection, Steam Turbine Generator & Excitation Protection, Generator Step-up Transformer Protection, Station Auxiliary Transformer Protection, & GTG & STG Transformer Winding Protection Relays (single relay for each). With each of the relay replacements, provide relay cutout switches, sufficient test switches, and a sufficient time signal to synchronize all relay time-stamps to a new GPS timeclock. This project will procure all relays and time clocks for each unit as well as all relevant hardware and cabinetry (or new panels as required) to create the space required to install the new gear (original equipment does not have workable relay cutout switches and test switches or sufficient space within or on the existing panels/cabinets to simply do a "remove/replace" project).
	Objectives	This project is needed to preclude unnecessary risk associated with possible relay failures as our relays are at end of life. Running to failure is not an option for relay protection equipment because of the extremely high costs of equipment failures that could result if relay protection schemes failed to operate as designed. In late 2024, Covert experienced its first indication of a relay failure on unit 3, and is operating at this time with no redundant protection in this specific zone. The failed relay is original from 2002 and more relay failures can be expected as time goes on. With this as an example – if Covert were to have a failure of the remaining protection scheme in this zone – a forced outage would be required to prevent an event – and it is expected that the turn-around time for sourcing, testing, installation, and commissioning of relays like this would take ~ 2 weeks if all went well. Relay manufacturers and Consumers Energy's High Voltage Distribution group use 25 years as recommended service life for these types of devices. Project Benefits All of the NERC protection relays will be replaced in accordance with industry best practices and relay test & cutout switches will be installed to make testing and maintenance safer and more consistent to ensure reliable relay and unit performance. If a relay failure were to occur in the future, relay replacement could be done online if deemed necessary.

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002894	**2026**	**2**	**Literal**

Investment Name	Scenario
CGS - Units 1,2,3 NERC Relay Replacements and Test Switch Installation	**Draft**

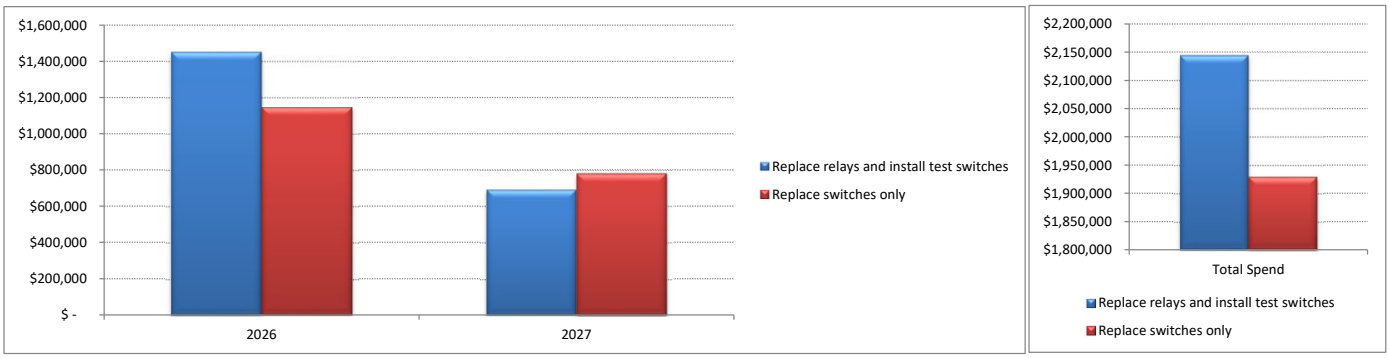
Value Function	**Consumers Energy Value Function**

	Planner Recommended Alternative	Replace NERC relays and install test switches. -Beckwith OEM for many of the relays in scope recommends replacement at 1.5x the relay warranty period (or 15 years). Beckwith acknowledges that they have many relays in service at 20 years. Within Consumers Energy's HVD relay replacement program – relays are replaced at 25 years – which is where we are establishing the need for this action. -Schweitzer Engineering Laboratories (SEL) is the OEM for the balance of the relays in service at Covert – expects their relays to have a minimum service life of 20 years. Within Consumers Energy's HVD relay replacement program – relays are replaced at 25 years. Other alternative (not chosen) For each of three units, replace only the relays and do not install test/cutout switches contrary to industry best practices – cost savings of ~$150K/unit estimated. This option is not recommended because to perform relay maintenance at Covert requires the relays to be unwired and rewired – each time maintenance is performed and this is not a good way of doing maintenance and is not in keeping with industry best practices.
	Assumptions	System Protection recommends relay replacements at 25 years of service. These relays were first put in service ~ 2002. The project schedule proposed would have Units 3 & 1 at 24 years of service and Unit 2 at 25 years of service at replacement. We are starting to observe relay failures (Unit 3). Loss of protection would require an unacceptable outage and loss of generation that would easily exceed this project cost in energy value replacement costs. (Example: if Unit 3 experienced failure of the redundant protection device, it is estimated that an outage of ~ 14 days would be required to procure, test, install, & commission – new relays to restart the unit.) . Running these relays / components to failure is not industry standard. Risks associated with running protective relays to failure – compromising either protection or experiencing an uncoordinated protective function or unit trip from a faulty relay is simply not industry best practice and would call unacceptable scrutiny upon CE and our practices. These relays are being replaced at the best time with respect to length of service and exposure to unnecessary failures. Unit 3's Backup Excitation Protection Relay failed in service in December of 2024 after this project was in conceptual form. These devices do not fail frequently prior to end of life. Assume that there is a single relay that has failed (as in the case of Unit3) – and it's backup relay fails before we have an outage of opportunity to repair or replace the first failed relay – a forced outage is required. (This assumes that the relays fail passively and do not initiate a unit trip.) Assume a 5% chance of realizing this risk will be assumed based on equipment redundancy. Risk (HIGH) - relatively low probability * HIGH consequences if we continued to run with no protection and had an event that relays did not protect for because we did not come offline to fix. Potential capacity losses from a 14 day forced outage have been calculated using a calculator provided by capacity forecast group to be $1,374,765. This includes a three year impact in accordance with MISO rules. Assume a CONE value of $130,930. a 75% of CONE value figure was used for calculations as is customary. Option without test switches does not fully mitigate lost generation risk as it creates opportunities for human performance errors during maintenance. Installation of these switches has become an industry standard and a standard companywide as well. Assume that probability was reduced from 5% to 1%. By installing test switches, maintenance is avoided since there would be no need to unwire and rewire the relays every time maintenance is performed. Assume annual O&M cost avoidance of $5k.
Alternative Details	Replace relays and install test switches	Replace relays and install test switches
	Replace switches only	Replace switches only.

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
Replace relays and install test switches	Recommended	$ 2,143,637	1/1/2026
Replace switches only	Candidate	$ 1,929,174	1/1/2026

Name	Status	2026	2027
Replace relays and install test switches	Recommended	$ 1,451,582	$ 692,055
Replace switches only	Candidate	$ 1,147,794	$ 781,379



Forecasts - Draft (Replace relays and install test switches)

Account Type	2026	2027

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002894	**2026**	**2**	**Literal**

Investment Name	Scenario
CGS - Units 1,2,3 NERC Relay Replacements and Test Switch Installation	**Draft**

	Value Function	**Consumers Energy Value Function**
Capital	$ 1,306,424	$ 622,850
Cost Of Removal	$ 145,158	$ 69,206
O&M	$ -	$ -

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN003012	**2025**	**5**	**Literal**

Investment Name	Scenario
CGS - U13 Circ Water pump replacements	**Draft**

Value Function	**Consumers Energy Value Function**

Investment Type	Generation	Planning Portfolio	Covert
Facility	Covert / Covert		

Executive Summary

resolve the vibration issue may be to purchase this pump for replacement on the remaining units plus a spare (total of 5 new pumps). The pumps have a 62-week lead time and require progress payments. One pump will be purchased in 2025 to try in another location before executing this project.
Objectives:
Mitigate the risk of shutdown and/or derate by replacing the Circ water pump and motor. This particular pump is a large vertical turbine pump that runs continuously and is crucial to plant operation. The typical service life for a pump/motor of this type is 10 to 15 years, but the current pump has been operating for over 22 years. In 2023, a similar pump (2A) failed a shaft, resulting in a unit trip and forced outage on U2.

Planner Recommended Alternative:
Replace the Pump and Motor with rebuilt units (like new with warranty). The current motor in stock is new due to the 2B Motor being damaged beyond repair. A rebuilt pump is returned to like-new status at about 25% of the cost of a new one, with lead times of less than 12 weeks. Purchase one pump in 2025 to replace in Spring 2027. Once installed and proven, execute this project to purchase five additional pumps for replacing other units.
Other Alternative Considered:
Replace Pump and Motor with new components. The cost would be approximately $1.25 million for a new replacement, with a 56-week lead time as a new pump of this size would need to be built by the OEM.

Model Assumptions:
Calculation data supplied by the capacity forecast department:
$196,395 for a 2-day forced outage. $248,078 for a 2-week 60MW derate. CONE value: $130,930.

The 2A failure in October 2023 (pump/motor were 22 years in service) caused a forced outage that lasted 15 days. The unit trip caused a tube failure that extended the outage, so the full extent was not attributed to the pump.

The pumps were designed to be 50% capacity each. However, in the winter months, a single pump can operate and maintain adequate condenser cooling. During the summer months, a single pump results in approximately a 50 to 60 MW derate. Depending on the failure, it may result in a unit trip that has the potential to cause additional unit damage, as seen on unit 2 in October 2023.

Based on best engineering judgment with these types of pumps and plant experience with recent failures, the risk of failure is extremely high. Given the recent failure history of multiple pumps at the Covert site, we will assume a near-certain probability of failure.

Derate Assumptions:
60MW derate for 12 weeks. The probability of occurring is almost certain based on recent failure history for similar pumps.

Investment Overview

Project Details		
	Environmental Justice Area	No
	Estimate Class	Class 2
	Rate Case Mapping	Gas Generation
	EPM Managed	No
	Outage Type	Unit - Plant
	Scope	Replace pump and motor. Refurbish existing motor and keep as critical spare.
	Objectives	Mitigate risk of forced shutdown and/or derate by replacing Circ water pump and motor. This particular pump is a large vertical turbine pump that runs continuously and is important to plant operation. Typical service life for a pump/motor of this type is 10 to 15 years. Pump has been operating for > 22 years. in 2023 a similar pump in age and type failed a shaft (2A) resulting in unit trip and forced outage on U2. Plant engineering has contracted with HydroAire since Spring 2024 to determine root cause of high vibrations on current ITT pump installations and have not reached any conclusions that would allow for reliable modifications to existing assets. The purchase of a new asset once completely proven in the field is the next best option.
	Planner Recommended Alternative	Replace Pump and Motor with Rebuilt units (like new with warranty). The current motor in stock is actually new due to the fact 2B Motor was damaged beyond repair. A rebuilt pump is returned to like new status at a cost of about 25% new with lead times less than 12 weeks. Purchase 1 pump in 2025 (currently have budget) to replace in Spring of 2027. Once installed and proven execute this project to purchase 5 additional pumps for replacing other units. 2025: downpayment for 1 pump 150k 2026: Replace 3A pump and pay for the rest of the ordered pump - $1.1M 2027: Order 5 pumps, install 1 pump - $1.25M 2028: Receive 5 pumps, install 3 pumps - $3.25M 2029: Install final pump, stock 1 spare pump, 1 spare motor - $500k alternative option: Replace Pump and Motor with New. Cost would be ~ $1.25 million for new replacement and result in a 56 week lead time as a new pump this size would need to be built by OEM. We have a spare on site that will be installed in 2A October 2025. Then we will have at least a 36 week lead time to get our spare back because the impeller failed and that item is very long lead. So we will have Significant risk going into 2026. The pumps were designed to be 50% capacity each, however in the winter months a single pump can operate and maintain adequate condenser cooling. During the summer months a single pump result in approximately 50 to 60 MW derate (Single pump operation will result in 50 to 60 MW derate between April 1st and January 1st.). Depending on the failure it may result in a unit trip that has the potential to cause additional unit damage as seen on unit 2 in October 2023.

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN003012	**2025**	**5**	**Literal**

Investment Name	Scenario
CGS - U13 Circ Water pump replacements	**Draft**

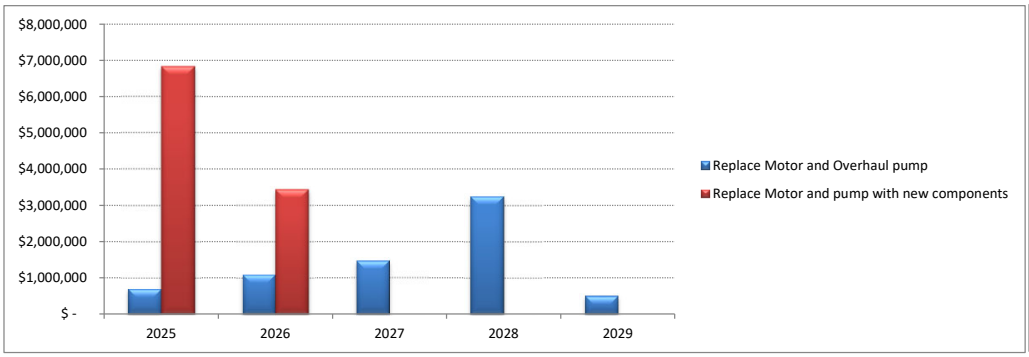
Value Function: **Consumers Energy Value Function**

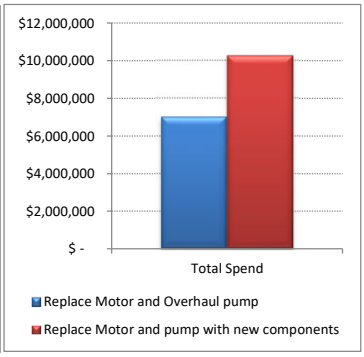
	Assumptions	Calculation data supplied by capacity forecast department. $445,293 for 5-day forced outage. $2,174,906 for a 12-week 60MW derate. Potential Capacity calculations were made using a conservative calculator provided by the capacity forecast team. Three-year impact on Capacity revenue is included in this number. The CONE value used for this model is $130,930. 75% of CONE was used for the calculations as customary. CONE value $130,930. Assume a risk of a 12-week 60MW derate plus a 5-day forced outage for the next 9 months. Near certain probability of realizing this risk based on failure history. Assume a 5-day forced outage risk after 9 months since a spare will be on site. Near certain probability of realizing this risk based on failure history.
Alternative Details	Replace Motor and Overhaul pump	Pull pump and replace with capital spare and install an overhauled pump (new motor) to make asset like new and avoid potential downtime.
	Replace Motor and pump with new components	Pull pump and replace with capital spare and install a new motor and pump to make asset like new and avoid potential downtime.

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
Replace Motor and Overhaul pump	Recommended	$ 7,008,355	5/1/2025
Replace Motor and pump with new components	Candidate	$ 10,253,737	5/1/2025

Name	Status	2025	2026	2027	2028	2029
Replace Motor and Overhaul pump	Recommended	$ 700,003	$ 1,100,000	$ 1,458,352	$ 3,250,000	$ 500,001
Replace Motor and pump with new components	Candidate	$ 6,822,974	$ 3,430,763	$ -	$ -	$ -





Forecasts - Draft (Replace Motor and Overhaul pump)

Account Type	2025	2026	2027	2028	2029
Capital	$ 629,988	$ 989,203	$ 1,312,517	$ 2,923,010	$ 449,687
Cost Of Removal	$ 70,015	$ 110,796	$ 145,835	$ 326,989	$ 50,313
O&M	$ -	$ -	$ -	$ -	$ -

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002925	**2026**	**4**	**Literal**

Investment Name	Scenario
Covert - HEPS/FAC/DAST Inspections (Capital)	**Draft**

Value Function	**Consumers Energy Value Function**

Covert - HEPS/FAC/DAST Inspections (Capital)

Investment Type	Generation	Planning Portfolio	Covert
Facility	Covert / Covert		

Executive Summary

This project aims to bring the Covert site into compliance with existing corporate governance on G-A-313, G-A-314, and G-A-315 programs. Compliance with these programs ensures the safe operation of the site and provides outage scheduling flexibility by transitioning from a potential 12-month operating certificate to 3-year operating certificates.
Scope:
The project involves performing HEPS/FAC/DAST inspections to ensure compliance with G-A-313, G-A-314, and G-A-315 programs.

Objectives:
The primary objective is to bring the site into compliance with the specified programs and enable the achievement 3-year operating certificates.The project is essential to maintain the ability to implement 3-year operating certificates. Failure to perform the required inspections would limit the unit to a 12-month operating certificate, necessitating a full inspection before the unit can be certified to operate.

Model Assumptions:
The project assumes the loss of an extended operating license interval, requiring approximately a 10-day outage each year along with the associated costs of performing required testing and certifications. The project is expected to result in cost savings of $2.5 million in O&M for annual boiler certificate inspections, assuming $50,000 for safety valve testing, drum inspections, etc.
Based on recent NDE results, if nothing is done, there is reasonable assurance that a pipe failure a pipe failure will occur with a 5% probability. It will be assumed that it will take 60 days of forced outage to recover from this scenario. This assumption is based on recent outage data.

Benefits:
The project allows for outage scheduling flexibility by moving away from a 12-month operating certificate, thereby reducing the frequency and cost of inspections and ensuring the continued safe operation of the site.

Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 2
	Rate Case Mapping	Gas Generation
	EPM Managed	No
	Outage Type	Unit - Plant
	Scope	Covert - HEPS/FAC/DAST Inspections
	Objectives	Bring the site into compliance with G-A-313, G-A-314, and G-A-315 programs and enable them to achieve 2- and 3-year operating certificates.
	Planner Recommended Alternative	Perform required inspections.
	Assumptions	Loss of extended operating license interval requiring roughly a 10-day outage every year along with the associated costs of performing required testing and certifications. cost savings of $2.5M O&M for annual boiler certificate inspections. Assumes $50k for safety valve testing, drum inspections, etc. Project allows outage scheduling flexibility by moving away from a 12-month operating certificate. Based on recent NDE results, if nothing is done, there is reasonable assurance that a pipe failure a pipe failure will occur with a 5% probability. It will be assumed that it will take 60 days of forced outage to recover from this scenario.
Alternative Details	Boiler safety program HEPS/FAC/DAST inspections	Boiler safety program HEPS/FAC/DAST inspections

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002925	2026	4	Literal

Investment Name: **Covert - HEPS/FAC/DAST Inspections (Capital)**

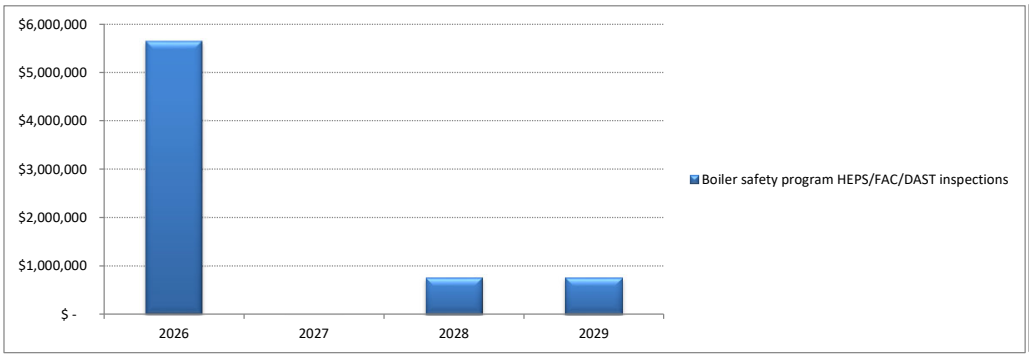
Scenario: **Draft**

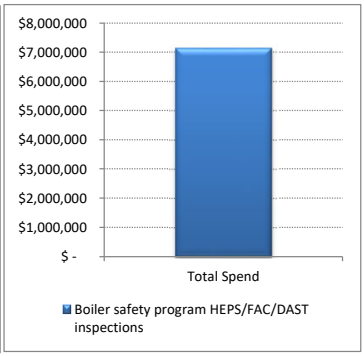
Value Function: **Consumers Energy Value Function**

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
Boiler safety program HEPS/FAC/DAST inspections	Recommended	$ 7,149,999	1/1/2026

Name	Status	2026	2027	2028	2029
Boiler safety program HEPS/FAC/DAST inspections	Recommended	$ 5,649,999	$ -	$ 750,000	$ 750,000





Forecasts - Draft (Boiler safety program HEPS/FAC/DAST inspections)

Account Type	2026	2027	2028	2029
Capital	$ 5,084,999	$ -	$ 675,000	$ 675,000
Cost Of Removal	$ 565,000	$ -	$ 75,000	$ 75,000
O&M	$ -	$ -	$ -	$ -

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002285	**2026**	**2**	**Literal**

Investment Name	Scenario
CGS – Replace Bleach Storage Tank, Dosing System, and Building	**Draft**

Value Function	**Consumers Energy Value Function**

Covert Generating station has utilized the sodium hypochlorite system since the system was brought online in 2004. During the past 21 years of operation, numerous repairs have been made to pumps, lines, valves, and building components to keep these systems in operation. The sodium hypochlorite system has over 60 documented failures resulting in chemical release and hazardous clean up situations. This system has gone beyond its expected life cycle and presents an increased risk of employee exposure and injury along with the risk of environmental contamination.

The current sodium hypochlorite bulk storage tank is in the same structure as the sulfuric acid bulk storage tank, only separated by a fiberglass wall. While the bulk storage tanks have served the plant since 2004, there has always been potential for a combined spill creating chlorine gas. By erecting a new sodium hypochlorite bulk storage tank away from the sulfuric acid bulk storage tank, the potential is greatly reduced.
The sodium hypochlorite dosing system (pumps, valves, piping, electronic controls) is degraded to the point of approaching damage beyond repair. On many occasions operators have discovered leaks. Vapors from sodium hypochlorite are dangerous and require operators to ensure this space is completely ventilated prior to entering the space. The current building is in a similiar condition and requires replacement.

Investment Type	Generation	Planning Portfolio	Covert
Facility	Covert / Covert		
Executive Summary	The project involves replacing the existing sodium hypochlorite bulk storage tank, dosing system and the building housing the dosing systems at the Covert Generating Company. The current sodium hypochlorite system, in operation since 2004, has experienced over 60 documented failures, leading to chemical releases and hazardous cleanup situations. The system has surpassed its expected life cycle, posing increased risks of employee exposure, injury, and environmental contamination. Objectives: The primary objective is to replace the aging sodium hypochlorite bulk storage tank, dosing system and housing structure to mitigate the risks associated with chemical spills and exposure to hazardous vapors. By relocating and separating the bulk sodium hypochlorite tank from the bulk sulfuric acid tank (both tanks are currently housed in same building only separated by fiberglass wall), the potential for a combined spill creating chlorine gas is significantly reduced. The recommended alternative is to replace/relocate the sodium hypochlorite bulk storage tank, replace/relocate the sodium hypochlorite dosing system including headers from the dosing system to the three cooling towers, and replace/relocate the sodium hypochlorite fiberglass housing/building. Draft Forecast$2,158,858 Between Jan 2026 and Dec 2027 Model Assumptions: There is a 10% probability of realizing a $50,000 to $150,000 risk based on discussions with plant personnel and equipment history. Additionally, there is a 3% chance of realizing a risk of a recordable injury due to exposure to chlorine gas from a potential mix between sulfuric acid and sodium hypochlorite.		
Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	No
	Outage Type	Site
	Scope	CGS - Plant Replace Sodium Hypo storage tank and Building Replace tank. Replace pump skid and building.
	Objectives	CGS - Plant Replace Sodium Hypo storage tank and Building Benefits: Cooling tower bleach injection system material condition is improved by replacement with more robust materials and safety concerns are addressed by relocating storage vessel. Performance of cooling towers is improved by more efficient use of biocide. Necessity / Current issues and Deficiencies: 1. Pipe materials: the existing CGS cooling tower biocide (bleach) pump skid and associated piping are in poor material condition, have been source of multiple failure in the past, and continue to be at significant risk. CPVC piping joints have degraded due to oxidation. Replacing all CPVC with PVDF (Kynar Pipe or similar) will significantly reduce risk of leaks and improve material condition. Kynar pipe uses thermal welds as opposed to glues. 2. Location: the current locations of the bleach bulk storage tank and pump skid are too close to the cooling tower sulfuric acid injection bulk tank and pump skid. The bulk bleach and acid storage tanks are in the same building and only separated by an un -sealed fiberglass wall with the bleach tank fill line routed directly through the sulfuric acid bulk tank room. Bleach mixed with any acid will release a toxic chlorine gas. Relocating the bleach bulk tank and pump skid to an area NE of the ammonia storage tank will provide better physical separation of the two chemicals and significantly reduce risk of a catastrophic environmental/safety incident. Additionally, both bleach and acid tanks are FRP-type materials with limited life; typically, 10-15 years. The tanks were installed in ~2003. See sketch below. 3. Bulk storage tank orientation: The existing 6000-gal bleach tank is oriented horizontally and located about 4-5 feet below grade whereas the pump skid is at grade. Orienting the storage tank vertically and at grade will improve pump performance (provide consistent positive head pressure). 4. Injection point: The current layout routes bleach to a single injection quill located on the SW end of each tower (discharge end). Rerouting the injection points closer to the NE end of each tower and injecting bleach via an injection manifold vs. a single quill will improve biocide performance. 5. Pipe Chase: The current system design routes bleach and sulfuric acid injection headers in the same pipe-chase from the pumps skids to towers. Separating the bleach injection header from the sulfuric acid injection header will significantly reduce risk of serious environmental/safety incidents. Consider double-walled piping for the bleach headers routed to C/Ts for leak detection. 6.
	Planner Recommended Alternative	Replace storage tank and building.
	Assumptions	Potential for chemical spill exists. 10% probability of realizing a 50k-150k risk based on discussions with Plant personnel and equipment history. Risk of injury exists from exposure to chlorine gas from a potential mix between sulfuric acid and sodium hypoclorite. 3% chance of realizing a risk of a recordable injury (Conservative estimate).
Alternative Details	Replace H2SO4 and NaOCl bldg	Replace H2SO4 and NaOCl bldg

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002285	**2026**	**2**	**Literal**

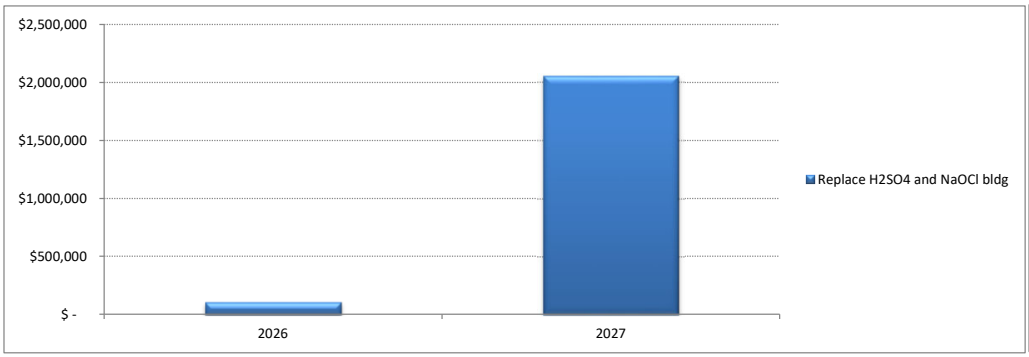
Investment Name	Scenario
CGS – Replace Bleach Storage Tank, Dosing System, and Building	**Draft**

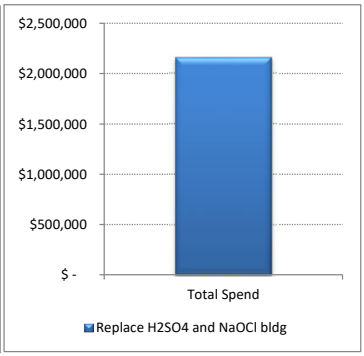
Value Function	**Consumers Energy Value Function**

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
Replace H2SO4 and NaOCl bldg	Recommended	$ 2,158,858	1/1/2026

Name	Status	2026	2027
Replace H2SO4 and NaOCl bldg	Recommended	$ 102,803	$ 2,056,055





Forecasts - Draft (Replace H2SO4 and NaOCl bldg)

Account Type	2026	2027
Capital	$ 92,522	$ 1,850,450
Cost Of Removal	$ 10,280	$ 205,606
O&M	$ -	$ -

Concept Approval

Karn 3&4 Combustion Air Heaters

Date: 07/24/2024

Prepared by: Paul Ohep



Figure 1. D.E. Karn generating station

Executive Summary

The D.E. Karn 3&4 Generating Units rely on steam-to-air heat exchangers called combustion air heaters to preheat the air entering the boiler. This process is crucial for optimizing combustion efficiency and maintaining emissions within acceptable opacity limits, especially for Karn Units #3 and #4, which lack other means of controlling particulate matter output.

Key Issues

- **Tube Failures**: Over the last five years, Units #3 and #4 have experienced repeated tube failures, leading to forced outages and reduced efficiency.
- **Operational Impact**: The reduced efficiency from plugging failed tubes has caused significant operational de-rates, including a 68 MW de-rate for Karn Unit #3 from fall 2023 to spring 2024.

Engineering Evaluations

- **Historical Repairs**: Multiple outages for repairs since 1984, with replacements and repairs showing varying success.
- **Recent Testing**: 2024 eddy current testing revealed over 25% of the tubes in non-replaced sections of Unit #4 are plugged, necessitating replacement.

Alternative Solutions

1. **Do Nothing – Cost: $23+ million.**
    - **Risks**: High probability of repeated failures, leading to extended de-rates and forced outages, substantial financial losses, and regulatory compliance challenges.
2. **Plugging Individual Failed Tubes – Cost: Up to $10 million**
    - **Risks**: High recurrence risk of tube failures, frequent outages, cumulative financial impact of at least $10 million over seven years, and potential non-compliance with opacity and emissions standards.
3. **Complete Combustion Air Heater Replacement – $4.4M for Karn 3, $4.4M for Karn 4**
    - **Cost**: $8,800,000 total for replacing the air heaters in both units (12 heaters total).
    - **Benefits**: Enhanced reliability, improved efficiency, and ensured regulatory compliance, avoiding projected capacity revenue losses of over $23 million. This proactive approach addresses the root cause of failures, providing a long-term solution for operational efficiency and cost savings.

Conclusion

The "Do Nothing" option presents significant financial, operational, and regulatory risks. Plugging individual failed tubes offers a short-term, high-risk solution with substantial cumulative costs. The complete replacement of combustion air heaters in both Karn Units #3 and #4 is the most viable long-term strategy, ensuring reliable performance, compliance with regulations, and significant cost savings.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$8,800,000 ($4.4M for Karn 3, $4.4M for Karn 4)

Proposed Start Implementation Year and project span

2024, four-year span. Completion in 2027.

Rate Case Summary

- Karn 3 project **is** included in the current electric rate case. The bridge period amount is $2.2M
- Karn 4 project **Is NOT** included in the current electric rate case.

Problem Description

The D.E. Karn Generating Station, which utilizes natural gas and oil, employs steam-to-air heat exchangers known as combustion air heaters to preheat the ambient air entering the boiler. This preheating process is essential for optimizing combustion efficiency. Specifically, Karn Units #3 and #4 rely heavily on consistent air intake temperature to fine-tune the combustion air-fuel mixture, crucial for maintaining emissions within acceptable opacity limits and ensuring efficient heat rates as they do not have any other means of controlling the output of particulate matter.

Key Issues

- **Tube Failures**
  - Units #3 and #4 have repeatedly experienced tube failures in the combustion air heaters over the last five years.
  - Failed tubes require immediate plugging and can result in forced outages if they trip the unit or necessitate immediate removal from service.
  - Plugging reduces the efficiency of the air heaters, leading to operational de-rates and inefficiencies.
- **Operational Impact**
  - Reduced efficiency of the air heaters due to tube plugging leads to significant operational de-rates.
  - From fall 2023 until spring 2024, Karn Unit #3 operated with a 68 MW de-rate due to two combustion air heater sections being out of service.

Engineering Evaluations

Extensive evaluations and testing have highlighted the necessity for addressing the issues with the combustion air heaters:

- **Historical Outages and Repairs**
  - Multiple outages have been required for repairs from 1984 through 2024.
  - Records indicate replacements in 1988 and 1990, with further repairs in 1999 showing minimal tube plugging in those sections.
- **Recent Eddy Current Testing (2024)**
  - Testing revealed that over 25% of the tubes in the non-replaced sections of Unit #4's air heater are plugged.
  - Industry standards suggest considering replacement when more than 10% of the surface area is plugged.

Conclusion

The recurrent tube failures and significant plugging in the combustion air heaters of Karn Units #3 and #4 have led to efficiency losses and operational de-rates. The historical data and recent testing highlight the urgent need for comprehensive solutions to address these issues, ensuring regulatory compliance and operational efficiency.

Alternative Solutions/Alternatives Considered

1. Do Nothing – Cost: $23+ million

Choosing the "Do Nothing" option for addressing the combustion air heater issues in Karn Units #3 and #4 presents significant risks and operational challenges. Historical data and predictive maintenance records highlight the recurring nature of these failures and their substantial impact on plant performance.

Historical Forced Outages and De-rates

1. **Frequency of Forced Outages/De-rates**
    a. **Past Incidents:** There have been multiple forced outages and de-rates in the last five years due to issues with the combustion air heaters in Karn Units #3 and #4.
    b. **Duration of Forced Outages:** Forced outages typically lasted for 2 weeks.
    c. **Duration of De-rates:** The last de-rate in unit 3 extended over a period of 6 months from fall of 2023 until spring of 2024.
    d. **Magnitude of De-rates:** The de-rates have caused a reduction of 68 MW in output.
    e. **Timing:** Forced outages occurred in late summer, while the extended de-rate lasted from fall until spring.

2. **Projected Impact of Future Failures**
    a. **Expected De-rate Magnitude:** Future failures are anticipated to result in a de-rate of 68 MW for either Karn 3 or 4.
    b. **Duration of De-rate:** The de-rate will persist until an outage allows for the failed tubes to be plugged or replaced. For cases where 2 out of 3 sections are out of service, the de-rate will last until the combustion air heaters are replaced. For Karn Unit #3, due to the extensive lead times for tube bundles and headers, the forced outage is expected to last approximately 5 months.

Procurement and Installation Challenges

- **Lead Time for Replacement Parts:** The lead time for obtaining replacement fin tubes is approximately 5 months from the receipt of a purchase order.
- **Installation Duration:** The installation duration for the replacement components would extend the de-rate/outage period, incurring additional costs compared to a planned replacement.
- **Seasonal Considerations:** Karn Units #3 and #4 operate as peaker plants, meaning they are primarily utilized during periods of high demand and high power prices. Forced outages or de-rates occurring during these peak periods (late summer and high-demand seasons) can severely impact the plant's ability to generate revenue and meet energy demands.

Risk Analysis of Failure

- **Probability of Failure:** Based on historical performance and current predictive maintenance records, including thermography, vibration analysis, and eddy current testing, failures are very likely to occur within the next 1-3 years.
- **Financial Impact:** Prolonged de-rates and outages during peak periods when the plant is expected to operate can lead to substantial financial losses due to reduced power generation and higher costs of emergency repairs.

Regulatory Compliance

Failure to maintain emissions within acceptable opacity limits due to inconsistent air intake temperatures can result in non-compliance with environmental regulations.

- **Opacity Permit Requirements potential violation:** Our de-rate is based on staying below the opacity limit of our flue gas output. Without the project, we will not be able to reach full load without violating our opacity permit requirements for particulate matter.
- **Specific Regulations:** The opacity permit requirements, which control the emissions of particulate matter, will be violated if the combustion air heaters are not operating within their design specifications.
- **Past Violations:** We have violated these requirements in the past.
- **Consequences:** Past violations have led to regulatory scrutiny.
- **Fines:** Non-compliance with the opacity permit can result in significant fines.
- **Estimated Costs:** The exact cost of fines can vary, but non-compliance typically incurs substantial financial penalties.
- **Enforcement Actions:** If the opacity permit is violated, there is a risk of enforcement actions, up to and including the potential revocation of our operating license.
- **Impact:** Revoking our operating license would lead to an immediate and indefinite shutdown of the plant, severely impacting our operational capacity and financial performance.

Capacity Value Potential Loss Impacts - $23M+ in potential capacity losses:

If no action is taken to address the issues with the combustion air heaters in Karn Units #3 and #4, there is a high potential for capacity revenue loss. The following scenarios outline the potential financial impacts under different forced outage and de-rate conditions.

Scenario 1: Five-Month Forced Outage

In the event of a five-month forced outage due to the need for replacing the entire combustion air heater, the following capacity losses are anticipated. This scenario assumes the outage occurs at Karn 3, and the table below details the projected capacity loss and associated revenue loss over three years.

Applying the same parameters as before but extended the timeframe to 5 months rather than 2 weeks. This scenario projects a loss of 40 ZRCs over a span of 3 years, with an associated capacity value impact of approximately $23.5 million for a single unit.

Five-Month Forced Outage scenario.

Year	Planned Capacity (ZRCs)	Lost Capacity (ZRCs)	Delta Capacity (ZRCs)	Loss Capacity Revenue
2023	288.1	0	288.1	$0
2024	288.1	0	288.1	$12,142,298
2025	288.1	39.992	248.108	$3,813,284
2026	288.1	39.992	248.108	$3,813,284
2027	288.1	39.992	248.108	$3,813,284
2028	288.1	0	288.1	$0
Total				**$23,582,149**

Table 2. Capacity losses summary for Karn single unit five-month forced outage.

Scenario 2: Continuous 68 MW De-rate Until 2031

If it is decided not to repair a potential failure and to operate with a 68 MW de-rate until 2031, the following capacity losses are anticipated. This scenario assumes a 68 MW de-rate at Karn 3 and utilizes a capacity value at 75% of CONE/ZRC. The yearly cost would be approximately $2.6 million, amounting to $17,984,981 over 7 years.

CONE = $127,135

75% CONE = $95,351

Table 3: Capacity cost summary for a 68MW single unit derate:

	ICAP	ZRC
Summer:	594	216
Fall:	596	254
Winter:	613	365
Spring:	602	118
Average:	601	238
% ZRC		40%
MW Risk		68
ZRC Risk		27
Capacity Risk		$ 2,569,283

Conclusion

The “Do Nothing” option presents significant risks and consequences. The historical data and predictive maintenance records indicate a high probability of repeated failures, leading to extended de-rates and forced outages. These issues result in substantial financial losses, operational inefficiencies, and potential regulatory compliance challenges. The extended lead times for procuring replacement parts further exacerbate the situation, making emergency repairs costlier and prolonging the outage periods. Consequently, not addressing the combustion air heater issues proactively can lead to critical operational disruptions, especially during peak demand periods.

2. Plugging individual failed tubes – Cost: Up to $10M

This option involves plugging individual failed tubes in the combustion air heaters of Karn Units #3 and #4 as they occur. This approach provides a short-term solution to manage immediate failures but comes with significant operational and financial risks due to the likelihood of repeated failures and subsequent forced outages. This approach will result in a forced two-week outage per incident.

Process and Cost

- **Detection and Repair:** Crews will enter the space to identify the failed tubes through testing, plug the identified tubes, and return the unit to service.
- **Outage Duration:** Each repair cycle will necessitate a forced outage of approximately 2 weeks.
- **Labor Cost:** The typical cost for each outage, including contractor labor and associated expenses, is estimated at $30,000 per event.

- **Capacity value Costs:**
  - Each two-week forced outage carries an additional cost of $1,053,670 in lost capacity revenue.
  - For the purposes of this analysis, typical losses from a seasonal or current accreditation standpoint were considered. The figures for Karn 3 were employed in the computations due to its greater capacity accreditation. This involved a straightforward computation of lost ZRCs. However, if Tier 2 hours are during peak times, the impact could be significantly more severe.
  - The financial impact would result in ~4 ZRC loss for 3 years, equating to ~$1.1M loss. This again, is worst case scenario for Karn 3 only; if the failure happens on both units simultaneously, it would be around double the losses.
  - Table 1 below details the projected capacity loss and associated revenue loss over three years.

Two-Week Forced Outage scenario capacity losses.

Year	Planned Capacity (ZRCs)	Lost Capacity (ZRCs)	Delta Capacity (ZRCs)	Loss Capacity Revenue
2023	288.1	0	288.1	$0

Year	Planned Capacity (ZRCs)	Lost Capacity (ZRCs)	Delta Capacity (ZRCs)	Loss Capacity Revenue
2024	288.1	0	288.1	$0
2025	288.1	3.683	284.416	$351,223
2026	288.1	3.683	284.416	$351,223
2027	288.1	3.683	284.416	$351,223
2028	288.1	0	288.1	$0
Total				**$1,053,670**

- Table 1. Capacity losses summary for Karn single unit two-week forced outage

Frequency and Impact of Repairs

- **Immediate Recurrence Risk:** After the unit is returned to service, there is a high likelihood of additional tube failures occurring shortly thereafter, potentially leading to repeated forced outages similar to the incidents experienced in 2022.
- **Operational Disruption:** The repeated need for repairs can lead to significant operational disruptions and inefficiencies, with frequent outages impacting overall plant performance and reliability.

Detailed Considerations

- **Cumulative Financial Impact:**
  - Over the next seven years, it is expected that this scenario will occur around once a year and potentially more frequently after year 5, leading to a cumulative cost of around $10 million at a minimum when considering the likelihood of repeat failures.
- **Operational Impact**
  - **Efficiency Loss:** Continuous plugging of individual tubes reduces the overall efficiency of the combustion air heaters, leading to de-rates and suboptimal performance.

Summary

Advantages:

- **Lower Immediate Cost:** Individual repair events are relatively low-cost ($30,000 per outage + ~$1M in capacity costs).
- **Quick Return to Service:** Units can be returned to service relatively quickly (2 weeks per event).

Disadvantages:

- **High Recurrence Risk:** High probability of subsequent tube failures leading to repeated outages.
- **Operational Disruption:** Frequent outages disrupt power generation and reduce overall efficiency.
- **Cumulative Cost:** Over time, the cumulative financial impact of repeated outages, including capacity revenue losses, can be significant, amounting to a minimum of $10 million over seven years.
- **Regulatory Compliance Risk:** Continued operation with frequent failures may risk non-compliance with opacity and emissions standards.

3. Combustion Air Heater replacement: $4.4M for Karn 3, $4.4M for Karn 4

Overview

Given the significant and recurring issues with the combustion air heaters in Karn Units #3 and #4, a comprehensive replacement of the air heaters is proposed. This option addresses the root cause of the frequent failures and operational inefficiencies, providing a long-term solution to ensure reliable performance and regulatory compliance. The total cost for replacement is estimated at $5 million for Karn Unit #3 and $3 million for Karn Unit #4.

Total Cost of Replacement

- **Karn Unit #3:** $4,400,000
- **Karn Unit #4:** $4,400,000
- **Total Replacement Cost:** $8,800,000

Justification for Replacement

1. Historical Issues and Recurring Failures

- **Frequent Outages:** Karn Units #3 and #4 have experienced multiple forced outages and de-rates over the past five years due to tube failures in the combustion air heaters.
- **High Maintenance Costs:** The repeated need for repairs, including plugging individual tubes, has led to significant maintenance costs and operational disruptions.

2. Long-Term Benefits of Replacement

- **Enhanced Reliability:** Replacing the combustion air heaters will eliminate the frequent tube failures, ensuring consistent and reliable operation of the units.
- **Improved Efficiency:** New air heaters will restore the units to their optimal performance levels, reducing the risk of de-rates and maximizing power generation capacity.
- **Regulatory Compliance:** Ensuring the air heaters operate within their design specifications will help maintain emissions within acceptable limits, complying with regulatory requirements and avoiding potential fines.
- **Significant Cost Savings:** By investing $8 million in the complete replacement of the combustion air heaters at Karn Units #3 and #4, Consumers Energy can avoid projected capacity revenue losses of over $23 million if no action is taken. This proactive approach ensures long-term operational reliability, efficiency, and regulatory compliance, ultimately providing a cost-effective solution compared to the cumulative costs and risks associated with the "Do Nothing" or emergent repair options.

Scope of Work

Replace the Combustion air heaters for both Karn 3 and 4 units. Below is a timeline indicating the years and installations of Combustion air heater sections for Karn 3 and 4.

		K3	K4	Plus
2025	Spring		Combustion Air Heater (AA & AC Sections)	Tube and headers order
	Fall		Combustion Air Heater (AB Section)	
2026	Spring		Combustion Air Heater (BA & BC Sections)	
	Fall	Combustion Air Heater (AA & AC Sections)		
2027	Spring	Combustion Air Heater (AB & BA Sections)	Combustion Air Heater (BB Section)	

Funding and Timing

- Funding has been previously committed for this project: $1.3M in 2024
- No outage is required for this project.
- Desired implementation year: 2024, last year spend 2027

System Engineer

- System Engineer: Craig Jeske

Conceptual Estimate

Year	Loaded Cost	Description
2024	**$1,300,000**	Engineering and install for K3 BB, BC sections.
2025	**$2,500,000**	Engineering and install for K4 AA, AB, AC sections, tube and headers order for 2026.
2026	**$2,850,000**	Engineering and install for K3 AA, AC, sections. Engineering and install for K4 BA, BC sections.
2027	**$2,150,000**	Engineering and install for K3 AB, BA, sections. Engineering and install for K4 BB section.

Total Cost: $8,800,000

Asset Strategy Approval Comments

The Asset Strategy Group strongly recommends approval based on cost-benefit analysis.

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN001769	**2026**	**1**	**Literal**

Investment Name	Scenario
Karn 4 - Ductwork Exp Joint Replacement - ID Fans to Stack	**Draft**

Value Function	**Consumers Energy Value Function**

All expansion joints between the ID Fans and the Stack are suspected to be severely failed and past end of life based upon condition of expansion joints found during the Karn 3 Breeching project.
The furnace flue gas exits the boiler and gets pulled by the induced draft fan out through duct work in negative pressure until it reaches the Induced draft fan. Once exiting the induced draft fan the flue gas is pushed under pressure up the ductwork to the chimney stack where the proposed expansion joint replacement is located. When the flue gas is under pressure it is an environmental regulatory risk to leak into the atmosphere.
If there are leaks in the outlet side of the ID fan duct to the chimney, unmonitored flue gas is escaping to the atmosphere and violating the Operating Permit. Regulatory fines could be assessed up to removing the unit from service.

Investment Type	Generation	Planning Portfolio	Karn - Gas/Oil Generation
Facility	Karn / Karn		

Executive Summary

Project Overview
The project aims to replace all expansion joints between the ID Fans and the Stack, which are suspected to be severely failed and past their end of life. This is based on the condition of expansion joints found during the Karn 3 Breeching project. The furnace flue gas exits the boiler and is pulled by the induced draft fan through ductwork under negative pressure until it reaches the fan. Once exiting the fan, the flue gas is pushed under pressure up the ductwork to the chimney stack. Leaks in this system pose an environmental regulatory risk and could result in regulatory fines or removal of the unit from service.

Draft Forecast$2,620,001 Between Jan 2026 and Dec 2026

Scope
Replace all expansion joints and entry doors between the ID Fans and the stack.
Objectives
Mitigate forced shutdown and regulatory risk.
Return the equipment to its original standard.
Ensure regulatory compliance with environmental operating permits.
Alternatives
Recommended: Replace ductwork.
Historical Engineering Inspections: Several repairs have been made to the ductwork based on past inspections.
Age of Current Expansion Joints: The current Karn 4 expansion joints are 50 years old.
Regulatory Compliance: Expelling flue gases to the atmosphere bypasses the Continuous Emissions Monitoring System, leading to EGLE violations and potential shutdowns until resolved.
Model Assumptions
If no action is taken and leaks are found, the operating permit for the unit could be jeopardized, leading to environmental fines and forcing both units offline.
There is a 75% probability of expansion joint failure causing unmonitored flue gas to enter the atmosphere, resulting in a 300 MW derate followed by a 1-week 1221 MW derate with both Karn 3 and 4 down for repairs.
Performing this project will avoid O&M inspection costs of up to $20K, including scaffolding and unit outage expenses. Repairs based on inspection findings could add a minimum of $30K. The total $50K will be divided over 6 years, amounting to $8333 annually.

Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Peakers
	EPM Managed	No
	Outage Type	Unit - Plant
	Scope	This project will replace all expansion joints and entry doors between the ID Fans and the stack.
	Objectives	mitigate forced shutdown and regulatory risk Returning the equipment to original standard. Ensuring regulatory compliance with our environmental operating permit.
	Planner Recommended Alternative	replace expansion joint Historical engineering inspections have led to several repairs in the duct work Age of current Karn 4 expansion joints are is 50 years The expelling of flue gases to the atmosphere/environment bypasses the Continuous Emissions Monitoring System which will cause EGLE violation that lead to shutting the unit down until the condition is resolved.
	Assumptions	If chosen to do nothing, and leaks in the expansion joint are found the operating permit for the unit could be in jeopardy as well as environmental fines. Because of the location, both units would be forced offline. 75% probability of expansion joint failure causing flue gas to enter the atmosphere unmonitored makes it high consequence in which would be an immediate 300 MW derate followed by a 1-week 1221 MW derate with both Karn 3 and 4 down for an inside repair. By performing this project, we will avoid O&M inspection of the ductwork (up to $20K) which includes a large expense of scaffolding and a unit outage. Repairs based on inspection findings could be an additional $30K minimum. $50k will be divided by 6 years for a yearly amount of $8333.
Alternative Details	replace duct work	replace duct work

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN001769	**2026**	**1**	**Literal**

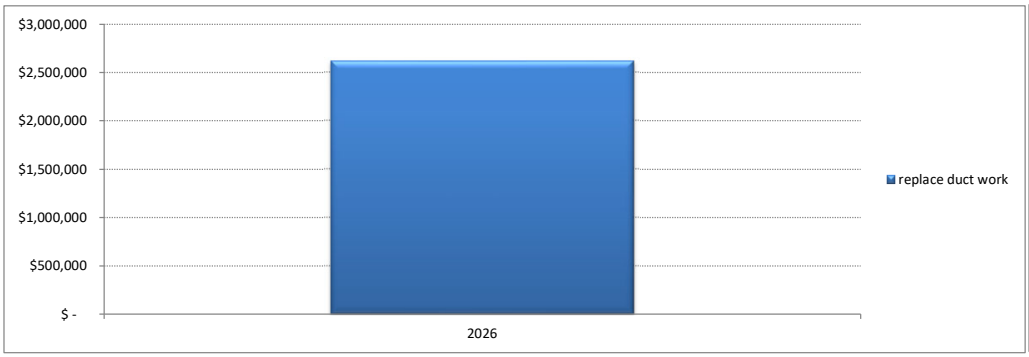
Investment Name	Scenario
Karn 4 - Ductwork Exp Joint Replacement - ID Fans to Stack	**Draft**

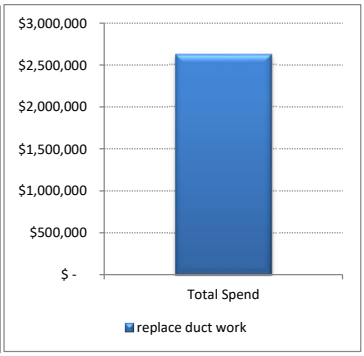
Value Function	**Consumers Energy Value Function**

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
replace duct work	Recommended	$ 2,620,001	1/1/2026

Name	Status	2026
replace duct work	Recommended	$ 2,620,001





Forecasts - Draft (replace duct work)

Account Type	2026
Capital	$ 2,358,001
Cost Of Removal	$ 262,000
O&M	$ -

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN003034	**2024**	**3**	**Literal**

Investment Name	Scenario
Karn 4 post-fire remediation 2025-2026	**Draft**

Value Function	**Consumers Energy Value Function**

In the original Karn 3&4 plant design, startup transformer bank (#8), fed by the grid, is used to power up large fans and pumps until the unit is synchronized and starts putting Megawatts out on the grid thru the main Generator Step-Up Transformer. At that point, the plant is switched over to feed its own power thru the station power transformers and Megawatt output may be increased to full load.

During the 2025 Karn 4 main transformer (GSU) fire, the unit 4 station power transformers X, Y and Z nearby also suffered damage. The bus connecting the station power transformers to the plant was burned away. This bus was attached to the transformers thru porcelain terminal bushings. The porcelain was busted as the bus fell down. The internal windings of these three transformers tested ok after the fire, but the bushings need to be replaced to make them useable. Furthermore, the heat of the fire has deformed some of the oil seals on the transformers. Between these small oil leaks and the compromised bushings, it is urgent that this be addressed before winter, when cold temperatures could make leaks bigger, risking more oil spilling out and moisture contamination getting in.

The #8 bank is sized to provide Unit 4 station power and start Karn 3; however it is not sized to provide station power for both units while online. Thus, Karn 3 station power is critical to achieving full load. If one of unit 3 station power transformers failed, Karn 3 would be derated half load until the failed transformer was replaced. Procuring a replacement transformer typically takes up to three years.

Investment Type	Generation	Planning Portfolio	Karn - Gas/Oil Generation
Facility	Karn / Karn		
Executive Summary	The 2025 Karn 4 GSU fire damaged three Unit 4 station power transformers (X, Y, Z), destroying the connecting bus, breaking porcelain bushings, and deforming transformer oil seals. While internal windings remain intact, the compromised bushings and seals pose an urgent reliability and environmental risk—particularly heading into winter, when moisture intrusion and oil leaks could render all three transformers unusable. Loss of these transformers would eliminate critical station power capacity, increase dependency on the aging #8 cranking transformer, and create operational derates of up to 300 MW for multiple years. Objectives Mitigate forced-outage risk, Prevent equipment loss from moisture contamination, Restore reliable and redundant station power capability Reduce operational dependency on the #8 cranking transformer Operational Performance & Outage Avoidance Reduces downtime from 3 months to ~3 weeks if a Karn 3 transformer fails. Creates three like-kind spares for Karn 3, replacing the spare lost in the fire. Avoids multi-year (up to 3-year) 300 MW derates at Karn 3. Environmental Protection Eliminates oil-spill risk from heat-damaged seals and valves. Prevents costly soil contamination events similar to the $136k cleanup after the GSU fire. System Readiness & Plant Performance Enables zero-downtime response to a station power transformer failure once the bus is rebuilt. Reduces the failure probability of the 50-year-old #8 cranking bank (from ~75% to 25%). Restores original design configuration allowing Karn 4 to reliably supply its own station power with controllable voltage for critical plant loads. Improves stability for critical auxiliaries (fans, pumps, compressors, etc.) that were challenged during cranking-bank operation. Planner Recommended Alternative Avoids the need for a costly spare transformer purchase ($2M-$5M based on recent similar projects) Avoids 300 MW derates associated with multi-year transformer procurement Model Assumptions and Risk Considerations #8 cranking bank is 50 years old (designed for 20) and now carries full auxiliary load, with an estimated 50% failure probability within six years. If the cranking bank fails, Unit 4 would be unavailable for years while a replacement is procured. If bushings are not replaced, winter moisture intrusion will destroy all three Unit 4 transformers, costing ~$2M each plus multi-year derates. Oil-seal degradation is expected to worsen in winter (90% probability), raising risk of environmental contamination and cleanup costs.		
Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 2
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Unit - Plant
	Scope	replace transformer
	Objectives	mitigate forced outage risk Benefits of this project include: Restore three station power transformers to usable condition. Life extension by replacing parts worn out by 50 years of service. Significantly reduce the chance of in service failure by installing new bushings. Prevent damage to the transformer windings by changing bushings now, rather than wait for moisture to be pulled in during winter temperature drops. Reduce down time from 3 months to 3 weeks in the event that a Karn 3 station power transformer fails. Serve as three like and kind spare transformers for Karn 3, replacing the spare station power transformer that was destroyed in the fire. By being identical to the Karn 3 transformers in service, it simplifies and minimizes cost of transformer(s) swap if needed. Eliminate the environmental risk of oil spill by replacing oil seals and valves. Make the transformers ready for reconnect to the plant following replacement of the bus damaged by fire. Benefits of this final phase of restoration include: Further reduction of downtime for failure of a station power transformer from 3 weeks to zero. By having both Karn 3 and Karn 4 station power connected, one of them could trip for a single transformer failure and station power for that unit would be transferred back to the cranking transformer bank, allowing full load of both units to be sustained. Relief for the cranking transformer bank from having to spare Karn 4 station power. This would reduce the chance of failure for the 50 year old cranking bank from 75% to 25%. Restoration of original plant configuration to allow plant to feed its own station power to Karn 4 so that it can reliably power critical auxiliary loads without voltage drop.

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Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN003034	**2024**	**3**	**Literal**

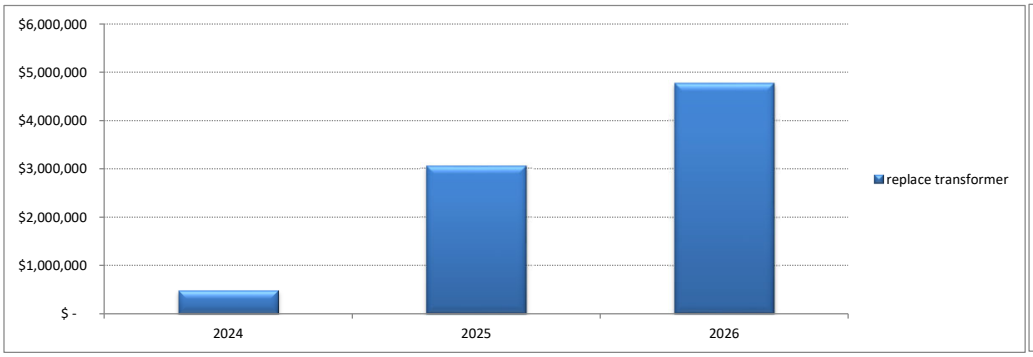
Investment Name	Scenario
Karn 4 post-fire remediation 2025-2026	**Draft**

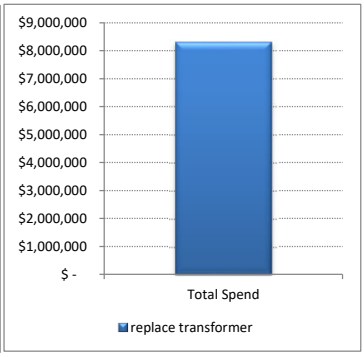
Value Function	**Consumers Energy Value Function**

	Planner Recommended Alternative	Replace bushings in Unit 4 station power transformers: Lowest cost option providing benefit the soonest. Avoids the $2M capital cost to buy a new spare transformer and avoids the O&M cost of being derated 300 MW for three years and avoids the added cost of engineering a different style spare transformer install if needed. Electrical Auxiliary Load Calculations by Commonwealth Associates Inc. dated April 6, 1972 show that the #8 cranking bank is sized to spare unit 4 and start unit 3. A test run demonstrated unit 4 can reach full load on the cranking bank, but as of this writing, starting unit 3 at the same time has not been attempted. During the test run, voltage on the 480V buses was depressed enough to reduce the performance of the instrument air compressor and contribute to a unit trip. Running on the cranking bank, voltage in the plant is subject to the condition of the system; we cannot adjust it especially now that Karn 1&2 is decommissioned. Whereas if the plant is running on its own station power, the voltage can be adjusted by adjusting generator voltage. Thus, the plant was designed to operate on its own station power as a more reliable and optimum voltage source for the critical loads such as boiler fans, vacuum pumps, condensate pumps, circulating water pumps, air compressors, etc. The #8 cranking bank was tested in 2024 and found to be in fair condition considering it is 50 years old and was designed to last 20 years. The long life is attributed to the infrequent loading of the bank only during startups. Now that we are depending on it to carry full auxiliary load of a unit, this elevates the risk of an end of life failure.
	Assumptions	If the #8 cranking bank failed, the only option is to backfeed thru a unit. It could take a couple weeks to build scaffold and remove generator links from Unit 4, so that it could be used to backfeed power for starting Unit 3. At that point Unit 4 would be unavailable for at least 3 years while a replacement cranking transformer is procured. 50% probability of failure in the next 6 years being that these are 50 years old. If the bushings are not replaced in the Unit 4 station power transformers, moisture will get into the windings this winter, resulting in a total loss of the X, Y, Z transformers. To replace these transformers, it would cost close to $2M each and take three years. In the event that one of the Karn 3 station power transformers fails, Karn 3 would be derated to half load (300MW) for 3 years. These transformers are 50 years old, twice exceeding their design life. So I give it a 50% chance of failure in the next 6 years. Also, if the bushings are not replaced, the slow oil leaks from the transformers observed now, could turn into large leaks at some point during the winter when seals shrink further. I give this a 90% chance of happening. While the transformers are in containment, that containment is filled with earth that would have to be disposed of and replaced if soaked in oil. Contaminated soil cleanup after the Karn 4 GSU fire cost $136k.
Alternative Details	replace transformer	replace transformer

Alternative Spend Profile

Name	Status				Total Spend			Alternative Start Date	
replace transformer	Recommended				$ 8,313,147			6/1/2024	
Name	**Status**	**2024**	**2025**	**2026**					
replace transformer	Recommended	$ 485,711	$ 3,054,437	$ 4,773,000					





Forecasts - Draft (replace transformer)

Account Type	2024	2025	2026
Capital	$ 437,140	$ 2,748,993	$ 4,295,853
Cost Of Removal	$ 48,571	$ 305,444	$ 477,147
O&M	$ -	$ -	$ -

Docusign Envelope ID: 03B3A894-68C9-4347-A307-D20C47324D10

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Concept Approval

Karn 4 ID Fan Inlet Dampers

Date: 10/07/2024

Prepared by: Paul Ohep



Figure 1. D.E. Karn generating station

Docusign Envelope ID: 03B3A894-68C9-4347-A307-D20C47324D10

Executive Summary

The Karn Unit 4 Induced Draft (ID) Fan Inlet Damper Replacement project is critical to ensuring reliable and efficient operation of the unit. The current ID fan inlet dampers, which are essential for controlling the boiler draft, are aging and have caused multiple forced outages and significant capacity de-rates over the past five years. These failures have resulted in high operational costs, inefficiencies, and risks of continued disruptions during peak operational periods. Replacing the dampers is a proactive investment that will eliminate these risks and provide long-term operational stability.

The project's estimated total cost is **$3 million**, to be spent in 2025, including **$2.3 million** for labor and **$700,000** for materials. This one-time investment will deliver substantial financial and operational benefits, positioning the unit for reliable operation through the remainder of the plant service life.

Key benefits of this project include:

- **Avoidance of Capacity Losses**: Without replacement, Karn Unit 4 would continue to experience forced outages and de-rates, resulting in cumulative capacity losses. Based on two failures per year, these losses are projected to reach approximately **$4.55 million** by 2031. Replacing the dampers will prevent these escalating penalties, providing significant cost savings over the long term.
- **Avoidance of Recurring O&M Costs**: The current reactive repair strategy has led to annual maintenance costs exceeding **$50,000**. With new dampers in place, these recurring costs will be eliminated, further improving the plant's financial performance.
- **Fuel Savings from Lower AGC Load**: Replacing the dampers is expected to lower the minimum load limits by **10 MW**, allowing the unit to operate more efficiently. This reduction in the load floor will result in additional fuel savings, further contributing to the overall cost-effectiveness of the project.
- **Improved Operational Flexibility and Reliability**: The replacement will restore full control over boiler draft, reducing the risk of trips and improving the plant's ability to operate flexibly during periods of fluctuating demand. This is particularly important during peak summer seasons when the grid is in critical need of generation.

In conclusion, while the initial capital investment is significant, the replacement of the Karn Unit 4 ID fan inlet dampers will eliminate ongoing capacity losses, reduce operational costs, and deliver substantial fuel savings. This project is essential for maintaining the unit's long-term reliability and maximizing its operational and financial performance through 2031.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$3,000,000

Proposed Start Implementation Year and project span

Implementation scheduled for Fall of 2025.

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Problem Description

The Karn Unit 4 Induced Draft (ID) fan inlet dampers play a crucial role in regulating the fan load and maintaining a negative draft in the boiler, which is essential for safe and reliable operation. Over the last five years, the dampers have experienced multiple failures, leading to forced outages and significant de-rates, indicating the urgent need for replacement.

Key points regarding the failure history:

- **Frequent Repairs**: Repairs have been needed during both the **spring and fall outages** for the last five years, with some repairs being more extensive than others. The consistent repair needs point to the deteriorating condition of the dampers.
- **De-rates and Outages**: When the dampers fail, the unit has experienced de-rates as high as 300 MW, with repairs typically taking about a week.
- **Forced Outages**: Even the easiest repairs, such as linkage repairs, have resulted in forced outages. Recently, a forced outage was taken to repair an ID fan damper linkage, requiring a **two-day outage**. More complex repairs, such as internal damper work, take significantly longer and are more costly.
- **Internal Repairs Require Scaffolding**: All internal repairs to the ID fan inlet dampers require scaffolding, adding significant costs. Vendor quotes for recent repairs include:
  - **$31,000 for scaffolding** in a fall 2023 repair quote.
  - **$76,000 estimate** for internal damper work in May 2024, with **$26,000 allocated for scaffolding**.

Given this failure history, we have conservatively assumed **two failures per year**—one in the spring and one in the fall. This assumption is based on the consistent pattern of repairs and forced outages over the past five years. Even minor repairs have caused forced outages, impacting the unit's reliability and availability.

Financial Losses

We have used a conservative estimate of **$50,000 per repair** for both internal and external damper repairs. This estimate is based on actual repair costs from recent vendor quotes and repair history listed in this section. The costs of addressing internal and external failures over the past five years highlight the growing financial burden of maintaining these aging dampers.

Considering the repeated need for internal and external repairs, **$50,000 per repair** is a **conservative assumption**. The actual costs of maintaining the aging dampers will likely increase over time as the system continues to deteriorate. By assuming two failures per year, we are accounting for the true financial burden of these recurring issues, though actual costs may exceed this estimate.

The current condition of the dampers is unsustainable. These original components, exposed to harsh operating environments, are no longer reliable. Failure is imminent, and replacement is necessary to restore proper operation and eliminate ongoing operational and financial challenges.

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Alternative Solutions/Alternatives Considered

1. Do Nothing – Cost: $4,549,664 in capacity losses plus $50,000 in repair costs.

Opting to "do nothing" and forgo the replacement of the Karn Unit 4 ID fan inlet dampers would mean continuing the current strategy of performing reactive repairs when a damper fails. This approach, which has been in place for several years, relies on the use of O&M funds to repair the dampers after each failure, while also incurring de-rates and forced outages during peak demand seasons.

Key impacts of the “Do Nothing” option include:

- **Frequent Forced Outages and De-Rates**: Karn Unit 4 has tripped multiple times over the past five years due to positive pressure in the boiler or an inability to control the draft caused by failing dampers. Each of these failures results in a 300 MW de-rate, which can typically take about a week, depending on whether the issue is internal or external. Each one-week derate is expected to cost $81,244 per year in potential capacity losses and will carry an additional penalty of $81,244 for the next three years. Table 1 below summarizes the capacity loss impact of a single failure.

Metric	Value
GVTC (Unit Capacity)	614.7 MW
Seasonal Accredited Capacity (ZRCs)	273.1 ZRCs
CONE Value (75% of $127,135)	$95,351
De-Rate Impact (300 MW for 1 week)	$81,244 per year
Impact Over 3 Years (MISO rules)	$243,731 total

Table 1. Capacity losses summary for a 300MW one-week derate.

Continuing this reactive approach would also result in ongoing capacity losses. Based on past failure history of two failures per year over the last five years, it is assumed with high certainty that there will be at least two failures per year with the current equipment condition. With two anticipated failures per year, this leads to an annual impact of **$162,488**. As per MISO rules, each year’s failures will affect the following three years, compounding the losses over time. Table 2 below shows the summary of the cumulative financial losses from 2025 through 2031:

Year	Annual Capacity Loss from Current Year Failures	Ongoing Loss from Previous Failures	Total Loss for the Year
2025	$162,488	$0	$162,488
2026	$162,488	$162,488	$324,976
2027	$162,488	$324,976	$487,464
2028	$162,488	$487,464	$649,952
2029	$162,488	$649,952	$812,440
2030	$162,488	$812,440	$974,928
2031	$162,488	$974,928	$1,137,416

Table 2. cumulative capacity losses from 2025 to 2031

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Total Cumulative Loss from 2025 to 2031: $4,549,664

By continuing the current strategy with two failures per year, the total cumulative capacity loss would reach approximately **$4.55 million** by 2031. This far exceeds the one-time **$3 million** investment required for a complete replacement, making the replacement option the more cost-effective long-term solution.

- **High Operational and Maintenance Costs**: The reactive repair strategy has led to annual O&M costs exceeding $50,000 for damper repairs. Replacement parts such as damper blades have a lead time of 2-3 days and repairs take up to a week. This approach has proven costly, as it does not address the underlying problem of aging dampers that operate in a harsh environment.
- **Reduced Operational Efficiency**: Due to the damper issues, Karn Unit 4 operates with a higher minimum AGC load of 70 MW—10 MW higher than Karn Unit 3. This increases fuel costs, reduces operational flexibility, accelerates wear and tear on the equipment, and limits the unit's ability to support grid stability, especially during peak demand periods.

2. Complete Replacement of ID Fan Inlet for Karn 4. Cost - $3,000,000

Selecting the option to completely replace the ID fan inlet dampers for Karn Unit 4 would provide a long-term solution to the current operational issues, ensuring reliable control of the boiler draft. The total cost of the replacement is estimated at **$3 million**, to be spent in 2025, with **$2.3 million** allocated for labor and **$700,000** for materials. This investment would provide reliable operation for the remainder of the plant's operational life.

Key Benefits:

- **Reliable Operation**: The new dampers would ensure effective and precise control of the boiler draft, eliminating the risks of positive pressure in the boiler that have caused multiple unit trips and de-rates in recent years. With new dampers, the plant can operate more efficiently, with fewer forced outages and a reduction in unscheduled maintenance.
- **Long-Term Cost Savings**: Although the initial capital investment of **$3 million** is significant, it would eliminate the recurring costs of reactive repairs, which have exceeded **$50,000 annually**. By addressing the root cause of the failures, the complete replacement would prevent the frequent outages and capacity losses that occur under the "do nothing" approach.

  In total, by 2031, the cumulative loss would reach **$4.55 million** due to capacity losses alone, not counting the ongoing repair costs. This figure starkly contrasts with the initial $3 million investment, which would prevent these escalating losses, making the replacement option more financially prudent over the long term.

- **Operational Efficiency**: Replacing the dampers will restore the unit's ability to operate with a lower AGC load, improving the plant's operational flexibility and reducing fuel consumption. This will also reduce wear and tear on the unit, leading to lower maintenance costs over time. By addressing the issues of higher AGC load (currently 70

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MW, 10 MW higher than Karn Unit 3), the plant will be better positioned to support grid stability, especially during periods of fluctuating demand or increased reliance on renewable energy sources.

- **Enhanced Grid Support**: With reliable dampers, Karn Unit 4 can better support the grid, especially during peak summer seasons, when the plant plays a critical role in meeting high electricity demand. By eliminating the risk of de-rates and ensuring the unit can operate at full capacity, Consumers Energy can maximize the value of the unit during critical times of grid need.

Conclusion:

Replacing the ID fan inlet dampers is the most financially and operationally attractive option. It eliminates the recurring issues of forced outages, de-rates, and costly repairs, while ensuring Karn Unit 4 operates efficiently and reliably. This investment not only addresses the current risks but also positions the plant to deliver reliable power generation, especially during peak periods.

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Funding and Timing

- Funding has been previously committed for this project: none
- An outage is required for this project.
- Desired implementation year: 2025

System Engineer

- System Engineer: Craig Jeske

Conceptual Estimate

Year	*Loaded Cost*	*Description*
2025	**$3,000,000**	Engineering and install.

Total Cost: $3,000,000

Asset Strategy Approval Comments

The Asset Strategy Group strongly recommends approval based on cost-benefit analysis.

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Approvals

Title	Approver Name	Date
Generation Planning Manager	Signed by: Cornelius Thompson Jr F6F211CF147C460...	10/24/2024 | 4:41 PM EDT
Director of Generation Asset Strategy	DocuSigned by: Scott Hugo 31EC7A87F8F34C6...	10/24/2024 | 12:52 PM EDT
Exec Director of Electric Supply Engineering	Signed by: Richard T. Blumenstock C3E2F0B9920949B...	/2024 | 11:36 AM EDT
VP of Electric Supply	Signed by: Srikanth Maddipati 67DA622787D2488...	12/11/2024 | 9:49 PM EST

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Concept Approval

Zeeland Phase 2 Gas Turbine upgrades.

Date: 5/23/2025

Prepared by: Paul Ohep



Figure 1. Zeeland Generating station.

Executive Summary

The Zeeland Generating Station, a critical asset in Consumers Energy's portfolio, is set to undergo significant upgrades to enhance its performance and reliability. This project focuses on the Zeeland Phase 2 gas turbines, leveraging advanced technologies to support the transition to a more renewable energy portfolio. Importantly, this upgrade is identical in scope and design to the improvements implemented on Zeeland Units 1A and 1B, which were approved as part of the 2024 electric rate case.

Problem Description

The Zeeland Generating Station operates with a combination of four gas turbines and one steam turbine in a combined cycle configuration. These units are maintained under a Long-Term Service Agreement (LTSA) with GE, ensuring their periodic overhaul. In 2028, the Zeeland Phase 2 site is scheduled for Major Inspection outages, presenting an opportunity to implement substantial improvements. The primary goal is to replace the "hot" or combustion components of the turbines, which degrade over their 32,000-hour design lifespan.

Proposed Solution

The project proposes the implementation of two advanced technologies:

- **Advanced Gas Path (AGP)**: This technology aims to elevate the output and efficiency of the turbines by replacing existing parts with high-performance components, resulting in notable improvements in output and heat rate efficiency. Specifically, the AGP upgrade is expected to improve output by 51 MW for the entire Phase 2 plant at full/base load and enhance heat rate efficiency by 2.5%.
- **Axial Fuel Staging (AFS)**: This upgrade enhances the turbines' output turndown capability, allowing for lower load operations while maintaining emissions compliance. This flexibility is crucial as Consumers Energy moves towards a diverse energy portfolio reliant on renewable sources.

Alternative Solutions Considered

- **Do Nothing**: Maintaining the current unit configuration without upgrades would result in forfeited savings of $40.8M and a decrease in market competitiveness and operational flexibility.
- **Install AGP Only**: This option involves an initial capital investment of $51.0M, with projected incremental revenue of $121.8M through 2040 and a favorable NPV gain of $45.5M.
- **Install AFS Only**: This option was not pursued further due to significant financial hurdles and the lack of additional capacity revenue.
- **Install both AGP and AFS (recommended)**: The recommended option is to install both AGP and AFS technologies (same scope as Phase 1 project), with an initial investment cost of $55.7M. This comprehensive upgrade is expected to provide superior flexibility, emissions compliance, future market competitiveness, and standardization benefits. The potential NPV savings are estimated at $40.8M from 2025 through 2040.

- Despite the AGP-only option providing $4.7 million additional NPV savings compared to the combined AGP + AFS option, the latter remains favored due to its enhanced flexibility, compliance with emissions standards, anticipated future market competitiveness, and standardization advantages. These factors will be discussed comprehensively in the subsequent sections of the concept approval.

Funding and Timing

- **No prior funding committed**.
- **Scheduled outage required**.
- **Desired implementation year**: First year spend in 2025, installation in 2028.
- **Impact of delay**: Delaying implementation beyond 2028 poses significant risks and missed opportunities, potentially delaying benefits realization until the next major outage overhaul opportunity which is currently scheduled for 2034.

Conclusion

The AGP-AFS upgrade is a forward-thinking approach that promises significant performance enhancements, substantial long-term financial benefits, and improved adaptability to support Consumers Energy's energy portfolio. This investment is justified by the considerable potential savings and the strategic alignment with the transition to renewable energy sources.

Financial Summary

Estimated investment: **$44.9M**

Proposed Start Implementation Year and duration.

First year spend 2025, installation year 2028.

Problem Description

The Zeeland Generating Station, a key asset in Consumers Energy's portfolio, operates using a combination of four gas turbines and one steam turbine, configured as a combined cycle plant. These critical units are maintained under a Long-Term Service Agreement (LTSA) with GE, which ensures their periodic overhaul and upkeep, restoring them to near-original condition. A crucial aspect of these overhauls, conducted during major outages managed by GE, involves replacing the "hot" or combustion components of the turbines. These components typically degrade over their 32,000-hour design lifespan.

In 2028, the Zeeland Phase 2 site is scheduled for Major Inspection outages, presenting an opportune moment to undertake substantial improvements in both Phase 2 gas turbines. This project is centered around the implementation of upgraded replacement parts that significantly enhance performance and reliability.

Advanced Gas Path (AGP): This technology aims to elevate the output and efficiency of the turbines. AGP involves replacing existing turbine and combustion parts with high-performance, technologically advanced parts. The enhancement is expected to deliver notable improvements in output and heat rate efficiency, while maintaining the same level of reliability.

Axial Fuel Staging (AFS): In conjunction with AGP, AFS is another important upgrade. It enhances the turbines' output turndown capability, crucial for flexible operation. This is achieved by replacing and adding advanced combustion hardware, allowing for lower load operations while still adhering to emissions compliance. Such advancements are increasingly vital as Consumers Energy moves towards a diverse energy portfolio heavily reliant on renewable sources. The AFS technology is instrumental in ensuring that the Zeeland Phase 2 combined cycle gas turbines maintain operational flexibility to support this transition, accommodating the variability inherent in renewable energy sources.

Alternative Solutions/Alternatives Considered

1. Do Nothing – Cost: $40.8M (unrealized savings)

This alternative involves maintaining the current status quo at Zeeland Generating Station, where there is no immediate requirement to replace the turbine and combustion parts with higher performing components.

Cost Implication

- **Cost:** $40.8M (Forfeited Savings) + Forfeited AFS benefits
- **Impact:** Choosing this option results in forgoing the potential savings and benefits that could be achieved through Alternatives #2 and #3.

Detailed Analysis

- **Forfeited Potential Savings:** If neither Alternative #2 (AGP installation) nor Alternative #4 (AGP & AFS installation) is selected, Zeeland Phase 2 stands to lose potential savings $40.8M with AGP & AFS over the period from 2025 to 2040. These savings are detailed in the AGP & AFS alternative description.
- **Market Competitiveness and Flexibility:** Without implementing either of these advanced technologies, there is a significant risk that Zeeland Phase 2 will become less competitive and flexible in the rapidly evolving electrical generation market. The introduction of renewable energy sources demands greater flexibility from conventional generation assets, which this option fails to address.
- **Opportunity Cost:** The cost of this "Do Nothing" option is effectively the lost opportunity to save and improve. While not investing in upgrades might seem to save money in the short term, it equates to a considerable loss in terms of unrealized savings and market adaptability.

Opting to maintain the current setup without upgrades translates into a significant loss of potential savings and a decrease in market competitiveness and operational flexibility. This option, while seemingly cost saving, could lead to substantial opportunity costs and a failure to adapt to the changing dynamics of the energy market.

2. Install AGP only- Cost: initial capital investment of $51,011,000

This alternative entails the installation of an Advanced Gas Path (AGP) in Zeeland Phase 2's gas turbines, a significant upgrade to enhance performance and efficiency.

Financial Overview:

- **Cost:** Total customer cost of $51M over the life of the upgrade in today's dollars based on a fixed charge rate of 13.59% (Based on internal estimates incorporating contractor quotes and overhead loadings).
- **Revenue:**
  - The projected incremental revenue for this project is estimated to be $121.8M through 2040.
  - The projected incremental capacity revenue is projected to be $34.8M through 2040.
- **Impact:** The AGP only option will provide a favorable NPV gain of $45,524,000 through 2040. This is based on an Aurora internal economic model performed in February of 2025.

Table 1 below summarizes the incremental revenues and costs for the AGP only option.

Net Present Value Results	AGP Only case with 588 MW Capacity Revenue Cap
Current Nameplate Capacity (MW)	553
Upgraded Capacity (MW)	604
NPV, Incremental Energy Revenue AGP only (K$)	($121,803)
NPV, Incremental Capacity AGP only (K$)	($34,846)
NPV, Incremental Operating Costs AGP only (K$)	$60,114
NPV, Investment AGP only (K$)	$51,011
NPV, Total Value of Phase 2 Upgrade (K$)	**($45,524)**

Table 1. Revenue and costs table for AGP only option

Economics modeling assumptions:

The economic model for this option is based on the following AGP assumed features:

- Capacity value is assumed at 75% of the cost of new entry.
- Capacity accreditation is estimated at 90% for all seasons.

Output Improvement

- **Improvement:** +51MW for the entire Phase 2 at Full/Base Load, based on GE's quotes.

Heat Rate Improvement

- **Improvement:** 2.5% Efficiency Improvement across Load Range.

Components and Work Scope:

- AGP Parts: Includes all necessary AGP components, new Gas Control Valves (GCVs), and Stop-Ratio Valve (SRV). The cost is escalated from the 2025 base by 3% per year.
- Comprehensive Upgrade: The upgrade involves replacing hot parts with AGP components, transitioning from DLN2.6 combustors to DLN2.6+ to enable AGP performance enhancements, increasing the shaft torque limit rating, revising control curves, and adjusting control constants.
- Turbine Model Change: These modifications will upgrade the turbine model from 7FA.03 to 7FA.04.
- GCVs/SRV Replacement: To realize the full potential of the AGP/DLN2.6+ work, replacing the GCVs/SRV is crucial. This will also address the gas supply pressure limitations in the upper output range by reducing approximately 25 psi of pressure drop across these components.

Financial Outlook:

The AGP-only upgrade, with a comprehensive scope of work to elevate turbine efficiency and performance, represents a strategic investment towards modernizing the Phase 2 turbine. The project is anticipated to result in significant Net Present Value (NPV) savings of $45.5 million over a fifteen-year period, to 2040. This includes considerations for incremental energy and capacity revenue, along with a detailed analysis of operating costs and investment requirements.

3. Install Advance Fuel Staging only

The AFS-only option explores the introduction of Axial Fuel Staging technology to the turbines at Zeeland Generating Station, focusing solely on this upgrade without the inclusion of Advanced Gas Path (AGP) components. The AFS technology is designed to enhance combustion efficiency and reduce emissions, aligning with operational improvements and environmental compliance objectives.

Although the AFS-only upgrade offers notable operational benefits, such as enhanced emissions control, it encounters significant financial hurdles. These challenges stem from a lack of additional capacity revenue and the inability of increased energy revenue alone to cover the substantial upfront investment and ongoing operational costs. Crucially, the AFS-only strategy misses out on the considerable operational improvements associated with AGP enhancements, including a capacity boost of 51MW (total for entire Phase 2) and a heat rate improvement of 2.5%.

Based on prior experience with modeling AFS only upgrade with Phase 1 and vendor recommendations, it was decided not to look further into this option as it is not typically installed on its own and will most certainly result in losses over time (as modeled for phase 1 upgrade).

4. Install AGP and AFS – initial investment cost - $55.7M – Recommended option

This alternative proposes a comprehensive upgrade to the Zeeland Phase 2 gas turbines by installing both Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies.

Financial Overview:

- **Cost:** Long term financial budget of $44.9M. Total customer cost of $55,669,000 over the life of the upgrade in today's dollars based on a fixed charge rate of 13.59% (Based on internal estimates incorporating contractor quotes and overhead loadings).
- **Impact:** Potential Net Present Value savings of an estimated $40.793M from 2025 through 2040 from the upgrade. This is based on an Aurora internal economic model performed in February of 2025.

Components and Work Scope:

- **AGP Parts and Work:** AGP components include new Gas Control Valves (GCVs), Stop-Ratio Valve (SRV), and related replacement work.
- **Comprehensive Turbine Upgrade:** Incorporates the scope of Alternative #2 (AGP installation) while adding AFS components. This includes replacing hot parts with AGP components, upgrading combustors to DLN2.6+, and making necessary revisions to control curves and constants.
- **Turbine Model Change:** These upgrades will transform the turbine model from 7FA.03 to 7FA.04.
- **Enhanced Gas Supply Efficiency:** Replacement of GCVs/SRV will mitigate gas supply pressure limitations in high output ranges by reducing pressure drop.

AGP + AFS upgrade Economic benefits breakdown and assumptions:

Table 3 below shows a summary of the NPV incremental costs and revenues for this option.

Net Present Value Results	AGP+AFS full upgrade
Current Nameplate Capacity (MW)	553
Upgraded Capacity (MW)	604
NPV, Incremental Energy Revenue Full upgrade (K$)	($120,623)
NPV, Incremental Capacity Full upgrade (K$)	($34,846)
NPV, Incremental Operating Costs Full upgrade (K$)	$59,007
NPV, Investment Full upgrade (K$)	$55,669
NPV, Total Value of Phase 2 Full Upgrade (K$)	**($40,793)**

Table 3. Revenue and costs table for AGP and AFS option

Economics modeling assumptions:

The economic model for this option is based on the following AGP assumed features:

- Capacity value is assumed at 75% of the cost of new entry.
- Capacity accreditation is estimated at 90% for all seasons.

Differences between AGP only and AFG+AFS upgrades:

Tables 2 and 3 above show that, based solely on quantitative modeling, the AGP-only upgrade appears to be more valuable by $5M over the next 15 years compared to the full AGP+AFS upgrade. The reason for this is that our model doesn't assign an appreciable impact from lowering the minimum load (when adding AFS) as units are typically chosen based on mid- and max-load capabilities rather than minimum load. Dispatch decisions are made when there is an expected increase in demand.

However, when considering both quantitative and qualitative impacts, the full AGP+AFS upgrade offers significantly more value than the additional ~$4.7M provided by the AGP-only option.

Below is a breakdown of the full benefits of AGP+AFS upgrade over AGP-only option:

1. Flexibility
    - For a Renewable Grid – The flexibility that will be offered and needed in the future is difficult to model, and we believe it will be very valuable to support a grid that requires baseload generation (like Zeeland Phase 2) to respond to the flexibility required by Renewable Generation.
    - Leading to Equipment Reliability – The cost savings in equipment reliability due to cycling could be substantial in the future, with an additional investment of $4M now potentially reducing the number of future shut-downs. This reduction would be achieved by having a lower minimum load capability. The load reduction from this upgrade may become more frequent in the afternoon as more solar generation is added, necessitating two major load-following events. A lower minimum load capability could determine whether the equipment shuts down for a few hours or remains at minimum load (spinning reserve).

2. Emissions Compliance – AFS will be valuable operationally and legally / for regulatory factors because during start-up, AFS will help Zeeland Phase 2 get into emissions compliance mode much earlier into the start-up process. This is important, because the Zeeland Phase 2 air permit will most likely change as it is changing for Phase 1 (due to the AGP part of the upgrades) to include much more strict emissions compliance standards during start-ups (potentially lower emissions rates but also less exceptions for start-up emissions).

3. Future Market Competitiveness – The growth rate in gas plants adding the AFS technology (and newer plants being built with the technology) is trending toward exponential. By the early 2020s, GE had only 4-5 examples of the technology being used, but 2024 saw two more installations, with 2025/2026 seeing numerous more installations according to GE as stated at the May 2024 7F Users Conference. Utilities are starting to see the major value of the flexibility offered by AFS, and as more plants

retrofit or are built new with the technology, Zeeland Phase 2's flexibility value will remain competitive with the market supporting a more Renewable grid.

4. Standardization and Capital Spares Reduction – The Full Upgrade case would standardize the parts between our Phase 1 and Phase 2 units as they would then be the exact same turbines. That benefit is somewhat difficult to quantify value-wise, but it goes a long way to benefiting reliability, troubleshooting when issues arise, and having spare parts.
5. Installation timing efficiency - Installing the AFS upgrades simultaneously with the AGP (and DLN2.6+) is recommended due to the significant amount of additional fuel routing required for the AFS upgrade.

Overall, the Full Upgrade (AGP & AFS) provides superior flexibility for supporting a grid that is going quickly to Renewables for ~$5M less value out of around $40M savings to our customers over the next 15 years.

Scope of Work

Scope of Work Activities for Erickson's and GE's Major Inspection at Zeeland Phase 2:

1. Erickson's Responsibilities:

- Provide cranes and lifting services as part of the already scheduled and budgeted GE Long-Term Service Agreement (LTSA) Major Inspection work.

2. GE Parts/Software Scope of Supply:

Advanced Gas Path (AGP) Components:

- AGP Stage 1 Nozzle Kit and Support Ring.
- AGP Stage 2 and 3 Nozzle Kits.
- AGP Stage 1, 2, and 3 Bucket Kits.
- AGP Stage 1, 2, and 3 Shroud Kits.
- Cooling and sealing air orifice modification.
- Provision of installation and modification documents.
- OpFlex Enhanced Transient Stability Model-Based Controls platform.
- Firing temperature increase and revised Model-Based Control (MBC) software changes.
- 7FA.04 length 1AO, 2FO, 2AO wheelspace thermocouples.

DLN 2.6+ Components:

- ML A033 Major Disassembly Tool Kit.
- ML 0513 Gas-Only Fuel Nozzle Assembly.
- ML 0572 Fuel Gas Emergency Stop Valve.
- ML 0701 Combustion Chamber Arrangement.
- ML 0702 Transition Piece Assembly.

- ML 0703 Combustion Liner Arrangement.
- ML 0717 Transition Piece Arrangement.
- ML 0719 Aft Combustion Case Arrangement.
- ML 0726 Combustion Tuning Piping.
- ML 1214 Spark Plug Assembly.

Gas Control Valves (GCVs) / Stop Ratio Valve (SRV):

- High Recovery Gas Control Valves (GCVs).
- Stop Ratio Valve (SRV).
- Supporting piping, conduit, and hydraulic components.
- Modifications to Gas Turbine Controls.

Axial Fuel Staging (AFS) Components:

- AFS injectors and sealing.
- Fuel delivery tubing and valving.
- Additional 5th fuel circuit and manifold for AFS.
- Manway covers.

3. GE Work Scope:

- Removal of old turbine parts.
- Installation of new AGP and AFS components.
- Modifications to existing parts as required.
- Revision of control curves and constants to integrate the new upgrades.

This comprehensive scope of work outlines the key activities and components involved in the upgrade project for Zeeland Phase 2, ensuring the successful integration of Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies.

Funding and Timing

- No funding has been previously committed for this project.
- A Scheduled outage is required for this project.
- Desired implementation year: First year spend 2025, installation year 2028
- Impact if the recommended implementation year is changed:
    - Delaying the implementation of Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies at Zeeland Phase 2 to a year beyond the recommended 2028 poses significant risks and missed opportunities. Postponing these upgrades until the next outage of opportunity, potentially 5-6 years later during the next Hot Gas Path Inspection, would result in a considerable delay in realizing the benefits for Consumers Energy's customers.
- System Engineer: Tim D. Boerema

Conceptual Estimate

Year	Loaded Cost	Description
2025	**$60,000**	Initial engineering work
2026	**$7,969,033**	25% Payment for Lump Sum
2027	**$24,834,311**	AGP/AFS Payment for Design and engineering
2028	**$12,036,656**	AGP/AFS 75% payment, installation, and closeout

Total Cost: $44,900,000

Asset Strategy Approval Comments

The Asset Strategy Group recommends approval. The AGP-AFS upgrade is a forward-thinking approach that not only promises significant performance enhancements but also substantial long-term financial benefits and improved adaptability of the turbines to support Consumers Energy's energy portfolio. This investment is justified by the considerable potential savings.

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002026	**2026**	**3**	**Literal**

Investment Name	Scenario
(11712) ZGS - Phase II Turbine Replacements - Owner obligations	**Draft**

Value Function	**Consumers Energy Value Function**

The Zeeland Generating Station is a gas-powered combustion turbine site consisting of four gas turbines and one steam turbine. These turbines are covered by a Long Term Service Agreement (LTSA) with GE to provide overhauls and upkeep on the units, periodically restoring them to like-new condition. The turbine rotors have a design life of 144,000 hours, at which time the rotors are required to be replaced. The rotors will have approximately 130,000 hours in 2028, and going another 32,000-hour maintenance cycle would violate the 144,000-hour Rotor Replacement requirement.

The ideal time to do the Rotor Replacement is during a Major Inspection (because the rotor is pulled for inspection), which only occurs every other 32,000-hour maintenance cycle. The first 32,000-hour maintenance cycle leads to a Hot Gas Path Inspection (HGPI, the rotor is not pulled for this work), the second 32,000-hour maintenance cycle leads to a Major Inspection (Major), and then two more 32,000-hour cycles are repeated leading to the final Major when the rotor is required to be replaced. ThetwogasturbinesatZeelandPhase2havetheirsecondMajoroutagesin2028. Therefore, the Rotor Replacement should occur during the 2028 Major. This project is to replace the turbine rotors in both Phase2 gas turbines in conjunction with the 2028 Major.

Investment Type	Generation	Planning Portfolio	Zeeland
Facility	Zeeland / Zeeland		
Executive Summary	The Zeeland Generating Station (ZGS) is a gas-powered combustion turbine site comprising four gas turbines and one steam turbine. These turbines are maintained under a Long-Term Service Agreement (LTSA) with GE, which includes periodic overhauls to restore them to like-new condition. The turbine rotors have a design life of 144,000 hours, necessitating their replacement upon reaching this threshold. By 2028, the rotors will have approximately 130,000 hours, making it imperative to replace them during the 2028 Major Inspection to avoid violating the LTSA. Draft Forecast$36,440,404 Between Jan 2026 and Dec 2028 Scope of Work: The project involves replacing the turbine rotors in both Phase II gas turbines during the 2028 Major Inspection. This includes: Incorporate various enhancements to the rotor and compressor components to improve damage tolerance, reduce wear, and maintain and improve reliability. Objectives and Benefits: •Mitigate the risk of major extended plant shutdowns. •Enable continued operation beyond 2028. •Optimize outage timing to maximize unit availability. •Ensure compliance with LTSA contract requirements. •Ensure plant reliability goals are achieved until at least 2045. •Reduce inspection requirements and increased reliability and availability. •Improved damage tolerance and robustness of the rotor. Model Assumptions: •The rotor replacement is required to continue operations beyond 144,000 hours. •Failure to replace the rotors during the 2028 Major Outage would result in Phase II ceasing operation by 2029, leading to significant financial losses. 100% chance of Phase 2 becoming inoperable in 2029 if this work is not performed, leading to forfeiting $80M of savings when comparing purchasing Zeeland Phase 2's generation on the MISO market.		
Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	No
	Outage Type	Site
	Scope	Erickson's will provide cranes and lifting services as part of the GE LTSA Major Inspection work, which has already been scheduled and budgeted. GE Parts/Software Scope of Supply: Dovetail slots of forward stub shaft (FSS): Incorporate shot peening and undercut feature. Dovetail slots of wheel 1 (CW1): Incorporate shot peening. Enhanced R0 thru R8 blades: Enhanced R0 blades: Blades with a completely new airfoil design improved with: Airfoil shot peening: The full airfoil surface is mechanically peened to achieve improved tolerance to erosion, corrosion, and foreign object damage. Laser shock peening: The leading-edge root is treated with laser shock peening to provide high resistance to erosion, corrosion, and foreign object damage. Dovetail undercut: Performed on both sides of the dovetail to minimize fretting wear by mitigating stress at the edge of contact and moving the fretting area away from high stresses. Graphite coating on dovetail: Applied on both sides of the dovetail to reduce fretting wear. Squealer tip: Intended to increase rub tolerance. Enhanced R1 thru R3 blades: Same airfoil design as the original, improved with: Full airfoil shot peening. Dovetail undercut. Graphite coating on dovetail. Squealer tip (ONLY R1s). Enhanced R4 and R5 blades: Same airfoil design as the original, improved with: Full airfoil shot peening. Dovetail undercut. Enhanced R6 thru R8 blades: Same airfoil design as the original, improved with full airfoil shot peening. R12 thru R17 wheels: Incorporate round slot bottom (RSB) dovetail design, greatly reducing stress on the dovetail slot and excluding the Rotor from TIL 1972. Optimized clocking on Stages 14 thru 16 blade & wheel assemblies: The blade pattern for Stages R14 thru R16 improves stator reliability by eliminating the S14 thru S16 vane rocking phenomena. Current production Gen-V turbine Rotor spool: Incorporates the following features: Optimized air-cooling slot design on Stage 1 and 2 wheels, reducing stress cracking in the corners of the cooling slots.
	Objectives	Mitigate the risk of major extended plant shutdown. Optimize outage timing to maximize availability of the unit Ensure plant reliability goals are achieved until at least 2045.

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002026	**2026**	**3**	**Literal**

Investment Name	Scenario
(11712) ZGS - Phase II Turbine Replacements - Owner obligations	**Draft**

Value Function	**Consumers Energy Value Function**

	Planner Recommended Alternative	This scope replaces the existing rotor with a new one, providing another 144,000 hours of operation, which would enable operation until the next rotor replacement around the year 2045. Also included in this scope are new compressor stator vanes due to the compressor being 28 years old; the best way to restore the compressor to like-new condition is to replace the stationary parts when the blades are already being replaced. Lastly, the exhaust frame will be upgraded to a robust exhaust frame due to reliability issues over the years, and the rotor replacement is an appropriate time to replace the exhaust frame. For one year of operation (based on 2022 data), Zeeland Phase 2 saved Consumers Energy and customers approximately $80 million due to being less expensive than the system cost. Assuming Zeeland Phase 2 continues to be significantly valuable from 2028 through 2045, this yields significant forfeited savings that Zeeland Phase 2 could have contributed should the rotors not be replaced. Additionally, Zeeland Phase 2 has an electrical generation supply contract with Hemlock Semiconductor through 2040 that would be violated should the units become unavailable for anything but normal outage cycles. With the refurbished rotor's design life of 100,000 hours, the timing with the maintenance cycles would incur additional costs due to the 32,000-hour maintenance cycle leading to a HGPI outage at the rotor replacement requirement. As mentioned, the HGPI does not require the rotor to be pulled for inspection and parts replacement. Additionally, the total Major Outage duration for both gas turbines is approximately 55 days compared to HGPI's duration of 25 days. The rotor replacement not lining up with a Major leads to additional GE costs as the LTSA costs cover alternating between HGPIs and Majors for hours-based gas turbines like those at Zeeland Phase 2, where the rotor replacement essentially requires more work similar to a Major. Lastly, the cost of the rotor replacement to get to 2045 could not be avoided like in Alternative #2. Section 3's "Project Benefits/Objectives" box discusses the benefits in detail and the extra costs mentioned above, but a high-level summary is that potentially large savings could be forfeited compared to purchasing the generation that Zeeland Phase 2 generates on the MISO market from 2040 to 2045 if the rotor is not replaced in 2040 (disallowing continued operation). If it is determined Zeeland is needed to generate beyond 2040, the additional costs due to doing an off-cycle rotor replacement (leading to the aforementioned additional outage duration, PSCR, additional GE labor, and not avoiding this second rotor replacement) is approximately $43 million in 2028 dollars.
	Assumptions	The design life of the rotor requires it to be replaced at 144,000 hours to continue operation beyond this point. If the rotors are not replaced during the 2028 Major Outage, where they will have approximately 130,000 hours, the Major work would still be required to operate due to the 32,000-hour maintenance cycle requirement for hot parts replacement. The turbines could then run for another 14,000 hours (less than 2 years), at which point Phase 2 would have to cease operation due to meeting the design rotor life. 100% chance of Phase 2 becoming inoperable in 2029 if this work is not performed, leading to forfeiting $80M of savings when comparing purchasing Zeeland Phase 2's generation on the MISO market. Refurbishing rotor replacement alternative assumption: Assuming that Zeeland is required to generate from 2040 to 2045, using this option would require the company to spend an additional $43M in 2040 for a new rotor. Hard Benefits: Enables continued operation beyond 2028: Assumption that 2022 Zeeland Phase 2 generation savings compared to buying power from the market, worth approximately $80M, will continue to be true or greater in 2029. Avoids the below Alternative #3 additional costs totaling $43M in 2028 dollars if needed to operate to 2045, costing $17M more than the New Rotor cost in 2028: Outage Duration PSCR Costs Compared to Alternative #2's 25-day HGPI Outage required in 2040, this Rotor Replacement Outage would require 55 days (30 more days) 30 days x 24 hours x $30/MWh (assumed difference between LMPs vs. Site Cost) x 550 MW = $11.9M Additional GE Labor not Planned for under the LTSA = Assumed $3M Second Rotor Replacement = $28M Rotor Improvements: Improved damage tolerance/robustness, Reduced current inspection requirements (e.g., R0 erosion checks, Stator Vane inspections), Increased reliability and availability Improved end-of-life or extension-of-life flexibility decisions compared to Alternative #2 by the rotor design life going to Year 2045 for potential: Phasing out Zeeland Generation in the Consumers Energy portfolio, Converting the turbines to burn a different fuel, Implementation of carbon capture, Implementation of possible other technologies that have not yet emerged
Alternative Details	New rotor replacement	new rotor replacement
	Refurbished rotor replacement	Refurbished rotor replacement

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Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002026	**2026**	**3**	**Literal**

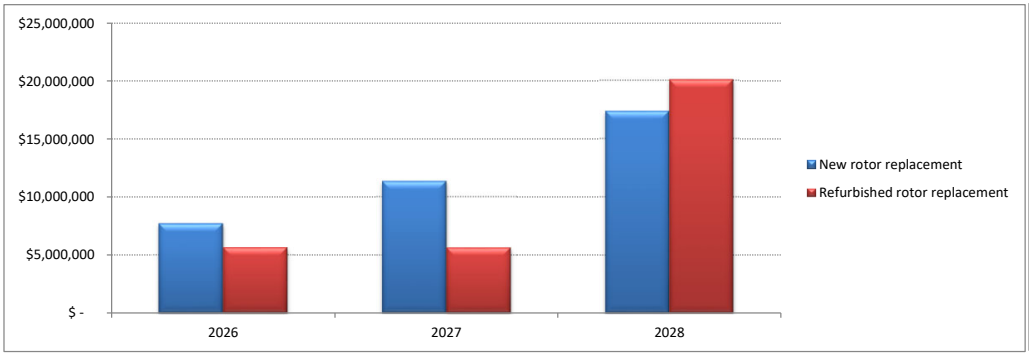
Investment Name	Scenario
(11712) ZGS - Phase II Turbine Replacements - Owner obligations	**Draft**

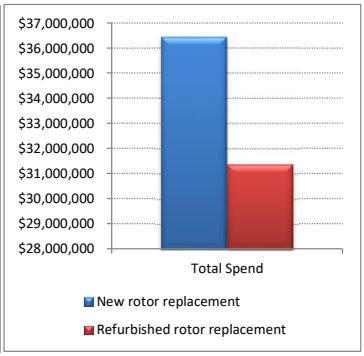
Value Function	**Consumers Energy Value Function**

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
New rotor replacement	Recommended	$ 36,440,404	1/1/2026
Refurbished rotor replacement	Candidate	$ 31,388,190	1/1/2026

Name	Status	2026	2027	2028
New rotor replacement	Recommended	$ 7,696,604	$ 11,344,861	$ 17,398,940
Refurbished rotor replacement	Candidate	$ 5,645,358	$ 5,645,358	$ 20,097,474





Forecasts - Draft (New rotor replacement)

Account Type	2026	2027	2028
Capital	$ 6,926,943	$ 10,210,375	$ 15,659,046
Cost Of Removal	$ 769,661	$ 1,134,486	$ 1,739,894
O&M	$ -	$ -	$ -

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002150	**2024**	**3**	**Literal**

Investment Name	Scenario
(12833) ZGS - Purchase of Site Spare GSU	**Draft**

Value Function	**Consumers Energy Value Function**

Zeeland Generating Station consists of four gas turbine powered plants and one steam turbine powered plant. The units transmit their power to the grid via Generator Step Up (GSU) transformers. If a GSU were to fail, then the associated turbine would not be able to transmit power and would not be able to generate energy and capacity market value for Consumers Energy and its customers. For Zeeland Phase 2 combined cycle plants, the combustion turbine requires the operation of the steam turbine, therefore the loss of the steam turbine GSU would effectively limit operation of two connected combustion turbine units. The lead time for a GSU is currently 100 weeks and spare units at other facilities typically do not exist. The site is currently projecting retirement in the 2050 timeframe. This project would purchase a spare GSU that is sized to be able to replace any of the existing transformers on site and develop redundancy for any minor power upgrades in the future

Investment Type	Generation	Planning Portfolio	Zeeland
Facility	Zeeland / Zeeland		

Executive Summary

The project involves the strategic purchase of a spare Generator Step Up (GSU) transformer for the Zeeland Generating Station. This spare GSU will be of sufficient size to replace any of the existing transformers on site, thereby eliminating the potential for a 24-month unplanned unit outage.

Objectives:

Mitigate lost generation risk of up to 540MW for a period of up to two years.
Ensure redundancy for any minor power upgrades in the future.
Mitigate the risk of prolonged outages due to GSU failure, thereby maintaining the operational integrity and reliability of the facility.
Recommended Alternative: Purchase a new spare GSU.

Draft Forecast: $4,930,694 (Between Jan 2024 and Dec 2026)

Model Assumptions:

A future failure of any of the five GSU transformers would remove the generating value of a unit, up to 280MW or more, and potentially remove it from being claimed as a resource to meet customer capacity needs. The duration of this outage would be expected to last up to 24 months.
Loss of the steam turbine GSU could result in a loss of both associated combustion turbines and a loss of up to 540MW for possibly two years.
Assume an average of 350MW for potential derate, with a 3% chance of realizing this risk.
Potential capacity losses in the event of a forced 350MW derate for two years have been calculated at $155,930,202, using a conservative calculator provided by the capacity forecast team. The CONE value used for this model is $130,930, with 75% of CONE used for the calculations as customary.

Conclusion: Purchasing a spare GSU transformer is essential to mitigate the risk of prolonged outages and ensure the reliable operation of the Zeeland Generating Station. This project aims to safeguard the facility's performance, prevent significant financial losses, and maintain the ability to meet customer capacity needs.

Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Other
	Scope	Strategically purchase a spare transformer of sufficient size to be able to replace any of the GSUs for the site. This would eliminate the potential of a 24-month unplanned unit outage. This size is currently estimated as a 280MVA unit.
	Objectives	This project offsets the lost generation risk of up to 540MW for a period of up to two years. Calculated IRR for this project was 118%. The site currently does not have any identified spare. Recent testing on 1A GSU revealed that the OEM does not recommend placing it back into service. A separate project is being developed to overhaul the existing GSU as well as install mobile GSUs in the interim.
	Planner Recommended Alternative	Purchase a spare GSU of sufficient size to replace any of the five existing transformers which will have sufficient capability for the four combustion turbine units. Material and overhead costs to place on site is approximately $5.5M, excluding installation. Due to the criticality of these transformers and the lost cost of generation, it would be most prudent to have a site spare unit available onsite to address this risk. Zeeland Combined Cycle had an NEV for 2020 of $17.8M, and is expected even higher for 2021. Other alternative: Purchase a spare for each common transformer on site for a total of two: one for the GSU's on the combustion turbines at 225MVA, and one for the steam turbine at 280MVA. Costs for the GSU's are approximately $5.5M each (excluding installation). Total cost $11M
	Assumptions	A future failure of any of the five GSU transformers would remove the generating value of a unit, up to 280MW or more, and potentially remove it from being claimed as a resource to meet customer capacity needs. The duration of this outage would be expected up to 24 months. Loss of the steam turbine GSU could result in a loss of both associated combustion turbines and a loss of up to 540 MW for possibly two years. Assume an average of 350MW for potential derate. 3% chance of realizing this risk. This model was used twice as copperleaf can only do one year at a time. Potential Capacity losses in the event of force 350MW derate for two years have been calculated at $155,930,202 . The calculations were made using a conservative calculator provided by the capacity forecast team. The CONE value used for this model is $130,930. 75% of CONE was used for the calculations as customary. Risk was calculated from 2025 until 2040. 3% chance of realizing this risk.
Alternative Details	Purchase new spare GSU	Purchase a spare GSU of sufficient size to replace any of the five existing transformers which will have sufficient capability for the four combustion turbine units. Material and overhead costs to place on site is approximately $5.5M, excluding installation.

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002150	2024	3	Literal

Investment Name: (12833) ZGS - Purchase of Site Spare GSU

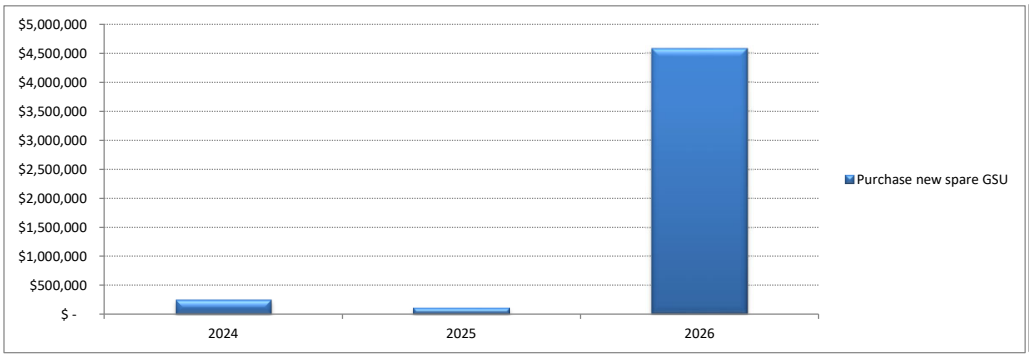
Scenario: Draft

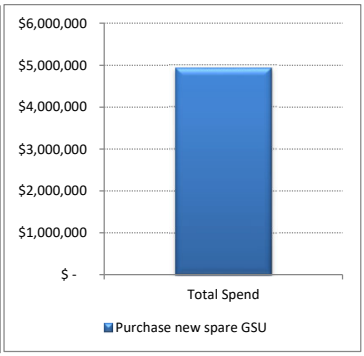
Value Function: Consumers Energy Value Function

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
Purchase new spare GSU	Recommended	$ 4,930,694	1/1/2024

Name	Status	2024	2025	2026
Purchase new spare GSU	Recommended	$ 242,857	$ 103,027	$ 4,584,810





Forecasts - Draft (Purchase new spare GSU)

Account Type	2024	2025	2026
Capital	$ 242,857	$ 103,027	$ 4,584,810
Cost Of Removal	$ -	$ -	$ -
O&M	$ -	$ -	$ -

EXHIBIT A-215 (MEW-22)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002987	**2028**	**1**	**Literal**

Investment Name	Scenario
ZGS - Main Steam & Hot Reheat Isolation Valves Replacement	**Draft**

Value Function	**Consumers Energy Value Function**

During the Fall 2023 Steam Turbine Minor Inspection outage at the Zeeland Generating Station (ZGS), a roughly 2.5" x 0.5" piece of stellite was found in the Main Steam (MS) strainer, which is just upstream of the MS Stop/Control Valves. The only potential areas from where this stellite could have originated is either the 2A or 2B MS Non-Return Valves (NRVs) or the 2A or 2B MS Stop Isolation Valves. The MS NRVs were already planned for replacement for other reliability reasons during the Fall 2024 Outage, which was complete. When the valves were removed from 2A and 2B, they were inspected to find no evidence of failure of the stellite seat and trim. That leaves the origination of the stellite piece found in the Fall 2023 Outage as coming from the 2A or 2B MS Stop Isolation Valves. Upon further investigation, numerous valve vendors confirmed that the industry has seen many failures of stellite delaminating from a valve body's parent metal to be sent to the downstream Stop/Control Valves. The strainer should catch these potential pieces, but in at least one case in the power industry, a piece wore a hole through the strainer, sending it to the Steam Turbine path causing significant Domestic Object Damage (DOD), requiring immediate shutdown and lengthy repairs for that unit.

Investment Type	Generation	Planning Portfolio	Zeeland
Facility	Zeeland / Zeeland		

Executive Summary	The ZGS - Main Steam & Hot Reheat Isolation Valves Replacement project aims to replace the MS Stop and HR Isolation Valves at the Zeeland Generating Station (ZGS). During the Fall 2023 Steam Turbine Minor Inspection outage, a piece of stellite was found in the Main Steam (MS) strainer, indicating potential delamination from the MS Stop Isolation Valves. This delamination poses a risk of significant Domestic Object Damage (DOD) to the Steam Turbine, requiring immediate shutdown and lengthy repairs. The replacement project will ensure that no hard-faced material liberates due to delamination, as the new valves will be installed with proper Electric Power Research Institute (EPRI) techniques or better hard-facing materials. Objectives Mitigate forced shutdown risk due to stellite delamination. Ensure the new valves' hard-facing material bonds properly with the parent metal, preventing future delamination. Reduce significant costs and forced outage time due to Steam Turbine DOD. Alternatives Recommended: Replace MS Stop & HR Isolation Valves Details: Ensures no hard-faced material liberates due to delamination, using proper EPRI techniques or better hard-facing materials. Other Alternatives: Replace Only MS Stop Isolation Valves: Mitigates potential liberation from MS valves but not from RH valves. Costs about $1M less for materials and half of the previous labor estimate. Remove Stellite and Re-apply with EPRI Techniques (All Four Valves): Ensures no hard-faced material liberates due to delamination, but mixed results in the industry and difficult labor make this a non-viable option. No material cost, but labor cost is about twice the previous estimate ($2.6M). Model Assumptions Failure Impact: Forced outage of 550 MW, with a minimum 3-month derate. Significant savings if failure causes emergent repairs, as planned repairs would cost around $1M in MM compared to emergent repairs. Potential Capacity Losses: Calculated at $21,876,800 in the event of a forced shutdown. Three-year impact on capacity revenue included. CONE value used is $130,930, with 75% of CONE used for calculations. 10% chance of realizing this risk.

Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Unit - Plant
	Scope	Replace MS Stop & HR Isolation Valves This would ensure that no hard-faced material would liberate due to delamination as the new valves hard-facing would be installed with proper EPRI techniques or with a better hard-facing material that is proven to bond properly with the parent metal.
	Objectives	mitigate forced shutdown risk The Electric Power Research Institute (EPRI) has been following the stellite delamination failures and has helped develop a (costly) repair technique. Some valve vendors have developed better bonding methods of other hard-faced materials to parent metal, either equaling or exceeding the effectiveness of the EPRI-developed stellite repair methods. Specific to the ZGS 2A & 2B units, the industry has seen greater failure rates of stellite delamination in sliding parallel gate valves, which is same design of the 2A & 2B MS Stop Isolation Valves and 2A & 2B Hot Reheat (HR) Isolation Valves at ZGS. The steam path past the MS Stop Isolation Valves goes directly to the High Pressure (HP) Steam Turbine section, and the steam path past the HR Isolation Valves goes directly to the Intermediate Pressure (IP) then to the Low Pressure (LP) Steam Turbine sections. This replacement project plans to mitigate any future stellite liberations from the 2A & 2B MS Stop Isolation Valves and 2A & 2B Hot Reheat (HR) Isolation Valves, thereby mitigating significant costs and forced outage time due to Steam Turbine DOD.
	Planner Recommended Alternative	Replace MS Stop & HR Isolation Valves This would ensure that no hard-faced material would liberate due to delamination as the new valves hard-facing would be installed with proper EPRI techniques or with a better hard-facing material that is proven to bond properly with the parent metal. other alternatives: Replace Only MS Stop Isolation Valves This would mitigate the potential for the MS valves to have no further liberation (from where ZGS has seen liberation before). However, this would not mitigate the same failure potential from the RH valves which are the same design and susceptible to the same failure. This would cost about $1M less for materials and about half of the previous labor estimate. Remove stellite and re-apply with techniques from EPRI (all four valves): This should ensure that no hard-faced material would liberate due to delamination. However, there are mixed results in the industry for the effectiveness of the EPRI installation technique. The labor to do this with the valves in place may also prove to be difficult or almost impossible, making this a non-viable option. This would have no material cost and would cost about twice of the previous labor estimate. ($2.6M)

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002987	**2028**	**1**	**Literal**

Investment Name	Scenario
ZGS - Main Steam & Hot Reheat Isolation Valves Replacement	**Draft**

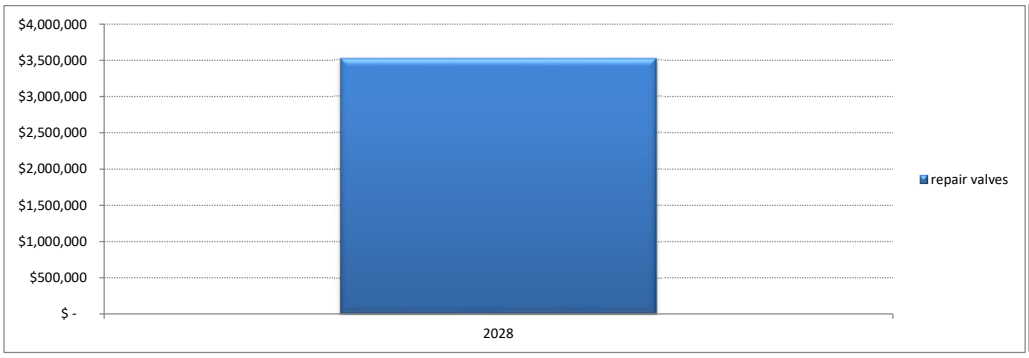
Value Function	**Consumers Energy Value Function**

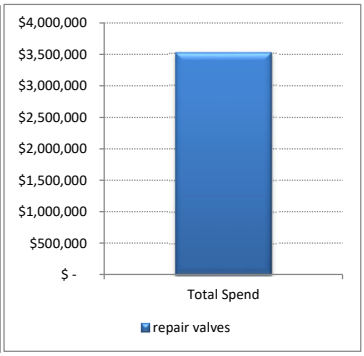
	Assumptions	If failure were to occur today: forced outage of 550 MW (all of Phase 2 would shut down due to Steam Turbine being inoperable). A 3-month derate would be the minimum – Valves repairs would likely be less than three months but depending on the Steam Turbine damage and parts availability three months may be too short. significant MM savings should a failure cause emergent repairs as to repair all four valves would cost around $1M in MM compared to planning ahead and that $1M being Capital (plus the cost of four new valves) with no Steam Turbine MM repairs (which would not be covered by the GE LTSA either). Steam Turbine DOD worth a minimum of $10M if MS Valves not replaced or minimum of $15M if the HR Valves not replaced in addition to $500k in valve repairs (for two valves, $500k more for the other two valves). A probability number is difficult to determine, but ZGS did catch a large piece of stellite in the MS strainer, as discovered in Fall 2023, and ZGS has four valves on which additional stellite liberation could occur, which could (in theory, and as has happened at least one time in the power industry) wear through a strainer to cause DOD to the Steam Turbine. 10% chance. Potential Capacity losses in the event of forced shutdown have been calculated at $21,876,800. The calculations were made using a conservative calculator provided by the capacity forecast team. Three-year impact on Capacity revenue is included in this number. The CONE value used for this model is $130,930. 75% of CONE was used for the calculations as customary. 10% chance of realizing this risk.
Alternative Details	repair valves	repair valves

Alternative Spend Profile

Name	Status		Total Spend	Alternative Start Date
repair valves	Recommended		$ 3,520,407	1/1/2028

Name	Status	2028
repair valves	Recommended	$ 3,520,407





Forecasts - Draft (repair valves)

Account Type	2028
Capital	$ 3,520,407
Cost Of Removal	$ -
O&M	$ -

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002363	**2026**	**16**	**Literal**

Investment Name	Scenario
ZGS - ST 2C Field Exchange and Generator Major Overhaul	**Draft**

Value Function	**Consumers Energy Value Function**

In power generation, a generator converts the mechanical energy of the associated turbine (steam/gas) to electrical energy, which is then transmitted to the grid through generator step-up transformers (GSU). The generator consists of two major components: a generator stator and a generator field/rotor. The field/rotor has a DC current applied to it to produce a DC magnetic field and is coupled to a prime mover (in this case, a steam turbine) that supplies rotational energy to the rotor, creating a rotating magnetic field. This rotating magnetic field induces voltage onto the 3-phase stator winding, which is then carried out through bushings to the GSU, where this voltage is stepped up to transmission level voltages.

Investment Type	Generation	Planning Portfolio	Zeeland
Facility	Zeeland / Zeeland		

Executive Summary	Problem Statement: Per the latest flux probe test conducted by GE in 2023, it is estimated that the generator field has at least one shorted turn. A shorted turn typically develops from dust/debris accumulated at turn-turn insulation or deteriorated field winding insulation. This adds electrical and mechanical stress to the machine, increasing generator rotor vibrations and heat dissipation. In the long term, the generator could continue to deteriorate, resulting in several shorted turns, at which point the field may not be able to build the required voltage to maintain generator terminal voltage and MVA. It is expected that the number of shorted turns will increase by 2028, and a field rewind/replacement is recommended. Several areas of dusting were identified in the generator stator during the borescope inspection in 2023. Moderate amounts of iron oxide dust were noted on the stator core and end winding axial supports. Oil leaks in the generator may eventually combine with the dust and form grease, which has low dielectric strength and may risk an internal flashover in the generator stator. During the minor outage of 2023, excessive grooving on the collector ring's brush riding surface was noted. Grooving leads to excessive brush wear and increased maintenance cost. GE recommends replacing the collector ring during the 2028 outage. Planner Recommended Alternative: Field exchange and generator major overhaul, including belly band tightening, core bolt tightening, and re-wedge of the generator stator. This work will require engineering and erecting a platform to pull out, store, and load the rotor on a truck. Other Alternatives Considered: Continue inspection and testing the generator during every minor and major outage. This is covered by the LTSA agreement and will incur no additional cost to Consumers Energy. However, this will not address the issue with shorted turns found in the field or any other issues noticed in the stator during the borescope inspection, which may lead to a forced outage on phase 2. The cost is reflective of the project-associated scope at a later year and may be much higher in the event of a forced outage on the steam turbine generator. Model Assumptions: Doing nothing may result in a catastrophic failure of the generator and a forced outage for at least two months. The probability of system failure without maintenance intervention is estimated at around 20-30% over the next few years, translating to about a 5% probability of failure each year. Potential capacity losses in the event of forced shutdown have been calculated at $12,604,129, based on a conservative model using 75% of the CONE value ($130,930). A 3% probability of realizing this risk was assumed given the copperleaf software constraints.

Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Unit - Plant
	Scope	Design and construct a platform to pull out the generator rotor. Generator field exchange. Belly band tightening. Core bolt tightening. Re-wedge.
	Objectives	Mitigate forced shutdown risk Detailed benefits: Shorted Turns in the Generator Field: The presence of at least one shorted turn, as identified in the 2023 flux probe test, indicates existing electrical and mechanical stress. If left unaddressed, the number of shorted turns is expected to increase, leading to higher vibrations and heat dissipation. This could eventually prevent the generator from maintaining terminal voltage and MVA. Dust and Debris Accumulation: The presence of iron oxide dust and oil leaks forming grease with low dielectric strength poses a risk of internal flashover in the generator stator. This condition, if not rectified, can lead to significant damage and potential failure. Collector Ring Wear: Excessive grooving on the collector ring's brush riding surface can lead to increased maintenance costs and potential failure of the DC field energizing system. This issue, if not addressed, can cause operational disruptions.
	Planner Recommended Alternative	Field Exchange and Generator Major Overhaul. Other alternatives considered: Continue inspection and testing the generator every minor and major outage. This is covered by the LTSA agreement and will incur no additional cost to Consumers Energy. However, this will not address the issue with shorted turns found in the field or any other issues noticed in the stator during the borescope inspection, which may lead to a forced outage on phase 2. The cost is reflective of the project-associated scope at a later year and may be much higher in the event of a forced outage on the steam turbine generator.

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002363	**2026**	**16**	**Literal**

Investment Name	Scenario
ZGS - ST 2C Field Exchange and Generator Major Overhaul	**Draft**

Value Function	**Consumers Energy Value Function**

	Assumptions	Doing nothing may result in a catastrophic failure of the generator and a forced outage for at least 2 months. Based on the provided text and general knowledge about generators at large gas plants, the probability of system failure if no maintenance is performed can be significant. Justification is as follows: Given these factors, the probability of system failure without any maintenance intervention is relatively high. The exact probability can vary but based on industry standards and the specific issues identified, it could be estimated at around 20-30% over the next few years. This estimate considers the cumulative impact of multiple failure points and the critical nature of the identified issues. To translate this into a yearly probability, we can use the concept of the annual failure rate (AFR). Assuming a 25% probability of failure over 5 years, there is about a 5% probability of failure each year. probability escalates to 10% on average from 2030 until 2040. Potential Capacity losses in the event of force shutdown have been calculated at $12,604,129. The calculations were made using a conservative calculator provided by the capacity forecast team. The CONE value used for this model is $130,930. 75% of CONE was used for the calculations as customary. 3% probability of realizing this risk was assumed as there is no way to enter 5% on the financial risk model.
Alternative Details	Field exchange and Generator stator repair	Field exchange and Generator stator repair.
	Continue inspection and testing the generator every minor and major outage	This is covered by the LTSA agreement and will incur no additional cost to Consumers Energy. However, this will not address the issue with shorted turns found in the field or any other issues noticed in the stator during the borescope inspection, which may lead to a forced outage on phase 2. The cost is reflective of the project-associated scope at a later year and may be much higher in the event of a forced outage on the steam turbine generator.

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002363	**2026**	**16**	**Literal**

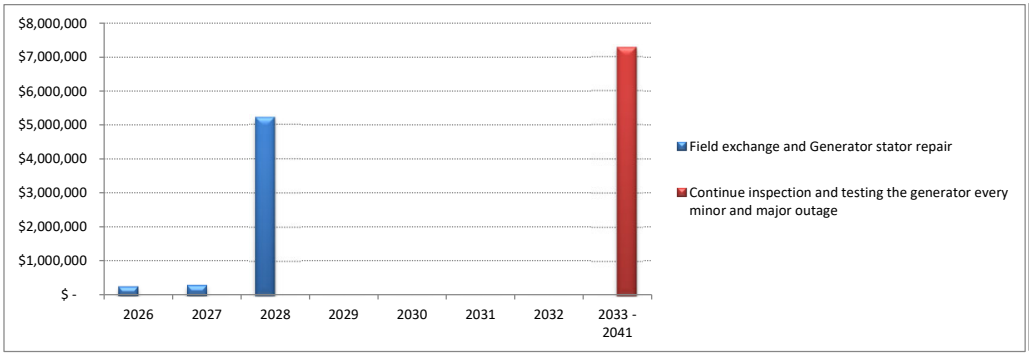
Investment Name	Scenario
ZGS - ST 2C Field Exchange and Generator Major Overhaul	**Draft**

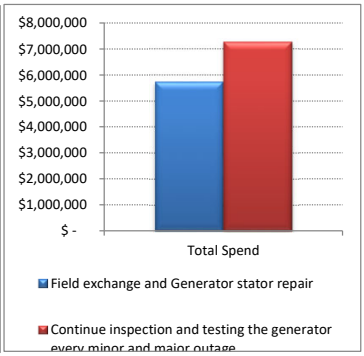
Value Function	Consumers Energy Value Function

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
Field exchange and Generator stator repair	Recommended	$ 5,740,093	1/1/2026
Continue inspection and testing the generator every minor and major outage	Candidate	$ 7,275,880	3/1/2033

Name	Status	2026	2027	2028	2029	2030	2031	2032	2033 - 2041
Field exchange and Generator stator repair	Recommended	$ 240,093	$ 280,000	$ 5,220,000	$ -	$ -	$ -	$ -	$ -
Continue inspection and testing the generator every minor and major outage	Candidate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,275,880





Forecasts - Draft (Field exchange and Generator stator repair)

Account Type	2026	2027	2028	2029	2030	2031	2032	2033 - 2041
Capital	$ 216,084	$ 252,000	$ 4,698,000	$ -	$ -	$ -	$ -	$ -
Cost Of Removal	$ 24,009	$ 28,000	$ 522,000	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002987	**2028**	**1**	**Literal**

Investment Name	Scenario
ZGS - Main Steam & Hot Reheat Isolation Valves Replacement	**Draft**

Value Function	**Consumers Energy Value Function**

During the Fall 2023 Steam Turbine Minor Inspection outage at the Zeeland Generating Station (ZGS), a roughly 2.5" x 0.5" piece of stellite was found in the Main Steam (MS) strainer, which is just upstream of the MS Stop/Control Valves. The only potential areas from where this stellite could have originated is either the 2A or 2B MS Non-Return Valves (NRVs) or the 2A or 2B MS Stop Isolation Valves. The MS NRVs were already planned for replacement for other reliability reasons during the Fall 2024 Outage, which was complete. When the valves were removed from 2A and 2B, they were inspected to find no evidence of failure of the stellite seat and trim. That leaves the origination of the stellite piece found in the Fall 2023 Outage as coming from the 2A or 2B MS Stop Isolation Valves. Upon further investigation, numerous valve vendors confirmed that the industry has seen many failures of stellite delaminating from a valve body's parent metal to be sent to the downstream Stop/Control Valves. The strainer should catch these potential pieces, but in at least one case in the power industry, a piece wore a hole through the strainer, sending it to the Steam Turbine path causing significant Domestic Object Damage (DOD), requiring immediate shutdown and lengthy repairs for that unit.

Investment Type	Generation	Planning Portfolio	Zeeland
Facility	Zeeland / Zeeland		

Executive Summary	The ZGS - Main Steam & Hot Reheat Isolation Valves Replacement project aims to replace the MS Stop and HR Isolation Valves at the Zeeland Generating Station (ZGS). During the Fall 2023 Steam Turbine Minor Inspection outage, a piece of stellite was found in the Main Steam (MS) strainer, indicating potential delamination from the MS Stop Isolation Valves. This delamination poses a risk of significant Domestic Object Damage (DOD) to the Steam Turbine, requiring immediate shutdown and lengthy repairs. The replacement project will ensure that no hard-faced material liberates due to delamination, as the new valves will be installed with proper Electric Power Research Institute (EPRI) techniques or better hard-facing materials. Objectives Mitigate forced shutdown risk due to stellite delamination. Ensure the new valves' hard-facing material bonds properly with the parent metal, preventing future delamination. Reduce significant costs and forced outage time due to Steam Turbine DOD. Alternatives Recommended: Replace MS Stop & HR Isolation Valves Details: Ensures no hard-faced material liberates due to delamination, using proper EPRI techniques or better hard-facing materials. Other Alternatives: Replace Only MS Stop Isolation Valves: Mitigates potential liberation from MS valves but not from RH valves. Costs about $1M less for materials and half of the previous labor estimate. Remove Stellite and Re-apply with EPRI Techniques (All Four Valves): Ensures no hard-faced material liberates due to delamination, but mixed results in the industry and difficult labor make this a non-viable option. No material cost, but labor cost is about twice the previous estimate ($2.6M). Model Assumptions Failure Impact: Forced outage of 550 MW, with a minimum 3-month derate. Significant savings if failure causes emergent repairs, as planned repairs would cost around $1M in MM compared to emergent repairs. Potential Capacity Losses: Calculated at $21,876,800 in the event of a forced shutdown. Three-year impact on capacity revenue included. CONE value used is $130,930, with 75% of CONE used for calculations. 10% chance of realizing this risk.

Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Unit - Plant
	Scope	Replace MS Stop & HR Isolation Valves This would ensure that no hard-faced material would liberate due to delamination as the new valves hard-facing would be installed with proper EPRI techniques or with a better hard-facing material that is proven to bond properly with the parent metal.
	Objectives	mitigate forced shutdown risk The Electric Power Research Institute (EPRI) has been following the stellite delamination failures and has helped develop a (costly) repair technique. Some valve vendors have developed better bonding methods of other hard-faced materials to parent metal, either equaling or exceeding the effectiveness of the EPRI-developed stellite repair methods. Specific to the ZGS 2A & 2B units, the industry has seen greater failure rates of stellite delamination in sliding parallel gate valves, which is same design of the 2A & 2B MS Stop Isolation Valves and 2A & 2B Hot Reheat (HR) Isolation Valves at ZGS. The steam path past the MS Stop Isolation Valves goes directly to the High Pressure (HP) Steam Turbine section, and the steam path past the HR Isolation Valves goes directly to the Intermediate Pressure (IP) then to the Low Pressure (LP) Steam Turbine sections. This replacement project plans to mitigate any future stellite liberations from the 2A & 2B MS Stop Isolation Valves and 2A & 2B Hot Reheat (HR) Isolation Valves, thereby mitigating significant costs and forced outage time due to Steam Turbine DOD.
	Planner Recommended Alternative	Replace MS Stop & HR Isolation Valves This would ensure that no hard-faced material would liberate due to delamination as the new valves hard-facing would be installed with proper EPRI techniques or with a better hard-facing material that is proven to bond properly with the parent metal. other alternatives: Replace Only MS Stop Isolation Valves This would mitigate the potential for the MS valves to have no further liberation (from where ZGS has seen liberation before). However, this would not mitigate the same failure potential from the RH valves which are the same design and susceptible to the same failure. This would cost about $1M less for materials and about half of the previous labor estimate. Remove stellite and re-apply with techniques from EPRI (all four valves): This should ensure that no hard-faced material would liberate due to delamination. However, there are mixed results in the industry for the effectiveness of the EPRI installation technique. The labor to do this with the valves in place may also prove to be difficult or almost impossible, making this a non-viable option. This would have no material cost and would cost about twice of the previous labor estimate. ($2.6M)

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002987	**2028**	**1**	**Literal**

Investment Name	Scenario
ZGS - Main Steam & Hot Reheat Isolation Valves Replacement	**Draft**

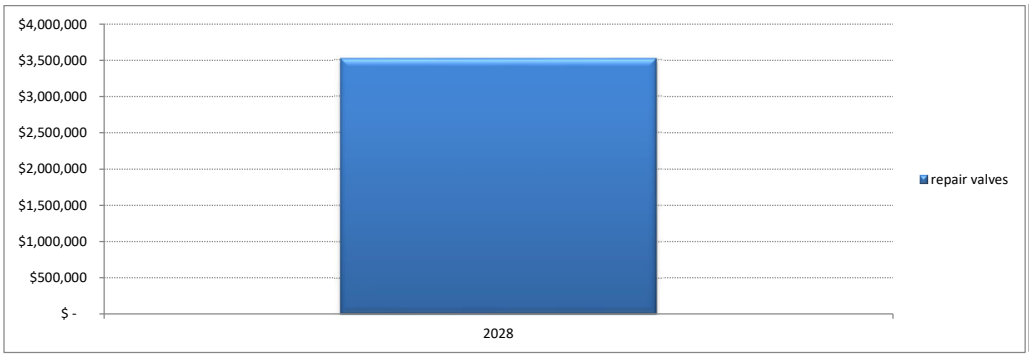
Value Function	**Consumers Energy Value Function**

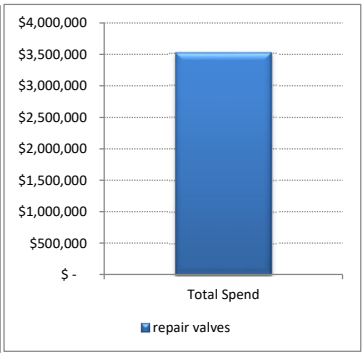
	Assumptions	If failure were to occur today: forced outage of 550 MW (all of Phase 2 would shut down due to Steam Turbine being inoperable). A 3-month derate would be the minimum – Valves repairs would likely be less than three months but depending on the Steam Turbine damage and parts availability three months may be too short. significant MM savings should a failure cause emergent repairs as to repair all four valves would cost around $1M in MM compared to planning ahead and that $1M being Capital (plus the cost of four new valves) with no Steam Turbine MM repairs (which would not be covered by the GE LTSA either). Steam Turbine DOD worth a minimum of $10M if MS Valves not replaced or minimum of $15M if the HR Valves not replaced in addition to $500k in valve repairs (for two valves, $500k more for the other two valves). A probability number is difficult to determine, but ZGS did catch a large piece of stellite in the MS strainer, as discovered in Fall 2023, and ZGS has four valves on which additional stellite liberation could occur, which could (in theory, and as has happened at least one time in the power industry) wear through a strainer to cause DOD to the Steam Turbine. 10% chance. Potential Capacity losses in the event of forced shutdown have been calculated at $21,876,800. The calculations were made using a conservative calculator provided by the capacity forecast team. Three-year impact on Capacity revenue is included in this number. The CONE value used for this model is $130,930. 75% of CONE was used for the calculations as customary. 10% chance of realizing this risk.
Alternative Details	repair valves	repair valves

Alternative Spend Profile

Name	Status		Total Spend	Alternative Start Date
repair valves	Recommended		$ 3,520,407	1/1/2028

Name	Status	2028
repair valves	Recommended	$ 3,520,407





Forecasts - Draft (repair valves)

Account Type	2028
Capital	$ 3,520,407
Cost Of Removal	$ -
O&M	$ -

EXHIBIT A-219 (MEW-26)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-220 (MEW-27)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-221 (MEW-28)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-222 (MEW-29)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-223 (MEW-30)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002195	**2025**	**4**	**Literal**

Investment Name	Scenario
JGS - Generator Step Up Transformer (GSU) Site Spare	**Draft**

Value Function	**Consumers Energy Value Function**

The Jackson Generating Station (JGS) relies on its main Generator Step-Up (GSU) transformers to transmit power generated from its units to the grid. These GSUs are a single point of failure, meaning that a failure of any GSU could result in a significant loss of power generation. Depending on the unit affected, the potential generation loss could range from 47 MW to 104 MW. This presents a substantial operational risk, as the lead time for procuring a new GSU is around 3 years. This extended lead time is primarily because each transformer of this size is custom-built, requiring specialized raw materials and engineering, much like the Covert GSU project. Given the significant derate risk, any GSU failure would cause an extended derate, during which replacement procurement would be highly delayed.
Based on the current assessment of the existing generator start-up transformer, the probability of failure is currently estimated at 5%. This probability is projected to escalate by 5% annually. Given that the industry life expectancy for GSU transformers of this vintage is approximately 20 years, and these units have already reached that timeframe, the risk of failure is increasingly likely. As the GSUs age beyond their expected lifespan, the likelihood of failure grows, raising concerns about both operational reliability and financial impacts.
While Consumers Energy has spare transformers at other sites, such as Campbell, Karn, Lake Winds, and Crosswinds, none of these spares are compatible with the specific voltage requirements (138kV-13.2kV-13.2kV) or winding configuration (WYE-DELTA) needed at JGS. To address this in the short term, an O&M-funded project aimed to secure a spare GSU sharing and leasing agreement with Midland Cogeneration Venture (MCV) to cover a potential transformer failure at JGS. However, the failure to reach an agreement with MCV in 2024 has left JGS without an immediate backup solution, escalating the risk of prolonged derates.

Investment Type	Generation	Planning Portfolio	Jackson
Facility	Jackson / Jackson		
Executive Summary	The Jackson Generating Station (JGS) relies on its main Generator Step-Up (GSU) transformers to transmit power from its generating units to the grid. These GSUs represent a single point of failure: a loss of any GSU would immediately force a significant derate and disrupt operations. Procurement of a replacement GSU requires custom engineering and specialized materials, resulting in lead times of approximately three years, which exposes JGS to prolonged operational and financial risk. Existing spare transformers at other Consumers Energy sites (Campbell, Karn, Lake Winds, Crosswinds) are not compatible with JGS's voltage (138 kV–13.2 kV–13.2 kV) and winding configuration (WYE–DELTA). Previous efforts to secure a lease agreement with Midland Cogeneration Venture (MCV) failed in 2024, leaving JGS without a viable short-term backup solution. This reinforces the need for a dedicated on-site spare GSU to mitigate extended derate risk. Updated Modeling Approach (Copperleaf): • Derate Magnitude: 104 MW (planning basis), reflecting both LMs offline for an LM-tied GSU failure. Sensitivity ranges: ~90 MW (STG), 131–135 MW (LM), 136–145 MW (7EA). • Restoration Window: ~1,080 days (≈3 years) for procurement and commissioning. • Copperleaf Limitation: Lost Generation Risk module caps outage duration at 365 days, making energy-loss valuation conservative versus the true exposure. The Financial Risk leg still reflects full multi-year capacity impacts. • Probability Curve: 5% in 2026, increasing by 5 percentage points annually through December 2039. • Capacity Value: $28 million exposure for a 104 MW, 1,080-day derate based on MISO's rolling 3-year ZRC accreditation methodology and 75% CONE ($127,135). • Energy Value: Uses historical and forecasted capacity factors from the current PSCR case, incorporating NOx/CO limits and the site's "adder" operating practice. Copperleaf Risk and Investment Outputs (NPV in $000): • Financial Risk (Capacity Revenue Loss): 9,599 • Lost Generation Risk (104 MW Derate): 6,774 • Total Investment Cost (Spare GSU): -4,423 • Total Value: 11,951 Recommended Alternative: Purchase and store a spare GSU on-site at JGS • Estimated cost: $5 million (includes transformer and storage pad). • Benefits: Immediate access to a compatible spare, elimination of dependency on external agreements, mitigation of prolonged derate risk, and alignment with Copperleaf-based risk-adjusted valuation. Other Alternative Considered: Lease a Spare Transformer and Overhaul Failed GSU • Estimated cost: $10.8 million plus ongoing rental fees. • Limitation: No rental units meet JGS's voltage and winding specifications; prior MCV lease attempt failed.		
Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Unit - Plant
	Scope	Create bid specification for design of a spare Jackson Generating Station Main Generator Step Up Transformer (GSU) Create specification for the JGS spare GSU storage area (foundation and power if needed) Bid out and procure spare JGS GSU Provide onsite quality oversight of manufacturing at the facility. Bid out and install spare GSU storage area in time for receipt of the spare GSU.
	Objectives	This project provides JGS with a reliable spare GSU it currently does not have access to. In parallel with this project, CE is entering a shared spare lease agreement with Midland CoGeneration (MCV) in the 3rd or 4th quarter of 2023 via O&M funding to provide immediate short-term availability of a spare GSU for the site if needed. However, this agreement does have terms and conditions such that MCV can reject our request to use their spare GSU should they be in need of the spare or intend to use otherwise at their discretion, which is not a reliable plan for long term reliability for our customers. This will also mitigate the need to continue to carry the MCV lease agreement O&M expense ($60K/yr) once this spare GSU is close to delivery at site, saving future O&M spend on this agreement through the remaining life of the plant.

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002195	**2025**	**4**	**Literal**

Investment Name	Scenario
JGS - Generator Step Up Transformer (GSU) Site Spare	**Draft**

Value Function	**Consumers Energy Value Function**

	Planner Recommended Alternative	Purchase new spare GSU transformer This option involves the procurement and long-term storage of a spare Generator Step-Up (GSU) transformer at the Jackson Generating Station (JGS). The estimated cost for this approach is $5 million, which includes the purchase of the spare GSU and the installation of a dedicated storage area or pad to ensure its safe preservation until needed. Rationale for Selection Purchasing and storing a spare GSU on-site at JGS is the most cost-effective, predictable, and reliable long-term strategy to mitigate potential losses and operational disruptions in the event of a GSU failure or overhaul. This solution provides JGS with a dedicated spare transformer that is immediately accessible when required, ensuring minimal downtime and avoiding costly delays associated with the procurement of a replacement unit. Other alternative considered: Lease a Spare Transformer, Overhaul the Failed GSU (If Repairable) This option examines the viability of leasing a GSU transformer. It entails obtaining and installing a rental GSU transformer if there is a failure, while the faulty GSU is dispatched for repairs, assuming it can be overhauled. This approach is estimated to cost approximately $10.8 million, based on similar scope projects, including the Zeeland Generating Station. The breakdown of costs includes $400,000 per month for the rental unit ($4.8 million per year), $3 million to overhaul the failed GSU if repairable within a one-year timeframe and an additional $3 million to remove, transport and install both the rental unit and the failed GSU. There are significant limitations to this option, primarily stemming from the unavailability of rental transformers with the specific voltage requirements (138kV-13.2kV-13.2kV) and winding configuration (WYE-DELTA) necessary for JGS. This means that leasing a spare GSU is not currently viable, as no rental units meet the unique specifications required for JGS operations.
	Assumptions	Technical failure mode: • Transformer configuration: Each LM GSU has one high-side connection and two low-side connections (one per LM). Practical isolation of a single LM on a failed GSU is not possible; both LMs tied to that GSU must be removed from service. • Planning basis: Maintain 104 MW derate for modeling consistency and technical accuracy (reflects both LMs offline for an LM-tied GSU failure). Sensitivity bands: ~90 MW (STG GSU), 131–135 MW (LM GSU), 136–145 MW (7EA GSU). • Restoration window: True economic exposure aligns with ~1,080 days (≈3 years) for procure/replace/commission. Copperleaf limitation (important conservatism): • Copperleaf Lost Generation Risk model allows a maximum outage duration of 365 days. We therefore enter 365 days in that module; this UNDERSTATES total energy loss vs. the true ~1,080-day exposure and is conservative. The Financial Risk (capacity) leg still reflects the full multi-year accreditation impact as described below. Probability of occurrence (annual schedule used in both risk legs): • 2026: 5%; 2027: 10%; 2028: 15%; then +5 percentage points per year through December 2039. Event treated as single-event loss applied in the year realized; probabilities apply only while no spare is in place. Capacity value methodology (Financial Risk leg): • Accreditation rule: MISO rolling 3-year average of ZRCs; any forced outage >30 days reduces accredited capacity for multiple subsequent years. • CONE basis: 75% of CONE = $127,135 (planning anchor). • Reference exposure: $28 million capacity value impact for a 104 MW, 1,080-day derate using the rolling ZRC methodology (used as the capacity consequence and then probability-weighted). • Market offer assumption: Unit not offered into the capacity market during extended derate; we quantify foregone capacity value only (no replacement capacity purchases). Energy (NEV) methodology (Lost Generation Risk leg): • Dispatch & capacity factor inputs: Use historical and forecast CF from the current PSCR case (not unconstrained Aurora). This corrects the earlier overstatement and aligns with portfolio standards. • Emissions constraints: Incorporate Jackson's NOx/CO limits and the site "adder" operating practice (weekly monitoring/offer adjustments) when shaping run-hours and margins. • Engine stall risk: Modeled as a separate operational risk (own probability and consequence) to avoid double counting. Lead time & alternatives:
Alternative Details	Purchase new spare GSU	Purchase new spare GSU

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Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002195	**2025**	**4**	**Literal**

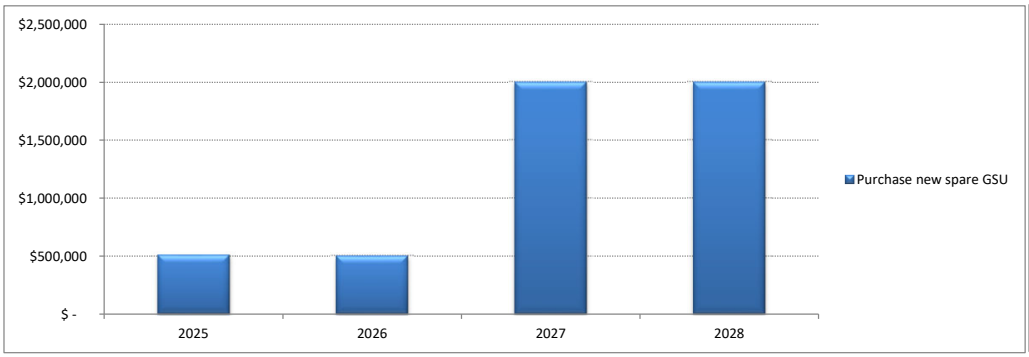
Investment Name	Scenario
JGS - Generator Step Up Transformer (GSU) Site Spare	**Draft**

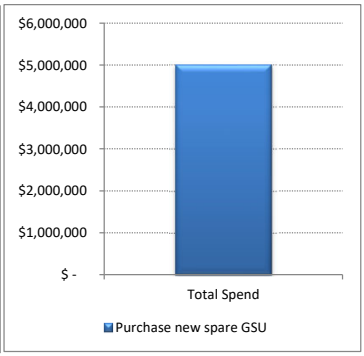
Value Function	**Consumers Energy Value Function**

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
Purchase new spare GSU	Recommended	$ 5,014,367	1/1/2025

Name	Status	2025	2026	2027	2028
Purchase new spare GSU	Recommended	$ 514,367	$ 500,000	$ 2,000,000	$ 2,000,000





Forecasts - Draft (Purchase new spare GSU)

Account Type	2025	2026	2027	2028
Capital	$ 514,367	$ 500,000	$ 2,000,000	$ 2,000,000
Cost Of Removal	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -

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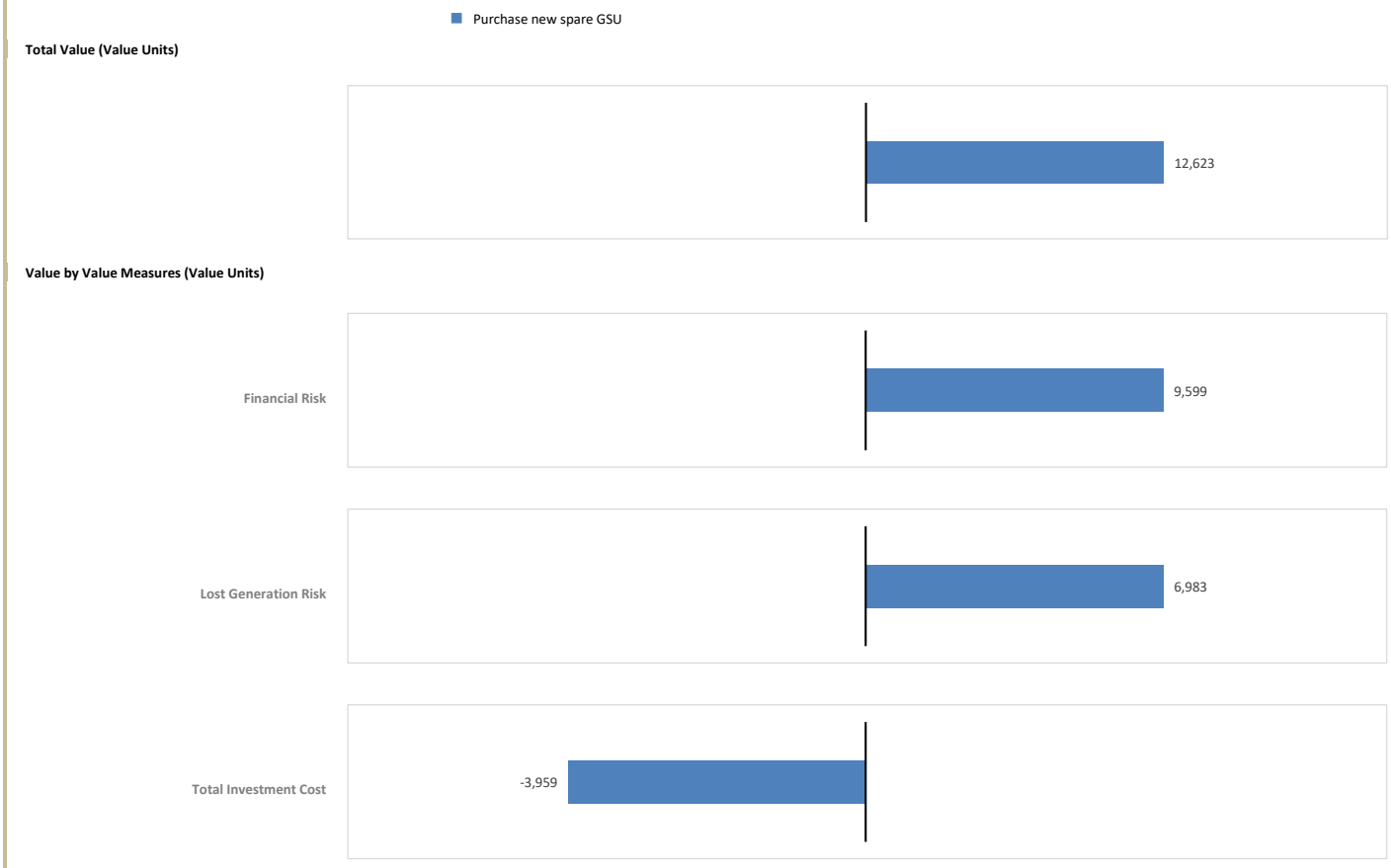
Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002195	2025	4	Literal

Investment Name	Scenario
JGS - Generator Step Up Transformer (GSU) Site Spare	Draft

Value Function	Consumers Energy Value Function

Alternative Value

Name	Status	Total Value	Cost Present Value	Value / $
Purchase new spare GSU	Recommended	$ 12,623	$ 3,958,601	0.0032



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Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002195	**2025**	**4**	**Literal**

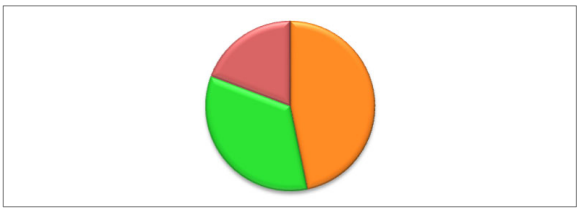
Investment Name	Scenario
JGS - Generator Step Up Transformer (GSU) Site Spare	**Draft**

Value Function	**Consumers Energy Value Function**

Purchase new spare GSU

Description	Purchase new spare GSU
Alternative Status	Recommended
Alternative Start Date	1/1/2025

Alternative Value



Value Function Measure	Value	Value in Percentage
Financial Risk	9,599	47%
Lost Generation Risk	6,983	34%
Total Investment Cost	(3,959)	19%
Total	**12,623**	**100%**

Alternative Value Details

Impacted Item					Value Model Name			Value Model			Value	
GEN002195 / JGS - Generator Step Up Transformer (GSU) Site Spare					Financial Risk Matrix			Financial Risk Matrix			9,599	
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**				
Financial Risk	Baseline		-	Value Unit	825	900	900	900				
Financial Risk	Outcome	2029	9,599	Value Unit	825	900	900	900				

Impacted Item					Value Model Name			Value Model			Value	
GEN002195 / JGS - Generator Step Up Transformer (GSU) Site Spare					Investment Cost			Investment Cost			(3,959)	
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**				
Total Investment Cost	Outcome	2025	(3,959)	Dollar	514,367	500,000	2,000,000	2,000,000				

Impacted Item					Value Model Name			Value Model			Value	
GEN002195 / JGS - Generator Step Up Transformer (GSU) Site Spare					Lost Generation Risk			Lost Generation Risk			6,983	
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**				
Lost Generation Risk	Baseline		-	Dollar	15,288	121,087	254,858	359,972				
Lost Generation Risk	Outcome	2029	6,983	Dollar	15,288	121,087	254,858	359,972				

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002192	**2025**	**5**	**Literal**

Investment Name	Scenario
JGS - LM1-6 VIGV(variable inlet guide vane) Project	**Draft**

Value Function	**Consumers Energy Value Function**

The gas turbines at Jackson Generating Station currently use fixed Inlet Guide Vanes (IGVs) that limit their ability to adapt to varying operating conditions. This results in suboptimal performance, reduced efficiency, and increased risks to turbine reliability. The following are the key challenges associated with the current system:
•Inefficiency of Fixed IGVs: The fixed angle of the IGVs restricts airflow modulation, preventing the turbines from operating at peak efficiency across different ambient conditions and power settings. This leads to inefficient fuel use, particularly at part load, which is common in load-following operations at Jackson Generating Station.
•Fuel Consumption and Heat Rate: Due to the inability of the current system to adjust for optimal airflow, the heat rate of the turbines is higher than necessary, which increases fuel consumption. The inefficiency becomes more pronounced during partial load conditions, where fuel savings are critical for economic operation.
•Increased Risk of Engine Stall: Without dynamic control of the IGV angles, the turbines are more susceptible to engine stalls during rapid power reductions or operational fluctuations. An engine stall can cause significant damage to the turbines, resulting in costly repairs and extended downtime.
•Dependence on Duct Firing: To meet power demands, the station relies on duct firing, which is less efficient, consumes more fuel, and places additional stress on the system. This dependency results in higher operational costs and increased emissions.

Investment Type	Generation	Planning Portfolio	Jackson
Facility	Jackson / Jackson		

Executive Summary	Jackson Generating Station plans to upgrade six LM6000PC units (LM1–LM6) from fixed to Variable Inlet Guide Vanes (VIGV) to improve efficiency, reliability, and dispatch flexibility under NOx-constrained capacity factors. Fixed IGVs limit airflow modulation, driving inefficient fuel use at part load, elevated heat rate, higher stall risk during rapid load changes, and reliance on less efficient duct firing. The VIGV system enables dynamic airflow control, increasing base-load capability and reducing duct firing without changing the site's ~560 MW (net) maximum output. Expected uplift is ~+12 MW at the gas turbines plus ~+15 MW at the steam turbine from increased exhaust energy, for a site-wide base-load increase of ~+27 MW. Heat rate improves by ~189 Btu/kWh at baseload (no duct); baseload HR improves from ~7,951 to ~7,762 Btu/kWh (LHV, no duct). Efficiency gains persist across the load range (≈2% at ~70% load). The upgrade increases stall margin, lowering the likelihood of damaging stall events during load-following and reducing unplanned downtime. Generation Shift: +12 MW gas turbine base load plus +15 MW steam from increased exhaust energy → ~+27 MW site-wide base-load capability. Site maximum remains ~560 MW (net), but generation shifts from duct firing to efficient base load. Fuel Efficiency: Heat rate improves by ~189 Btu/kWh at baseload (no duct). Baseload HR drops from ~7,951 to ~7,762 Btu/kWh (LHV, no duct). Efficiency gains persist across the load range (~2% at ~70% load). Reliability: Increased stall margin reduces risk of catastrophic stalls and unplanned outages. Model Assumptions Six LM6000PC units; heat-rate values on LHV basis.NOx-driven capacity factor limits incorporated using historical performance. Stall risk: ~1 event every 5 years; repair cost up to $7.4M per turbine. Copperleaf planning uses 10% probability and $5–$15M consequence range → ~$22.2M cumulative risk avoided over 15 years. Each stall causes ~90 MW derate for ~3 weeks (loaner engine install/remove included). Economic Impact Economic valuation has been revised from the initial Aurora run to a Copperleaf-based approach that (1) incorporates NOx-driven capacity factor limitations using historical performance and (2) explicitly prices stall risk and derate impacts. Value streams include fuel savings from lower heat rate, incremental base-load generation (with reduced duct firing), and avoided stall repairs and derate losses. A single stall can cost up to $7.4M per turbine (updated from $4M based on a recent LM306 engine stall event), with an underlying expectation of ~1 event every 5 years (~20% per five-year period). For planning within Copperleaf (tooling constraint), a conservative 10% probability with a $5–$15M consequence range is used, yielding an estimated cumulative consequence of ~$22.2M over 15 years that the VIGV upgrade helps mitigate. Each stall also drives an unplanned ~90 MW derate for ~3 weeks (≈1.5 weeks to install a loaner engine and ≈1.5 weeks to remove it post-repair). Financial Analysis Total Value of $11.035M in overall benefits from the VIGV upgrade, derived from: Fuel Savings: $8,188K,Financial Risk (stall avoidance): $5,300K, Lost Generation Risk: $133K, Total Investment Cost: –$2,587K Total value: $11,035K

Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Unit - Plant
	Scope	Install VIGV system on Engine Serial Number (ESN) 185-132 during its normally planned Major Overhaul interval April 2025 Install VIGV system on six other engines during their normally planned hot section interval: September 2025: ESN 191-312 April 2026: ESN 191-339 September 2026: ESN 191-307 April 2027: ESN 191-345 September 2027: ESN 191-306 April 2028: ESN 191-351
	Objectives	This upgrade will: •Increase Base Load Output: The VIGV system will enhance the base load capacity of the gas turbines by 12 MW and contribute to a total site-wide increase of 27 MW when combined with steam turbine improvements. This increase will reduce the reliance on inefficient duct firing. •Improve Fuel Efficiency: The upgrade will improve the baseload heat rate by approximately 189 Btu/kWh (without duct firing) and 286 Btu/kWh (with duct firing). •Enhance Stall Margin: By allowing better airflow control, the VIGV system will improve the stall margin, reducing the risk of turbine failure during rapid load changes and ensuring more reliable operation. This project is critical for improving the overall performance and efficiency of the turbines, reducing operational costs, and minimizing the risk of unplanned outages due to engine stalls.
	Planner Recommended Alternative	Install VIGV upgrade.

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002192	2025	5	Literal

Investment Name	Scenario
JGS - LM1-6 VIGV(variable inlet guide vane) Project	Draft

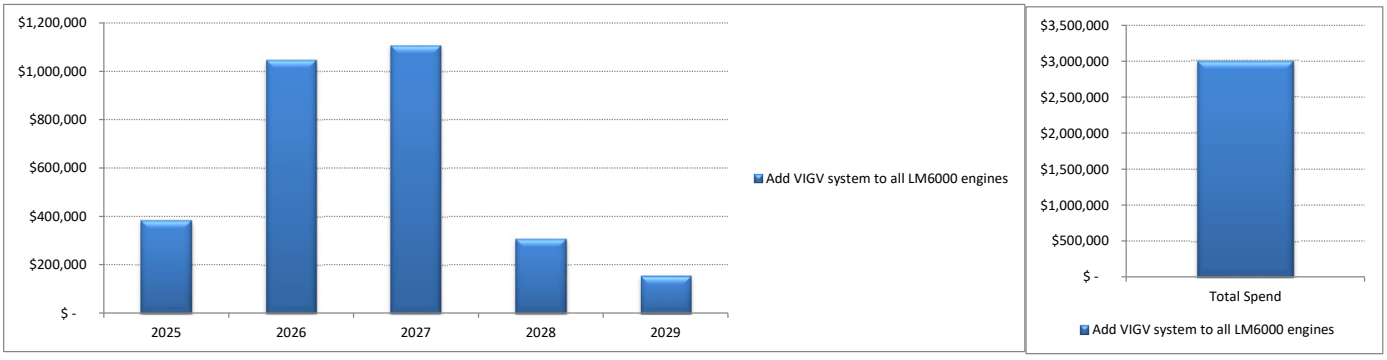
Value Function	Consumers Energy Value Function

	Assumptions	Revised economic modeling: The initial Aurora model did not account for the capacity factor limitation at the Jackson station from NOx emission limitations. Also, the engine stall risk was not included in this model. In order to accurately quantify the risk of the stalls and incorporate the accurate forecasted capacity factors based on historical performance, the approach to the value modeling was changed to a Copperleaf based approach. This will also align the business case with current practice post-adoption to the use of Copperleaf for business case generation. Fuel Efficiency Improvement Without the upgrade, the station will continue to operate with a heat rate of 7,951 Btu/kWh (LHV, assuming no duct burners used) for each LM6000PC turbine during base load operations. The VIGV upgrade would have reduced this heat rate to 7,7614 Btu/kWh (LHV, no duct burners used), leading to more efficient fuel usage and cost savings (heat rate improvement of 189 Btu/kWh across the entire load range). Refer to table in original concept approval for a summary of the increase in generation and heat rate impacts with and without VIGV. By not upgrading, the plant misses a significant MW improvement in output at lower heat rates without duct burners, and a considerable heat rate improvement of 189 Btu/kWh across the entire load range. This represents a significant loss in fuel savings and operational efficiency over time. Risk of stall event: $7.4M repair costs from stalls. expect to have a stall every 5 years. Three stalls over the next 15 years. $22.2M total risk. Stall Risk: The existing fixed IGV system increases the risk of engine stalls, particularly during rapid load reductions. An engine stall is a critical failure that can lead to catastrophic damage, requiring costly repairs. The estimated cost of an engine stall repair is up to $7.4 million per turbine (number updated from $4M based on recent 306 engine stall event updated costs), with an average stall probability of one occurrence every five years (20%). Due to Copperleaf software limitations a conservative probability of 10% with a consequence of $5M-$15M will be used for planning purposes. Over the next 15 years, the overall consequence is estimated at $22.2 million in repair costs that will be mitigated by the VIGV system. The stall events also result in a 90MW unplanned derate for a total of three weeks. It takes about 1.5 weeks for the loaner replacement engine to be delivered and installed and then another 1.5 weeks to uninstall once the repairs are completed on the failed engine. A 20% probability of realizing this risk every 5 years will be assumed for planning purposed.
Alternative Details	Add VIGV system to all LM6000 engines	Per Unit (x6): 2 MW output gain without duct firing, greater than 2% fuel efficiency gain at part load, exhaust energy increase of 3%, and greater protection from an engine stall condition. (Assumptions: $575K for 6 engines + $150K for 1 engine. Cost estimates include hardware, software, engineering, and labor for installation plus loadings.)

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
Add VIGV system to all LM6000 engines	Recommended	$ 2,993,559	1/1/2025

Name	Status	2025	2026	2027	2028	2029
Add VIGV system to all LM6000 engines	Recommended	$ 380,949	$ 1,046,370	$ 1,107,600	$ 305,760	$ 152,880



Forecasts - Draft (Add VIGV system to all LM6000 engines)

Account Type	2025	2026	2027	2028	2029
Capital	$ 341,149	$ 941,733	$ 996,840	$ 275,184	$ 137,592
Cost Of Removal	$ 39,801	$ 104,637	$ 110,760	$ 30,576	$ 15,288
O&M	$ -	$ -	$ -	$ -	$ -

Concept Approval Internal Report

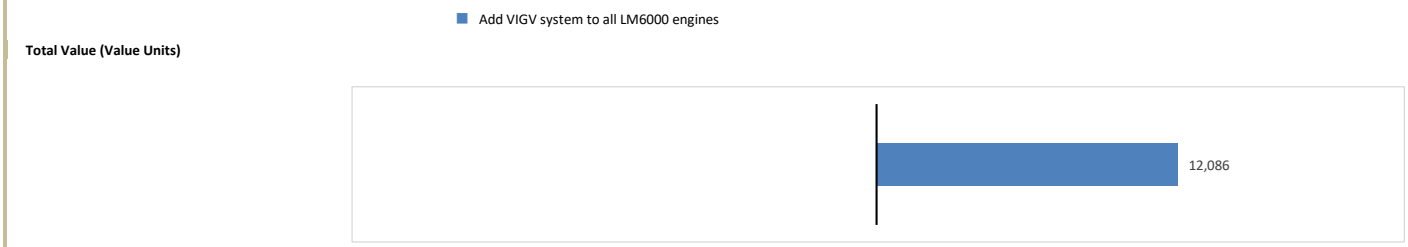
Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002192	2025	5	Literal

Investment Name	Scenario
JGS - LM1-6 VIGV(variable inlet guide vane) Project	Draft

Value Function	Consumers Energy Value Function

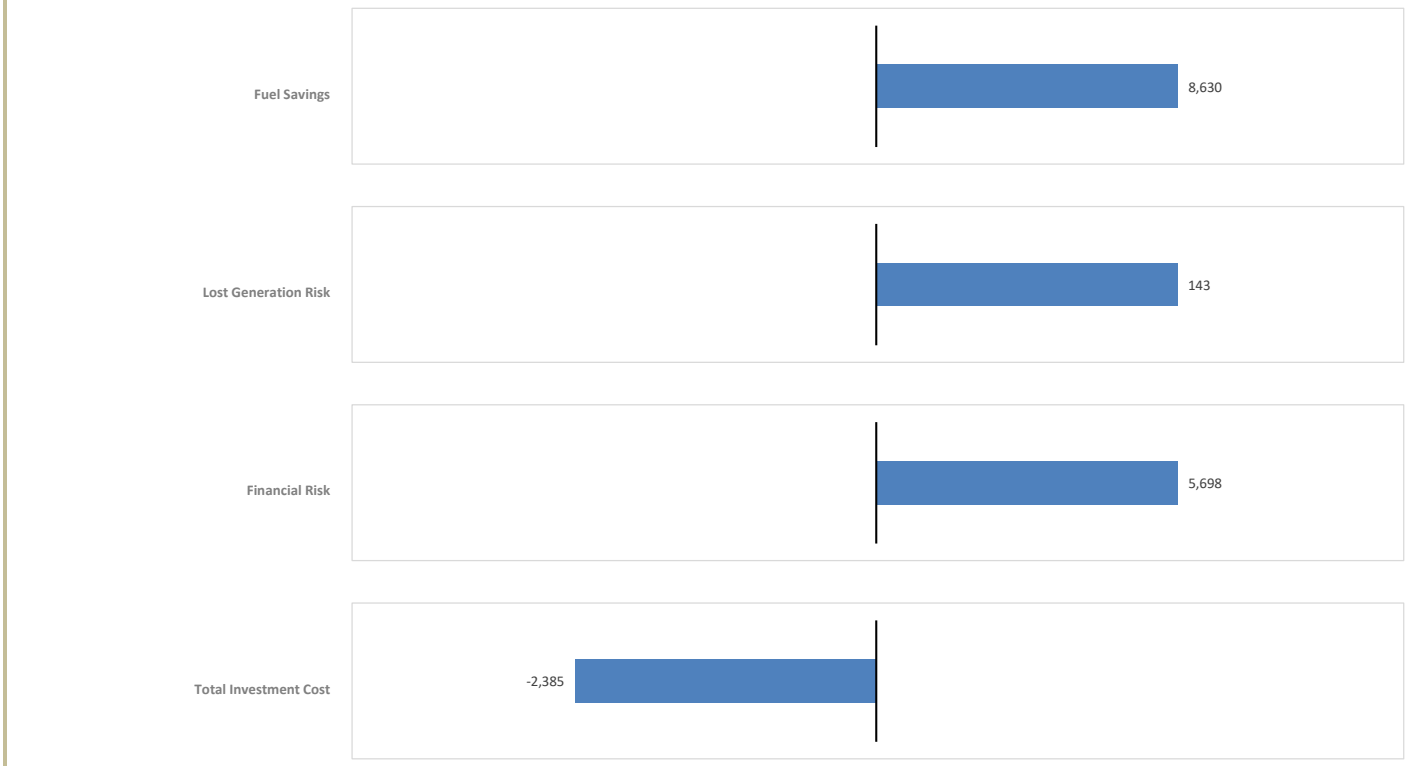
Alternative Value

Name	Status	Total Value	Cost Present Value	Value / $
Add VIGV system to all LM6000 engines	Recommended	$ 12,086	$ 2,384,512	0.0051



Total Value (Value Units)

Value by Value Measures (Value Units)



Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002192	**2025**	**5**	**Literal**

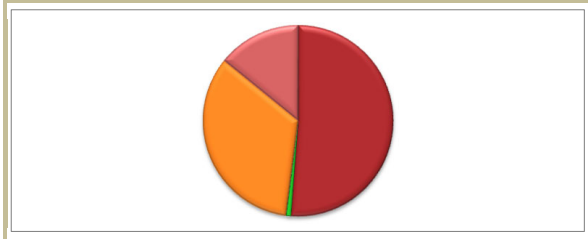
Investment Name	Scenario
JGS - LM1-6 VIGV(variable inlet guide vane) Project	**Draft**

Value Function	**Consumers Energy Value Function**

Add VIGV system to all LM6000 engines

Description	Per Unit (x6): 2 MW output gain without duct firing, greater than 2% fuel efficiency gain at part load, exhaust energy increase of 3%, and greater protection from an engine stall condition. (Assumptions: $575K for 6 engines + $150K for 1 engine. Cost estimates include hardware, software, engineering, and labor for installation plus loadings.)
Alternative Status	Recommended
Alternative Start Date	1/1/2025

Alternative Value



Value Function Measure	Value	Value in Percentage
Fuel Savings	8,630	51%
Lost Generation Risk	143	1%
Financial Risk	5,698	34%
Total Investment Cost	(2,385)	14%
Total	**12,086**	**100%**

Alternative Value Details

Impacted Item					Value Model Name			Value Model			Value
GEN002192 / JGS - LM1-6 VIGV(variable inlet guide vane) Project					Financial Risk Matrix			Financial Risk Matrix			5,698
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**	**2029**		
Financial Risk	Baseline		-	Value Unit	250	1,000	1,000	1,000	1,000		
Financial Risk	Outcome	2030	5,698	Value Unit	250	1,000	1,000	1,000	1,000		

Impacted Item					Value Model Name			Value Model			Value
GEN002192 / JGS - LM1-6 VIGV(variable inlet guide vane) Project					Heat Rate Impact			Heat Rate Impact			8,630
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**	**2029**		
Fuel Savings	Outcome	2030	8,630	Dollar	0	0	0	0	0		

Impacted Item					Value Model Name			Value Model			Value
GEN002192 / JGS - LM1-6 VIGV(variable inlet guide vane) Project					Investment Cost			Investment Cost			(2,385)
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**	**2029**		
Total Investment Cost	Outcome	2025	(2,385)	Dollar	380,949	1,046,370	1,107,600	305,760	152,880		

Impacted Item					Value Model Name			Value Model			Value
GEN002192 / JGS - LM1-6 VIGV(variable inlet guide vane) Project					Lost Generation Risk			Lost Generation Risk			143
Value Measure	**Type**	**Impact Year**	**Value**	**Unit**	**2025**	**2026**	**2027**	**2028**	**2029**		
Lost Generation Risk	Baseline		-	Dollar	3,045	21,564	23,540	22,601	22,374		
Lost Generation Risk	Outcome	2030	143	Dollar	3,045	21,564	23,540	22,601	22,374		

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002684	**2026**	**8**	**Literal**

Investment Name	Scenario
JGS Unit 7 Gas Turbine Rotor Replacement	**Draft**

Value Function	**Consumers Energy Value Function**

The rotor for a GE 7EA gas turbine has a life limit of either 5000 starts or 250,000 running hours. JGS Unit 7 (GE 7EA GT) gas turbine rotor is expected to hit its limit for starts before hitting its limit for running hours in the year 2032. JGS Unit 7 has planned maintenance intervals, either major overhaul or hot gas path, approximately every 5 years. The next major overhaul is tentatively in 2028 and the next hot gas path tentatively 2034. Based on the running profile of JGS, the unit will not be allowed to operate with the current rotor until 2034, and it would be unwise to take an additional outage between 2029 & 2034 to replace the rotor when it can be done in 2028.

Investment Type	Generation	Planning Portfolio	Jackson
Facility	Jackson / Jackson		

Executive Summary

The Jackson Generating Station Unit 7 Gas Turbine Rotor Replacement project is a critical initiative to ensure long-term reliability and efficiency of the GE 7EA gas turbine. Recent operational changes and updated forecasts have shifted the preferred strategy for rotor replacement.
Key Updates

Unit 7 Operational Change:

Expected to run as a baseload unit starting in 2026, significantly increasing operating hours compared to current cycling operations.
If Unit 7 operates as baseload and is separated as its own node, a refurbished rotor will not have sufficient hours to last until 2041.
Continuing current operations would allow a refurbished rotor to meet the 2041 target, but this scenario is no longer expected.

Rotor Replacement Options
New 7EA Rotor: Provides 5,000 starts / 128,000 operating hours.
Ensures turbine life through 2041 under baseload conditions.

Refurbished 7EA Rotor: Provides 4,500 starts / 95,000 operating hours.
Insufficient for 2041 if baseload operation begins in 2026.

Preferred Option: Install a new rotor. This approach avoids additional outages and ensures compliance with the new operating profile. Estimated cost: $3,622,500 .

Refurbished Rotor Alternative: Estimated cost: $2,976,102.
Would require additional outage and replacement before 2041, increasing total lifecycle costs.

Savings Assumption: Approximately $2.8M in avoided costs when factoring inflation, additional outage time, and resource requirements for a second replacement.

Rotor life limit: 5,000 starts or 250,000 hours.
Current rotor expected to reach start limit by 2032, before hour limit.
Replacing during 2028 major overhaul prevents an extra 40-day outage and mitigates high failure risk after 2032.

Recommendation: Proceed with new rotor replacement during the 2028 major overhaul to align with baseload operation plans, minimize lifecycle costs, and ensure reliable operation through 2041.

Last Approver	Thompson, Cornelius (CORNELIUS.THOMPSONJR@CMSENERGY.COM)	Approval Date	1/7/2025

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 3
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Major Equipment
	Scope	Replace the rotor with new. GE engineering, as part of product design, determined what the finite operating life of the 7EA class rotor. This determination is based on the design, the materials used in the design, material degradation, and low-cycle fatigue from the thermal cycling associated with frequent starts and stops.
	Objectives	Mitigate forced outage risk and maximize savings by optimizing execution timing.
	Planner Recommended Alternative	Replace in 2028, avoid another potential 40-day unit outage in-between cycles, reset rotor life. A refurbished rotor typically costs 50% of a new rotor. There are some refurbished rotors on hand versus the 12–14-month lead time minimum for a new rotor. The 95,000 hours operating life of a refurbished rotor. The lifespan of the refurbished rotor could be longer if the unit becomes a baseload unit instead of a peaking unit. Other alternatives: Replace rotor in 2032: Additional costs incurred Replace with new: costs twice the price, only get 11% more starts and 35% more hours. Does not make sense for our unit at this time.

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002684	2026	8	Literal

Investment Name	Scenario
JGS Unit 7 Gas Turbine Rotor Replacement	Draft

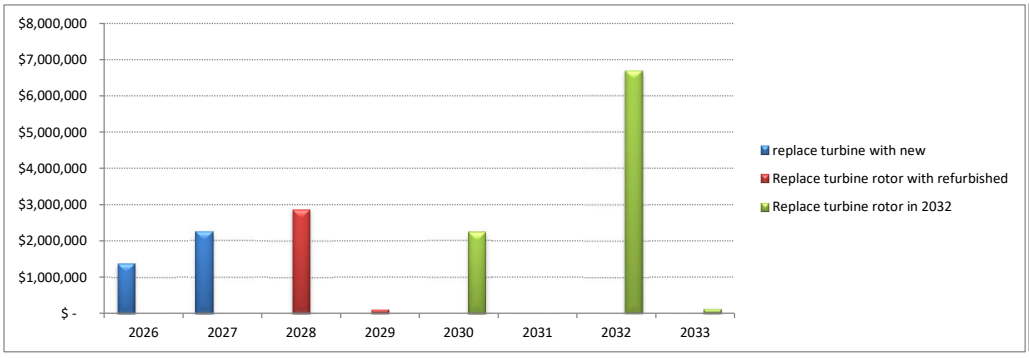
Value Function	Consumers Energy Value Function

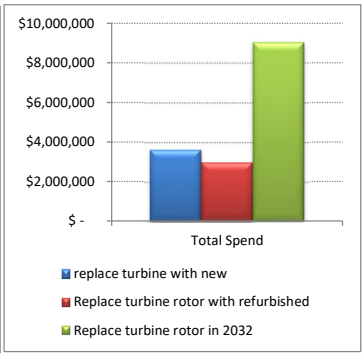
	Assumptions	A new rotor can take up to 14 months to be delivered after order. this would cause a 135-140 MW derate for the site for as long as it takes to get a new rotor. 30% probability of realizing this risk based on uncertainties around new rotor deliveries. This is a conservative estimate. Replacement rotor up to 14 months lead time with a planned order. could be longer if unexpected failure or not planned. Rotor failure could happen any time after reaching rotor life limit. This will be considered high probability after 2032. Replace turbine rotor in 2032 will require an additional Major outage to complete the project. This will incur major costs as the entire plant would have to be shut down for around 4 weeks. 100% probability of realizing this risk if selecting this option. The cost of the risk was calculated using the lost generation risk model and used in this model as an added cost in 2032. The calculated cost is $6,891,000. Unit 7 is expected to be ran as a baseload unit starting sometime 2026. If Unit 7 is separated out as its own node to run baseload, then a refurbished rotor will not have enough hours to make it to 2041. Whereas if the plant continues to operate as is, then a refurbished rotor would have enough hours to make it to 2041. Rotor replacement with a new 7EA rotor. Expected to provide the site with 5,000 starts/128,000 hours of operation Rotor replacement with a refurbished 7EA rotor. Expected to provide the site with 4,500 starts/95,000 hours of operation Installing a new rotor vs a refurbished unit will ensure that the turbine lasts until 2041 considering that unit 7 is now expected to run as a baseload unit which means operating hours will be much higher than current operations. It will be assumed a savings of $2.8M based on current price of $2.1M for a refurbished unit plus inflation costs and additional outage time and resources to execute this project (conservative estimate).
Alternative Details	Replace turbine rotor with refurbished	Rotor replacement with a refurbished 7EA rotor during 2029 major outage ($2.4M Unloaded). Expected to provide the site with 4,500 starts/95,000 hours of operation
	Replace turbine rotor in 2032	Replace turbine rotor in 2032 will require an additional Major outage to complete the project. This will incur major costs as the entire plant would have to be shut down for around 4 weeks.
Alternative Details	replace turbine with new	With there being a possibility of the unit becoming baseload, we didn't want the rotor's life being a factor in derating the plant's output as it gets closer to 2041. We agreed to conservatively go with a new rotor over the refurbished rotor that was in CA and LTFP. This changes the project's (GEN002684/ B-PP-00260) cashflow from needing no money until 2027 to needing funds in 2026 as well as different amounts of money being needed in 2027 and 2028.

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
replace turbine with new	Recommended	$ 3,622,500	1/1/2026
Replace turbine rotor with refurbished	Candidate	$ 2,976,102	1/1/2028
Replace turbine rotor in 2032	Candidate	$ 9,031,139	4/1/2032

Name	Status	2026	2027	2028	2029	2030	2031	2032	2033
replace turbine with new	Recommended	$ 1,380,000	$ 2,242,500	$ -	$ -	$ -	$ -	$ -	$ -
Replace turbine rotor with refurbished	Candidate	$ -	$ -	$ 2,867,290	$ 108,812	$ -	$ -	$ -	$ -
Replace turbine rotor in 2032	Candidate	$ -	$ -	$ -	$ -	$ 2,231,107	$ -	$ 6,685,673	$ 114,359





Forecasts - Draft (replace turbine with new)

Account Type	2026	2027	2028	2029	2030	2031	2032	2033
Capital	$ 1,242,000	$ 2,018,250	$ -	$ -	$ -	$ -	$ -	$ -
Cost Of Removal	$ 138,000	$ 224,250	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002943	**2027**	**4**	**Literal**

Investment Name	Scenario
JGS - Main and Aux Cooling Tower Rebuilds	**Draft**

Value Function	**Consumers Energy Value Function**

Jackson generating Station has a circulating water system that has a single eight-cell induced draft, counterflow cooling tower and an auxiliary cooling water system that has a two-cell induced draft, counterflow cooling tower. Each tower consists of a pressure treated Douglas fir structure with PVC fill and drift eliminators, a fan deck made of pressure treated tongue and groove plywood, cell partitions and windwalls made of pressure treated, Douglas fir plywood, fiberglass reinforced plastic (FRP) pipe headers with PVC lateral distribution systems. The current cooling towers have been in service for 22 years with no planned or major maintenance performed on them in that time. The Douglas fir components are delaminating and deteriorating from the wear and tear of the water and the chemical used in the water.

A complete cooling tower health assessment was performed in Fall 2024. That assessments and their findings were categorized as danger (immediate attention required), warning (short-term repair needed in the next 12-18 months), caution (mid-term repairs needed in the next 2-2½ years or future monitoring), and good (long-term repairs needed > 2½ years or no recommendations). Inspection reports are attached.

Investment Type	Generation	Planning Portfolio	Jackson
Facility	Jackson / Jackson		
Executive Summary	The JGS - Main and Aux Cooling Tower Rebuilds project at the Jackson Generating Station involves significant upgrades to the cooling tower systems, which have been in service for 22 years without major maintenance. The cooling towers, made of pressure-treated Douglas fir, are deteriorating due to water and chemical exposure. Scope of Work The project aims to replace various structural components of the cooling towers, including: 4x4 columns, 2x4 longitudinal and transverse girts, 4x4 diagonal braces, splice blocks, brace straps, and hardware Fill media and supports, drift eliminators, wind and partition firewalls, distribution systems, fan decks, and exterior casings Mechanical equipment like fan cylinders will be reused Objectives Mitigate forced outage risk: Prevent unplanned outages due to structural failures Circulating water pump issues due to delamination of partition walls and structural supports would be a 3-day delay. 560 MW derate each time. These are the most common outages with the highest risk. 10% probability of realizing this risk. Deterioration of structural supports causing a cell to collapse would require a 2-4 month forced outage to recover from due to material lead times and scope of work. This carries a probability of 1.5% and escalates by 25% year over year until 2040. Annualized probability of 10% for modeling. Energy inefficiency: Reduce energy loads caused by longer run cycles Environmental: Prevent the release of untreated water Health: Avoid bacteria like Legionella that can cause Legionnaires' disease Structural damage: Address the deterioration identified in the Fall 2024 inspection Alternatives Considered Recommended: Rebuild using fire retardant polyester resin (FRP) with a draft forecast of $14,649,496 between Jan 2027 and Dec 2030. This material is more resistant to chemicals, moisture, and has a longer lifecycle. Candidate: Rebuild using pressure-treated Douglas Fir #2 (PTF) with a draft forecast of $15,821,001 between Jan 2027 and Dec 2030. This traditional material is initially more cost-effective but requires more maintenance. Risks and Consequences Delamination and deterioration: Can lead to blockages in circulating water pump intakes, causing unplanned outages Structural failure: Could result in a collapse, making the cooling tower unusable and shutting down the plant Environmental compliance: Degradation can lead to violations of the plant's permit with Michigan's Department of Environment, Great Lakes, and Energy (EGLE) Potential capacity losses: Estimated at $21,954,189 in the event of a forced shutdown		
Last Approver		Approval Date	

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Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002943	**2027**	**4**	**Literal**

Investment Name	Scenario
JGS - Main and Aux Cooling Tower Rebuilds	**Draft**

Value Function	**Consumers Energy Value Function**

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 4
	Rate Case Mapping	Gas Generation
	EPM Managed	Yes
	Outage Type	Site
	Scope	Scope of work is to replace the ten cooling tower structures' 4x4 columns, 2x4 longitudinal and transverse girts, 4x4 diagonal braces, splice blocks, brace straps, and hardware. Fill media and fill supports will be replaced. Drift eliminators, drift eliminator supports, and drift eliminator penetration & perimeter seals. Existing wind and partition firewalls will be removed and replaced with single sided ½" plywood wind wall, double sided ½" plywood fire wall, and 2x4 wind & firewall mid-bay supports. Distribution system will be removed and replaced with new headers, laterals, vent pipes, pipe saddles and supports, gaskets and grommets, and distribution nozzles. Fan decks will be removed and replaced. Exterior casings will be removed and replaced. Mechanical Equipment including fan cylinders will be reused.
	Objectives	mitigate forced outage risk Energy inefficiency – Increase energy loads due to longer run cycles to transfer heat from the water cycles. Environmental – Deteriorated cooling tower structures can lead to the release of untreated water onto the grounds surrounding the towers which is reportable to EGLE. Health – Poorly maintained cooling towers can harbor bacteria like Legionella which can cause Legionnaires' disease when airborne droplets are inhaled. Structural damage – The Fall 2024 overall structural health inspection of the main and aux cooling towers identified that the cells need rebuilds to prevent component failures or a collapse of cell(s). Immediate repairs are being performed in 2025 but rebuilds due to age and water related deterioration is needed in the near term to prevent issues that would affect the operation of cells or towers which would impact the plant's dispatchable load capability until corrected.
	Planner Recommended Alternative	Rebuild main and auxiliary cooling towers using fire retardant polyester resin (FRP); $9.551M (unloaded) Initial cost of this option is approximately 7.5% higher the cost of traditional materials like pre-treated Douglas fir which was used in the original construction of JGS cooling towers. The cost has come down considerably over the last 25 years. The material is more resistant to chemicals like those used to treat the plant's water and is unaffected moisture or water. The material has a higher strength than timber and 1¼ times more rigid than timber. The material required less maintenance and has longer product life which contributes to a lower lifecycle cost. The material has high dielectric capability compared to timber which can be conductive when wet. The product's durability, corrosion resistance, and longevity were factors make it more cost effective in the long run than option 2 (pre-treated Douglas Fir). Delamination of partition boards and the deterioration of structural supports leads to them separating from the structure. Partition boards and structural supports then find their way into the circulating water pump suction pits where they can and have blocked circulating water pump intakes/suctions. Such blockages can and have impacted operations to the point of unplanned outages that take the facility offline for 3 days, so the impacted tower is drained, cleaned and refilled. The missing partition boards affect the water flow distribution and leads to cell thermal inefficiency. The higher cooling water temperatures increase the plant's heat rate, meaning more fuel is needed to generate the same amount of power. Missing partition boards from cells provide a path for water to escape the system which is a reportable notice of violation from EGLE. Mitigating measures would need to be put place until an outage as issues arise. In addition to blocking circulating water pump intakes/suctions, the deterioration of the structural supports causes the cooling tower structure to shift, or not properly handling/transferring of loads. The collapse of the structure would be inevitable. This type of failure would make the cooling tower unusable when will shut the plant down until the issue is resolved. Other alternative considered: Rebuild main and auxiliary cooling towers using pressure-treated Douglas Fir #2 (PTF); $8.9M (unloaded) Original construction material for the plant's cooling towers. Traditional material for cooling tower construction. More cost effective initially than rebuilding with fire retardant polyester resin (FRP) but usually requires more O&M maintenance and replacement over the course of the product's life. The material can warp, rot and decay when exposed to moisture, water and chemicals. Cooling towers built from this material have a 25-year service life.

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Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN002943	2027	4	Literal

Investment Name: **JGS - Main and Aux Cooling Tower Rebuilds**

Scenario: **Draft**

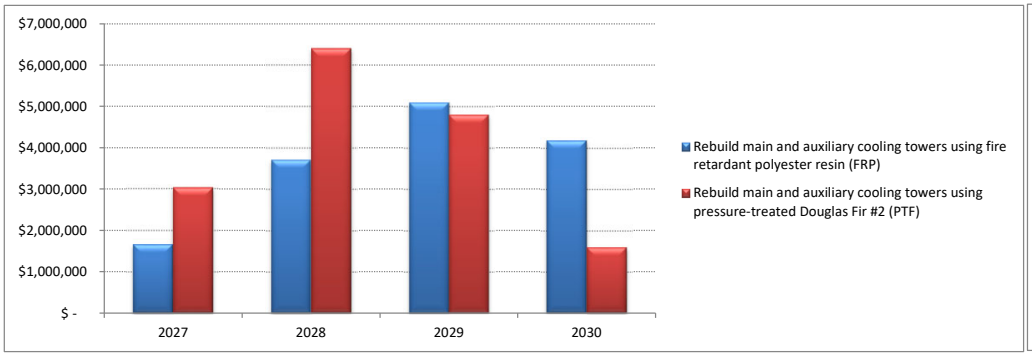
Value Function: **Consumers Energy Value Function**

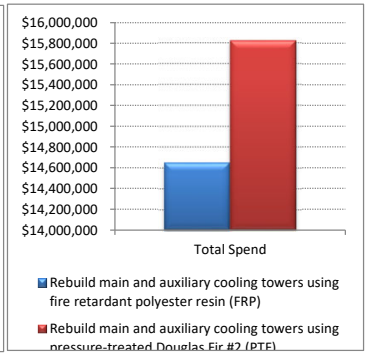
Alternative Details	Assumptions	These rebuilds will be equipment outages. One cell at a time during the shoulder months and plantwide outages. Risk: Delamination of partition walls and deterioration of structural supports will continue. failure history: There have at least two occurrences in the last 5 years associated with cooling tower debris and other debris causing a unit derate to the point where forced outages were taken to clean the circulating water pump intake sump pits. Circulating water pump issues due to delamination of partition walls and structural supports would be a 3-day delay. 560 MW derate each time. These are the most common outages with the highest risk. 10% probability of realizing this risk. Deterioration of structural supports causing a cell to collapse would take two to four months to recover from due to material lead times and scope of work. This carries a probability of 1.5%. Due to the age of the cooling towers and failure history, the probability of failure from the status quo/"do nothing" option will increase 25% on a year-to-year basis because the stage of deterioration of the structural components from water wear and age. Given these factors, the annualized assumed probability of failure will be 10% (assuming end year as 2040). Degradation of the cooling towers can lead to water from the cooling towers to the waterways of the state via the storm drain system which is a violation of the plant's permit with Michigan's Department of Environment, Great Lakes, and Energy (EGLE) which is tied to a National Pollutant Discharge Elimination System (NPDES) wastewater discharge general permit. This permit keeps the plant in compliance with the provisions of the Federal Clean Water Act, 33 U.S.C., Section 1251 et seq., as amended (CWA); Part 31, Water Resources Protection, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (NREPA); Part 41, Sewerage Systems, of the NREPA; and Michigan Executive Order 2019-06. Site has had 2 or 3 events in the last five years, but no notices of violation were issued by the regulatory parties. The basis for notices of violation not being issued was because the plant notified the regulatory parties immediately, the plant's testing after events showed that the tested parameters were not above the stated limits, and the plant instituted corrective measures to prevent reoccurrence. The Environmental Protection Agency (EPA) can impose fines of at least $5,000 and up to $50,000 per day of violation for unauthorized discharges in violation of the plant's NPDES permit. 1% chance of realizing a compliance risk. Potential Capacity losses in the event of force shutdown have been calculated at $21,954,189. The calculations were made using a conservative calculator provided by the capacity forecast team. The CONE value used for this model is $130,930. 75% of CONE was
	Rebuild main and auxiliary cooling towers using fire retardant polyester resin (FRP)	Initial cost of this option is approximately 7.5% higher the cost of traditional materials like pre-treated Douglas fir which was used in the original construction of JGS cooling towers. The cost has come down considerably over the last 25 years. The material is more resistant to chemicals like those used to treat the plant's water and is unaffected moisture or water. The material has a higher strength than timber and 1½ times more rigid than timber. The material required less maintenance and has longer product life which contributes to a lower lifecycle cost. The material has high dielectric capability compared to timber which can be conductive when wet.
	Rebuild main and auxiliary cooling towers using pressure-treated Douglas Fir #2 (PTF)	Original construction material for the plant's cooling towers. Traditional material for cooling tower construction. More cost effective initially than rebuilding with fire retardant polyester resin (FRP) but usually requires more O&M maintenance and replacement over the course of the product's life. The material can warp, rot and decay when exposed to moisture, water and chemicals. Cooling towers built from this material have a 25-year service life.

Alternative Spend Profile

Name	Status	Total Spend	Alternative Start Date
Rebuild main and auxiliary cooling towers using fire retardant polyester resin (FRP)	Recommended	$ 14,649,496	1/1/2027
Rebuild main and auxiliary cooling towers using pressure-treated Douglas Fir #2 (PTF)	Candidate	$ 15,821,002	3/1/2027

Name	Status	2027	2028	2029	2030
Rebuild main and auxiliary cooling towers using fire retardant polyester resin (FRP)	Recommended	$ 1,664,560	$ 3,705,896	$ 5,095,244	$ 4,183,796
Rebuild main and auxiliary cooling towers using pressure-treated Douglas Fir #2 (PTF)	Candidate	$ 3,023,654	$ 6,398,674	$ 4,799,006	$ 1,599,669





Forecasts - Draft (Rebuild main and auxiliary cooling towers using fire retardant polyester resin (FRP))

Account Type	2027	2028	2029	2030
Capital	$ 1,162,586	$ 2,880,349	$ 3,958,775	$ 3,448,584
Cost Of Removal	$ 501,974	$ 825,547	$ 1,136,469	$ 735,213
O&M	$ -	$ -	$ -	$ -

Concept Approval Internal Report	Investment Code	Report Start Year	Number of Years	Currency Scale
	GEN002943	**2027**	**4**	**Literal**
	Investment Name			Scenario
	JGS - Main and Aux Cooling Tower Rebuilds			**Draft**
	Value Function	**Consumers Energy Value Function**		

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Concept Approval

Consumers Energy
Electric Supply
PROJECT INITIATION & CONCEPT APPROVAL
Generation Planning
Capital

Generation Type: Hydro
Site: Ludington
Unit: 1-6
Date Created: 2/23/2022
Proposed Start Implementation Year: 2024
Project Span Whole Years: 6
Project Title: Ludington 1-6 DCS Control Relay Replacement CA

Problem Description (Section 1-Initial Information):

Ludington Pumped Storage (LPS) units are currently controlled and protected by the original (1970's technology) hardwired electromechanical relay control system, going forward referred to as "the system". The system is comprised of relays mainly in the auxiliary relay room and operator control handles located on the Main Control Board (MCB). The system has outlived its useful life and is failing. The system is not fail-safe in design; does not provide fault tolerance; and the redundancy is inadequate. There are gaps in the system protection scheme. The system is presenting plant operations and maintenance with problems. The Uninterruptable Power Supply (UPS) system is not currently segregated by unit pairs and presents a common point of failure for the plant.

The system is based on electromechanical devices (relays and operator control handles) that wear and have become less reliable over time. The relay contacts wear, and increased resistance has caused intermittent failures. The operator control handles are in a similar state of wear and age and have also experienced intermittent failures. The system will not last until End of Life (EOL) of the units.

The plant was designed using the control and protection methodologies available in the 1970's. Many of the relays in the system fail to a non-protective state. A small subset of examples is as follow:

Emergency Stop Relays (5E) – Each unit has an emergency stop relay. The relay is configured to energize to trip. A failure of this relay results in the unit not being shut down by the relay. There are fourteen legs in the design which energize this relay to trip the unit. A few of them are as follow:

- Turbine Overspeed (125%)
- 345 KV Bus Fault while pumping
- Upper reservoir water level high (Overtopping protection)
- Intake gate closed

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Many portions of the protective scheme are not fault tolerant. Fault tolerance refers to the ability of a system to continue operating without interruption when one or more of its components fail. As an example, master shutdown relays (5) do not provide fault tolerance. While there are five master shutdown relays for each unit they are not implemented in a redundant fashion. There are five of these relays because when the emergency shutdown function is asked for by the protection scheme there are so many different actions taken that one relay cannot implement them all. Thus, each of the five relays shut down different portions of the process. A failure of any one of the relays will directly affect only the portions of the process tied to that relay. This means that a portion of the equipment (a subset) can inadvertently be tripped while the balance remains in service.

Many critical trip inputs from the relays are not redundant. Redundancy is a system design principle that introduces duplicate components to provide fault tolerance. When a component fails, a backup takes over to ensure the system still performs as designed. A small subset of examples where we rely on one device to provide unit protections is as follow:

- Overspeed switch and aux relay (12X) – One relay contact energizes the emergency stop relay. If the relay fails, we will not shut the unit down as prescribed.
- High draft tube water level (71DWHX) – One relay contact energizes the emergency stop relay. If the relay fails, we will not shut the unit down as prescribed.
- Governor oil tank level low (71GTL) – One relay contact energizes the emergency stop relay. If the relay fails, we will not shut the unit down as prescribed.

Challenges for plant Operations and Maintenance

- The main control board switches are wearing. Even with lubrication and maintenance a number of these switches have the interface with their key or handle worn excessively. Many of our larger main control board switches are no longer in production. There are minimal spares available. Replacement for the more complex switches that have many contacts are no longer readily available and obsolete. We are reliant on custom assemblies for replacements and must commission custom builds. These custom builds also present a problem in long lead times. If failure is observed unit(s) and portions of the plant may remain out of service for extended durations

- The Relay Room is so densely populated with relays that just walking around has caused issues when relays get bumped. As part of the process of routine relays checks the covers are removed and replaced which has caused inadvertent circuit changes.

- Changing a relay(s) can affect multiple circuits and even other units (starting bus, Main Transformer Banks (MTB)) due to their common neutrals. Direct Current (DC) bus grounds can be difficult to find when there is no indication on cause (i.e., alarming).

- Intermittent issues can take months to find and correct. This is due to the lack of active monitoring/measurement that allows for troubleshooting to be performed timely. For each occurrence custom recordings must be setup with ad-hoc hardware to assess what the controls are executing and experiencing.

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- The system does not provide the proper diagnostic and troubleshooting capabilities.

- During the startup and shutdown process plant operations cannot see the operational state of the unit. Functionality and troubleshooting during start/stop sequences cannot be observed other than by individually observing and testing scenarios with personnel and recording devices (multimeters or digital recorders for electrical signals).

- Start permissives have limited visibility. Critical valve positions are not individually observable as they come to single relay collectively to provide the start permissive. Troubleshooting requires additional effort and resources.

- Several current manual processes cannot be automated preventing the removal of human error potential during startup, shutdown, and other equipment configurations.

- Any updates of equipment and systems that need to be integrated with the unit operation are difficult and expensive to integrate into the hardwired relay logic.

- Automation efforts prove to be difficult if at all even possible with the hardwired relay logic. Changes to operating criteria are difficult to implement, test and verify and costly and time-consuming.

- Training for Operations is limited to studying procedures as the system does not provide a testing and simulation environment.

- The unit overtopping protection needs improvements that can't easily, and cost efficiently be implemented into the current legacy relay-based control system (pump start lockout above 932’ reservoir elevation, overtopping protection and system control of how many units are allowed to pump above 940’ and 941’ respectively).

As a result of the system failing the unit can come off-line, become unavailable, or experience derates. In addition, as these devices also serve to provide equipment protection their failure can result in significant equipment damage up to and including destroying significant parts of the unit and/or plant potentially rendering the unit(s) and/or the entire plant unavailable for years. The potential costs of such repairs could easily rise to hundreds of millions of dollars. In addition, there are significant gaps in the original protection design. Consumers Energy is exposed to substantial risk due to the state of the system.

LPS will become more important to the stability of the grid as renewable generation (solar and wind) sources increase and as fossil generation (gas and coal) is decommissioned. LPS provides the Midcontinent Independent System Operator (MISO) grid support by delivering frequency and voltage support (reactive load generation) that replaces the support that will be lost when our gas and coal units are decommissioned. Providing grid stability in conjunction to our generation realignment is an important aspect to our corporate strategy.

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Alternative Solutions/Alternatives Considered

Alternative Solutions (Section 2):

Alternative #1 - Do nothing (20-Year Payback)

Total Cost of doing nothing: $29.6M (51% dollars)

The costs associated with doing nothing include costs associated with the damage occurring as a result of system failure(s) and the units not being available to run and support our renewable strategy. There are other costs related to doing nothing such as maintaining the plant and operational issues that can make the units unavailable for relatively short periods of time, however the major impacts are derived from system vulnerabilities with respect to their protection functions.

DAMAGE
The system provides the basis for personal and equipment protection. If we do nothing, we will continue to experience failures of the system. The frequency of errors is progressively getting worse as system components continue to age. Eventually a failure or combination of failures could result in catastrophic damage to a unit or the entire plant rending it unavailable for up to a year or more. This would cause significant impacts to our ability to serve our customers.

Relay fault probability used is based on data from the Overtopping Fault Tree analysis report. In the report the Savanna component fault probability database was consulted, and the component fault relay probability used as part of the overtopping fault tree analysis was 0.001 failures per day.

ALREADY OCCURED
Recently the plant experienced an incident where unit 4 entered shutdown as it went into pumping mode before the generator breaker was closed and the unit synchronized. As mentioned in the problem statement there are gaps in the logic, a pumping mode should not be permitted until unit 4 had been synchronized. In addition, as part of the event the cross trip to unit 1 did not take place and the unit 4 motor was operated synchronously (as its exciter had been taken offline when unit 4 went into shutdown). Damage to the unit 4 generator field along with other equipment may/could have occurred. The plant is still looking into the incident; however, it is difficult to ascertain what truly happened with the current system in that the protections are not all contained in one system. Portions of the protection are in the system relays and portions are in the protection relays. This event is indicative of the system risks. Damages for this event can easily reach $60M and make a unit unavailable for months which would cost another $15M depending on Local Marginal Price (LMP) and market demands. The total cost for an event of this nature could reach $75M (100% dollars).

POTENTIAL EVENTS
The following provides a description of three other scenarios that provide significant system failure(s) risk to the operation using the old technology. The three scenarios below are a small subset of the control system vulnerabilities. It should be noted that these are all low probability

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and high cost/consequence events. Based on data from the Overtopping Fault Tree analysis report the fault probability database was consulted and the relay fault probability of 0.001 failures per day was used.

Scenario 1: Turbine Overspeed Switch and Aux Relay (12X)
The system provides unit overspeed protection through a relay which is energized to trip. If the relay fails when needed during an overspeed event the damage associated with an overspeed event could be to damage the rotor bearings and the rotor itself. This would make the unit unavailable for years of time and costly repairs. It is estimated the repair cost could reach up to $160M and the loss of the unit for years another $70M for a total of $230M. Based on data from the Overtopping Fault Tree analysis report the fault probability database was consulted and the fault probability of a relay is 0.001 failures per day; the fault probability of the wicket gates failing to close is 0.0002 per day. This results in a total probability of failure of 2E-7 per day, which is 7.3E-5 per year.

7.3 E-5 x $230M = $16,790/year x 20 years = $336K x 6 units = $2M (100% dollars)

Scenario 2: Upper Reservoir Water Level High (Overtopping Protection)
As a FERC regulated facility, dam safety is of the utmost importance. Consumers Energy is under constant scrutiny by regulators to provide safe reliable operations. Overtopping protection is very high on the priority list. Proving the effectiveness and reliability of dam safety protection schemes for overtopping protection is a must do. The overtopping protection protects corporate and public, life and property. The current plant overtopping protection scheme has 4 levels of protection. A breach of the overtopping protection schemes would require disclosure to our regulators which could trigger a requirement to install an emergency spillway, which may cost in excess of $150M (100% dollars).

No cost with regard to this scenario has been placed into the cost of this solution as the probability is negligible, however this scenario demonstrates the magnitude of cost were the event to occur.

Scenario 3: Loss of the starting bus
As the system provides protection for the plant starting bus, a failure in its protection would leave the plant without many if not all of its units for years depending on the severity of the event. This estimate uses a loss of three units for 1 year It is estimated that the replacement of the starting bus would cost around $100M and losses in revenue of $25M (100% dollars).

No cost with regard to this scenario has been placed into the cost of this solution as the probability is negligible, however this scenario demonstrates the magnitude of cost were the event to occur.

HIGHER FUTURE PROJECT INTEGRATION COSTS
There are many projects being executed at the plant. The costs for these projects to integrate with the system is higher and costs projects an additional $70,000 per year. In total that amounts to $1.4M over the 20-year payback period.

The cost for the 20-year payback period is $1.4M (100% dollars) or $.7M (51% dollars).

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PLANT OPERATION AND MAINTENENCE COSTS

The operation and maintenance costs of maintaining and working with the system are estimated to be $100,000 per year per unit. This includes but is not limited to the extra time it takes to troubleshoot issues; the cost to maintain the system as best as possible; and the extra overhead related to operations. Over the period of 20 years the total is $12M (100% dollars).

The cost for the 20-year payback period is $12M (100% dollars) or $6.1M (51% dollars).

FORCED OUTAGES

Increased Random Outage Rates (ROR) due to continued failures of the system may cause unit outages and/or derates.

Using NERC Generating Availability Data System (GADS) data and supplemental knowledge of plant management that the units are worth $5M – $6M in the high season (July – September) and the expected forced outages based on past events it is estimated that there will be revenue loss of $1.75M (100% dollars) in the future year. It was then assumed that there will be a rise in forced outages due to the relays at the rate of approximately 3% per year. Projecting this out over a 20-year timeframe (the period that choice 2 & 3 would be expected to be in service before further action) would result in a cost of $42.9M in lost revenue.

Total cost breaks down for the 20-year payback period to:

Damage:	$2M (100% dollars) or $1M (51% dollars)
Project Integration:	$1.4M (100% dollars) or $.7M (51% dollars)
Operation & Maintenance:	$12M (100% dollars) or $6.1M (51% dollars)
Forced Outages:	$42.9M (100% dollars) or $21.8M (51% dollars)

The cost for the 20-year payback period is $29.6M (51% dollars).

Alternative #2 - Replace hardwire relay control system with Distributed Control System (DCS) and segregate the UPS (20-year payback)

Total cost of putting in a DCS: $13.4M (51%dollars)

Installing a modern Distributed Control System (DCS) will allow a system that will be able to be used and maintained for the life of the unit. It will increase site availability by reducing failures caused by aging relays and allowing better diagnostic tools such as historian trends, live logic viewing, alarm messages and related operator responses, and common Human-Machine Interface (HMI) control for all the plant equipment in a central system. A modern control system also allows for additional process automation further reducing error potential during operations and associated impacts.

The DCS Control Relay Replacement Study project (PH-20106) evaluated the detailed scope, budget, and schedule to replace the existing hardwired controls at the Ludington Pumped Storage (LPS) facility with full Emerson Ovation Distributed Control System (DCS) control. The study included the following scope:

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Modernization of the control room including removal of many of the operator control handles on the Main Control Board (MCB) to be implemented in the DCS as well as optimization of the layout of the control board for operational efficiency. In addition, the operator control console would be replaced with a modernized console with dedicated alarm displays and alarm response aids. The central alarming function the DCS provides enhances reliability of the units. As an example, DC bus grounds will be brought into the DCS for diagnostic and troubleshooting purposes.

A high fidelity DCS simulator will be provided for the project. The simulator will provide operator training capabilities prior to implementation of DCS control and monitoring at the plant. The simulator will be capable of replicating all logic and control schemes for all six (6) units. The simulator will allow testing of logic changes before they are implemented on the "actual" units which will enhance reliability. Simulation will be a primary means to test and verify logic operation before the implementation outages for each unit. This will help reduce risks during this project.

Turbine Supervisory Panels - Remote control functions associated with the turbine datalink will be migrated to hardwired DCS control as part of this project to replicate the existing plant hardwired controls from the MCB panels.

Pony motor control and monitoring will be migrated to the DCS.

The existing UPS system at the plant has a rating of 20KVA and provides 120VAC power to equipment for all six (6) units. This UPS system has reached its maximum capacity and requires an upgrade to support future loading requirements. The new DCS hardware installed as part of this project requires reliable and redundant power distribution for plant operations. An evaluation of the UPS system was performed. The results determined that a full upgrade of the UPS system is required to support the project and maintain sufficient spare capacity for future projects. Three (3) separate 20KVA UPS systems will be installed to allow unit pair separation (Unit 1 & 2, Unit 3 & 4, and Unit 5 & 6) to provide reliable and redundant power distribution throughout the plant.

The cost for the 20-year payback period is $13.4M (51% dollars)

Alternative #3 - Replace all Control Relays and a portion of the operator control handles with new ones and replace and segregate UPS (20-year payback)

Total cost of replacing the relays: $22.7M (51% dollars)

A complete replacement of all control relays to reach end-of-life (EOL) of the plant would require an immense undertaking to de-terminate the wiring on close to a thousand relays, replace the relay and rewire to the previous state. The system would require a complete recommissioning of the control system and post maintenance testing. Validity of the testing would be difficult. The amount of time required to do this work would require the work to be performed over multiple outages and would be difficult to perform without complete site outages. There would be increased risk of possible unit trips if attempted to perform under individual unit outages due to common systems and interrelated control signals.

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This option does not provide benefits to resolve all the issues mentioned in the problem definition. Trouble shooting issues are still limited by the lack of tools available as compared to a modern control system. Many of the problems that occur over time are the result of the system itself being comprised of hundreds of electro-mechanical relays that eventually wear out and fail. Common operator interface of a DCS, along with operating events and alarms brought into a system-wide historian and allowing full historic trending of the process leading up to the issue, is not available with the relay-based control system.

The cost of replacing the relays will also include the following costs as they are not mitigated by the solution as in reality there is no alternative that will do what a DCS does. The following items are detailed in the cost of doing nothing choice and have been scaled as to their associated costs with this choice.

Damage:	$2M (100% dollars) or $1M (51% dollars)	(Scale Factor 1)
Project Integration:	$1.4M (100% dollars) or $.7M (51% dollars)	(Scale Factor 1)
Operation & Maintenance:	$10.8M (100% dollars) or $5.5M (51% dollars)	(Scale Factor .9)
Forced Outages:	$21.5M (100% dollars) or $10.9M (51% dollars)	(Scale Factor .5)
Cost to replace relays:	$9.0M (100% dollars) or $4.6M (51% dollars)	(Scale Factor 1)

The cost for the 20-year payback period is $22.7M (51% dollars).

Recommended Alternative Benefits/Objectives (Section 3):

Recommended Alternative #: 2
Recommended Alternative: Replace hardwire relay control system with Distributed Control System (DCS)

Why was this Alternative chosen?

A DCS is recommended for full control of the units at Ludington Pumped Storage. This solution provides a reliable and sustainable method to control and operate the six units at LPS for the remainder of the life of the plant. The DCS solution mitigates gaps in the plant protection scheme. The DCS solution will therefore mitigate the potential of damage at the plant. The DCS will make integration with future projects less expensive. The DCS will reduce the plant operation and maintenance costs.

The architecture of a DCS allows the reduction of electromechanical relays and timers and replacement with electronic input/output (I/O) modules that do not rely on mechanical movements and physical contacts to control the equipment. The DCS can program the sequencing of the equipment using control logic sheets (SAMA - (Scientific Apparatus Makers Association) control functional diagrams) that represents the functionality of hardwired series and parallel relay circuits. The number of physical components that can fail is significantly reduced. Operation sequences can be changed and updated with greater ease and new equipment can be added to the DCS control with less effort and full integration into the system. A DCS also provides appropriate control and trip redundancy that currently does not exist.

The modern DCS provides a complete control solution. HMI graphics provide the operator with easy to use "mouse-click" control of the plant equipment. Process sequences can be automatically

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controlled to reduce and eliminate operator intervention. Troubleshooting tools such as live logic display, trending and historical review, and alarm with alarm responses improve the diagnostic capabilities and reduces the time required to resolve problems. The DCS can also improve efficiencies and performance by providing more accurate control and monitoring of equipment and processes. Integration of other equipment control systems can be brought into the DCS to provide a single user interface for the operators to monitor and control all equipment with a common alarm system.

There have been several engineering studies performed in the last 15 years to determine the best options for the extended operating life of Ludington Pumped Storage Facility. In 2007 a study was prepared by Devine Tarbell & Associates, Inc. (DTA) (DTA was acquired by HDR in 2009). The study was a condition assessment and life extension study along with a technology upgrade study report.

In 2019-2021 the Data Acquisition System was upgraded to Ovation DCS, also annunciator panels and the sequence of events (SOE) recorder were implemented into the DCS. These upgrades were implemented in three projects which resulted in a fully functional DCS (no equipment control) at the plant.

The recommended project is the natural next step in the migration to full control in the DCS.

Another engineering study was performed in 2021 and established a detailed scope, schedule, and budget to execute a project to expand the DCS to fully control the plant.

Project Benefits/Objectives

- Reduce the risk of potential damage due to the state of the current system.
- Replacement and elimination of worn and less reliable control relays and control board switches with new electronic input/output modules and new relays where needed.
- Future projects that have controls impact at Ludington will cost less
- The number of hardware control relays will be reduced due to the "control" being performed in logic instead of "hardwired" circuits. This will increase reliability and reduce outages and derates.
- Common control and monitoring of system equipment allows operation of the equipment from the HMI graphics and keeps the operator focused on one system instead of monitoring several the systems from several areas of the control room on different devices.
- Alarms are located in one alarm system with alarm management and responses based on International Society of Automation (ISA) 18.2 standards. Integration of external systems will be brought into the DCS for common operator experience.
- Automation of sequences can be programmed to reduce operator interface and improve on efficiency and performance of unit operation.
- Operational efficiencies and performance increases may be achieved by modern process control loops with Proportional Integral Derivative (PID) algorithms.
- Diagnostic and troubleshooting capabilities are greatly enhanced with the use of real-time control logic viewing, historian archive capability of process variables and operating parameters, trending graphs of process variables, start permissives, and logging of system messages.

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- Additional redundancy for critical trip controls for reservoir overtopping and equipment protections.
- A DCS will provide the long-term path to support the LPS units into the future and through operation towards their End-of-Life (EOL) dates.

Scope of Work

An engineering study was performed in 2021 to provide a detailed scope of work, schedule and budget to complete this project. The document was completed by Worley Energy and lists the scope in detail for the following items: Please refer to the attached engineering study for full details.

- Control Room -Consoles
- Control Room - MCB Panels (move existing Main Control Board devices to DCS graphics control and monitoring)
- Auxiliary Relay Room (relays replaced with DCS controller drops and I/O modules)
- UPS (Uninterruptible Power Supply replacement and reconfiguration for better redundancy and duration and backup of control systems)

Systems included:

- Creep Detector and Brake Control
- Depression Air Compressors 1 and 2 (common to all six (6) units)
- Electrical System (Unit 1 and Unit 2 common electrical equipment listed below, Unit 3 & 4 and Unit 5 & 6 are similar)
    - Station Power Transformer 1 4KV Breaker 1136
    - 4KV Bus No. 1 to Transfer Bus Tie Breaker 1135
    - 4KV Bus No. 1 to Station Power Transformer 11 Breaker 1199
    - 4KV Switchgear 1 Monitoring
    - 4KV Intake Breaker Feeder 1
    - Station Power Transformer 11 to 480V Bus No. 11 Breaker 1166
    - 480V Bus No. 11 Tie Breaker 1165
    - 480V Bus No. 11 Tie Breaker 1160
    - Standby Transformer No. 10 Breaker 1066
    - Generate/Pump Breaker 116
- Exciter
- Generator Motor Heater
- Governor Cabinet Interface
- HP Oil Pumps
- Intake Gate
- Load Break Switches
    - Load Break Switch 115
    - Load Break Switch 116
- Lockout & Protection Relays
- Miscellaneous Solenoid Control
- MT-1 Transformer (common between Unit 1 & 2, Unit 3 & 4 and Unit 5 & 6 are similar)
- Pony Motor (only applicable for Unit 1 and Unit 6)
- Steering Logic
    - All field inputs interfacing with existing control relays in the MCB and Auxiliary Relay Panels
- Water Depression

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- Engineering and Design and drawings
- DCS hardware, software and logic and engineering and commissioning
- Data links
- Hardwired cable and conduit design, installation, and commissioning
- Integration with current and future projects
- Updating/writing of operation procedures, alarm responses, job aids
- Schedule to be completed over a six-year time period coordinating with unit outages and other project scopes.

Future adaptability and control enhancements or changes are more readily implemented and in shorter time reducing additional future risk. Needs for control enhancements are expected based on lessons learned from events that occur and a needed change to the control logic (= standard work)

Project Justification (Section 4):

Priority Code Title: Critical Projects
Rank: 06
Definition: These projects, if deferred will have a high likelihood of significantly impacting asset reliability in the near term. This category also includes spending to address long-standing safety issues and regulatory commitments that have some flexibility with respect to implementation.

Basis Explanation:

This project removes substantial financial and reputational risks and will save the company money. It addresses the multiple issues presented in the problem description. The presented option provides the highest economical long-term benefit.

Economic Benefit Evaluation (Section 5):

X	**ROR Reduction:**	GADS historic data results can be very subjective on outage and derates with estimates of having a DCS and the amount of time to diagnose and repair the issues (along with the number of units the issue may affect). Estimate 0.3% ROR Reduction.
	O&M and/or PSCR Cost Changes:	
	Changes in Periodic Factor	
	Heat Rate Improvements	

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	Economics - Parameters for IRR Calculation	
	Other:	Reduction in O&M cost due to troubleshooting issues caused by hardwired relay failures and quicker repair and recover with a DCS will decrease resources and duration cause by the existing system components. This will provide more energy value for our customers in added unit availability and power production from our asset(s). The DCS will reduce risks and provide additional protection for dam safety through improved overtopping protection. This DCS project will provide added equipment protection against severe equipment failures.

Funding and Timing (Section 6):

Identify funding that has already been spent or committed, if any: $82,620.
Timing Impact – Is an outage required? YES
Estimated Outage Duration in Days: 120
Desired implementation year: 2023
Outage Type: Unit

Specify the impact if the recommended implementation year is changed:
Outages would be over a rolling 3-year period during the execution phases with approx. 120-day outage/two units each year and complete site outage of 30 days each year. The project would begin in 2023 and 2024 with engineering and planning. Execution of outages to install equipment would begin in 2025 with units 1&2, 2026 for units 3&4, and 2027 for units 3&4. 2028 would include project closeout.
An engineering study was performed in 2021/2022 to develop a detailed scope, schedule, and budget costing $82,620 (51% dollars).

System Engineer: Kevin A. Ortner

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Conceptual Estimate (Section 7):

Year	Loaded Cost (51% dollars)	Description	Total Project Cost (CE & DTE)
2023	$1,000,000	Engineering and Design for Units 1 and 2. Total project cost is $1,960,784.00, loaded cost is CE 51% share.	$1,960,784
2024	$2,106,300	Engineering and Design for Units 1 and 2. Total project cost is $4,130,000.00, loaded cost is CE 51% share.	$4,130,000
2025	$3,763,290	Engineering and Design for Units 3 and 4 and execution of project for units 1 and 2. Total project cost is $7,379,000.00, loaded cost is CE 51% share.	$7,379,000
2026	$3,855,090	Engineering and Design for Units 5 and 6 and execution of project for units 3 and 4. Total project cost is $7,559,000.00, loaded cost is CE 51% share.	$7,559,000
2027	$2,351,100	Execution of project for units 5 and 6 and project close out. Total project cost is$4,610,000.00, loaded cost is CE 51% share.	$4,610,000
2028	$250,000	Project closeout. Total project cost is $490,196.00, loaded cost is CE 51% share.	$490,196
	$13,408,400	Total project cost	$26,290,980

Total Cost: $ 13,408,400

Asset Strategy IRR & Justification

IRR:
Justification:
A/S recommends approval of this project based on obsolete equipment and no parts available for old control system. Due to the new license, we need a control system that will last the remainder of the life of the unit and this DCS system will meet those requirements.

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Approvals:

Concept Approval List

Present Need: On approval, this document authorizes the Generation Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization. EPM will begin work on this project when a completed and approved charter is in place.

Title	Approver	Approval Limit	Signature	Date
Generation Planning Supervisor	George McKenzie	$100K	DocuSigned by: George L. Mckenzie II F35F930DD948493...	4/19/2023 | 1:15 PM EDT
Director of Generation Planning	David Thornock	$250K	DocuSigned by: David E Thornock 31C4AFE905164D3...	4/19/2023 | 2:50 PM EDT
Director of Generation Asset Strategy	Scott Hugo	$250K	DocuSigned by: Scott A Hugo 7743CD0EABA24C0...	4/26/2023 | 9:46 AM EDT
Exec Director of Electric Supply Engineering	Richard Blumenstock	$2M	DocuSigned by: Richard Blumenstock C3E2F0B9920949B...	4/26/2023 | 5:26 PM EDT
VP of Electric Supply	Timothy Sparks	$5M	DocuSigned by: Timothy J Sparks 8916E70683B04D6...	5/1/2023 | 7:45 AM EDT
SVP of Transformation and ENG	Tonya Berry	$20M	DocuSigned by: Tonya L Berry BEAA3C1321D54C4...	5/1/2023 | 8:28 AM EDT

EXHIBIT A-229 (MEW-36)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-230 (MEW-37)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

Case No.: U-22070
Exhibit No.: A-231 (MEW-38)
Page: 1 of 12
Witness: MEWittbrodt
Date: June 2026

LPS Admin Space Replacement

One Electric Supply

Jan 21, 2026

Consumers Energy
Count on Us®

LPS Admin Space Replacement

Problem Description: The temporary administrative trailers have exceeded their service life and are now in poor condition. The current design has inefficiencies and safety impacts that affect daily operations and outage execution.

Key Objective: Create a long-term, cost-efficient replacement for the aging administrative facilities by delivering a safe and consolidated workspace that strengthens operational effectiveness and supports all project and plant personnel for the next 45+ years.

Options considered:

1) Do Nothing
2) Replace trailers with like in kind trailers
3) Replace trailer(s) with a permanent structure

Risks:

- Options 2&3 are not in the 2026 rate case.
  - Option 3 has been in the LTFP for the past 5 years with a 2028 execution date (need to accelerate)
    - Copperleaf value model shows that the permanent building is the best decision
      - (Risk mitigation – A strong business case leads to positive outcome on rates reconciliation)

LPS Admin Key Notes

Factors supporting:

- Favorable litigation outcome ($464M + Fees)
- Aligned with DTE

Funding Needs: ($8.9M in 51% dollars) Reduced original scope by $5M

- 2026 = $4.9M
- 2027 = $4.0M

Funding Strategy:

- 2026 - $4.4M would be funded from the ($10M Elec Supply Checkbook) + Project team would fund $0.5M
- 2027 - $3.0M would be funded in LTFP by Electric Supply + Project team would fund $1M

Note: This strategy will not impact any critical site or EPM project funding

Funding/Schedule Risk

Funding Risks: (at 60% Design)

- 2026 = $4.9M
- 2027 = $4.0M

-10% to +25% ($8M-$11.1M)

Value Engineering (VE) to mitigate risks and drive costs down

Schedule Risk/Opportunity

Key Opportunity / Risk	Prob / Impact	Mitigation	Status
Opportunities			
Early Contractor Procurement at 60% Design	High/ Saves 4 to 6 months	Working with Supply Chain to prepare request for proposal for construction manager at risk using major construction contract by February to have contractor on board in March of 2026. Early procurement of contractor assists with value engineering and long lead procurement of materials and building permits.	Discussions initiated with supply chain.
Risks			
Environmental Permitting			
1) Joint Permit Application	Low/ 9 to 12 months	Ensure all work remains above the ordinary high water mark and no permit required.	Reviewed with Environmental
2) National Pollutant Discharge Elimination System (NPDES) permit	High/ 30 to 60 days	Submit renewal application by April 2026 with the revision to relocate one stormwater outfall. No added storm water outfalls. If submitted by April will not affect start of construction in May .	Underway with Environmental
3) Soil Erosion Permit	High/ 30 days	Contractor to submit with final soil erosion design documents. Submit in April 2026 to start work in May.	
FERC Notification	High/60 Days	Site will notify FERC upon Design completion. Submit in March 2026.	
Building Permits	High/30 to 45 days	Contractor to secure with completed designs. To submit by the first of April 2026	
Long Lead Precast Concrete structural components	High/ 20 weeks	As soon as Contractor is under contract the contractor will start procurement with supplier in March 2026	
Delayed occupancy	Low/8 weeks	Site has plan to have personnel grouped into alternate available trailer spaces by area/project of focus to support work and critical communication	

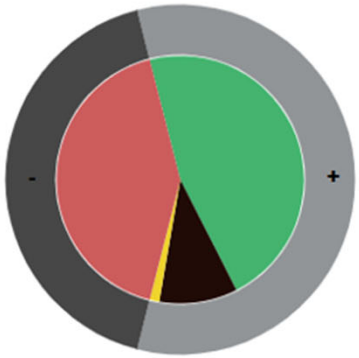
Conclusion

- Now is the optimal time to execute
  - Major work start is anticipated mid 2027
- Cost risks can be managed and maintained within approved rate case targets
- Schedule risks to be managed by EPM Facilities and Operations.
  - Contingency plan ready if the permanent structure is unavailable for occupancy by start of major work
- Solid business case supports the permanent building and positive outcome for rate reconciliation
- We are seeking a move forward recommendation

Copperleaf Value Model – Option 2&3 Comparison

Option 3: New building – Positive NPV of $3,151k

Draft Investment Value
LPS Admin office addition



Value Measure	Value
Cost Avoidance - O&M	9,203
Financial Benefits - O&M	2,025
Employee Productivity	247
Cost Avoidance - Capital	0
Financial Benefits - Capital	0
Revenue Increase	0
Total Investment Cost	-8,324
Total	**3,151**

Option 2: Replace trailers every 15 years – NPV of $2,196k



Value Measure	Value
Cost Avoidance - O&M	9,203
Employee Productivity	0
Cost Avoidance - Capital	0
Financial Benefits - Capital	0
Revenue Increase	0
Financial Benefits - O&M	-2,325
Total Investment Cost	-4,681
Total	**2,196**

LPS Admin Summary

Options considered:

1) Do Nothing

2) Replace the temporary trailers with like in kind

Challenges:

- Aging Facilities: The current administration building is at capacity with no additional space available for additional occupancy. The temporary trailers are deteriorating and are reaching the end of useful life and will become uninhabitable. Most trailers are at or beyond their accepted 15 year lifespan.

- Space: The existing facilities cannot accommodate the increased Operations, Engineering, and Project personnel required for outage, project planning and execution with the approaching major outages through 2030 and beyond.

- Operational Inefficiencies: The fragmented office spaces silos, hinders efficient communication and complicates coordination for safety and critical site events.

- Technical support: Additional groups often visit the site for outage support, studies, planning, etc. These individuals also need accommodations the current space is challenged to provide.

- Maintenance Burden: Trailers require constant maintenance—16 HVAC units, plumbing, and electrical systems all designed for temporary systems resulting in high annual repair costs and inefficiencies.

- Gaps to accepted standard(s): The facilities have an insufficient restroom capacity well under acceptable standard. The largest conference room has insufficient size and capacity for site-wide and high-attendance meetings forcing staff into standing-room-only conditions outside of the room creating egress hazards and inefficient communication

LPS Admin Summary

Options considered:

3) Replace trailer(s) with a permanent structure

NOTE: Through value engineering and scope reduction we have reduced the overall costs by $5M

Benefits

- Lifecycle Advantage: Permanent structure avoids repeated trailer replacements, impacts of those replacements over time, impacts to business continuity during those replacement and associated costs
- Consolidated Office Space: Supports all Consumers Energy and DTE staff (Operations, Maintenance, Engineering and Project) with organized work areas under one roof.
- Improved Safety and Collaboration: Eliminates communications silos and enhances safety through significant reduction in foot traffic across areas of the site and adjacent to vehicle traffic areas of the site (high energy) also reducing risk of slippery surface incidents during unfavorable weather.
- Corrected Auditorium (Largest Conference Room) Capacity: Largest room for site-wide meetings and outage planning is designed to accept up to 50 people.
- Reduced Maintenance Costs: Single building built to a higher standard versus maintaining multiple temporary trailers with temporary service equipment (design of HVAC, lighting, restrooms, etc).
- Efficient Infrastructure: Central IT room, compliant restroom facilities, and shared kitchen spaces.

Copperleaf value model assumptions and benefits

Model Assumptions Driving Value

Trailer Replacement Cost: In-kind trailers require a **$4M replacement cycle every ~15 years**, totaling **$16M** through 2069 + decommissioning. (4 replacement cycles)

Recurring O&M Costs: Trailers require **$30k/year** in HVAC/roof/plumbing/electrical repairs and **$5k/year** for portable restrooms.

Displacement-Driven Mileage: Continuing with trailers forces displaced staff to commute from Lakeshore, adding **$100k/year** in mileage costs.

Operational Inefficiencies: Fragmented temporary structures create measurable productivity losses and hinder coordination during critical site activities.

Cost Comparison

In-Kind Trailers: $16.1M lifetime + **$30k/year** repairs + **$100k/year** added O&M

New Building: $8.9M upfront, lowest lifecycle cost and risk

Benefits of New Building

Major Cost Savings: Avoids $16M–$22M in long-term trailer replacement costs and eliminates $135k/year in recurring trailer-related O&M (repairs, restrooms, and displacement mileage).

Lowest Lifecycle Cost: A single $8.9M investment replaces four trailer cycles, reduces maintenance burden, and stabilizes long-term capital planning.

Consolidated Workspace: One secure, modern facility for all site staff, eliminating the inefficiencies of five separate trailers.

Improved Collaboration & Safety: Centralized teams enhance communication, outage coordination, and safety oversight.

Modern Meeting Capacity: Large conference rooms support site-wide briefings, outage planning, and contractor management.

Efficient Infrastructure: Central IT room, compliant restrooms, shared kitchen, and reliable utilities reduce operational friction.

Visitor-Ready: Adequate space for tours, training, and safety briefings, improving stakeholder engagement.

Replace failing trailers with a permanent facility to eliminate major recurring costs and operational risks, including:

$600k/year in displacement mileage for 20 employees

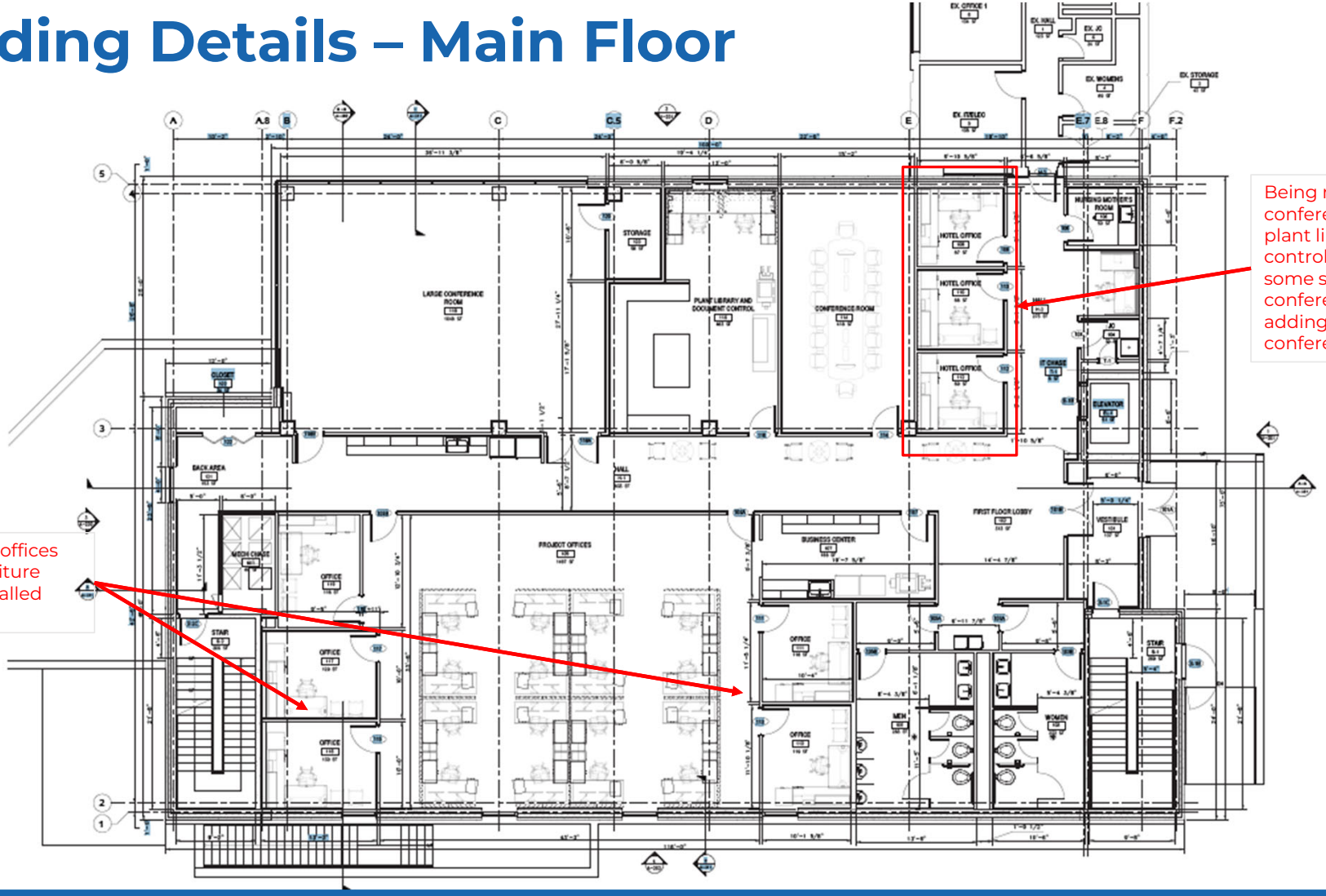
$100k/year in future staffing mileage for 5 employees

$35k/year in trailer O&M and portable restroom rentals

$16.1M–$22M in long-term trailer replacement cycles

Objective: Deliver a permanent building that removes these costs, restores operational efficiency, and supports safe, reliable site operations through 2069 and decommissioning

Building Details – Main Floor

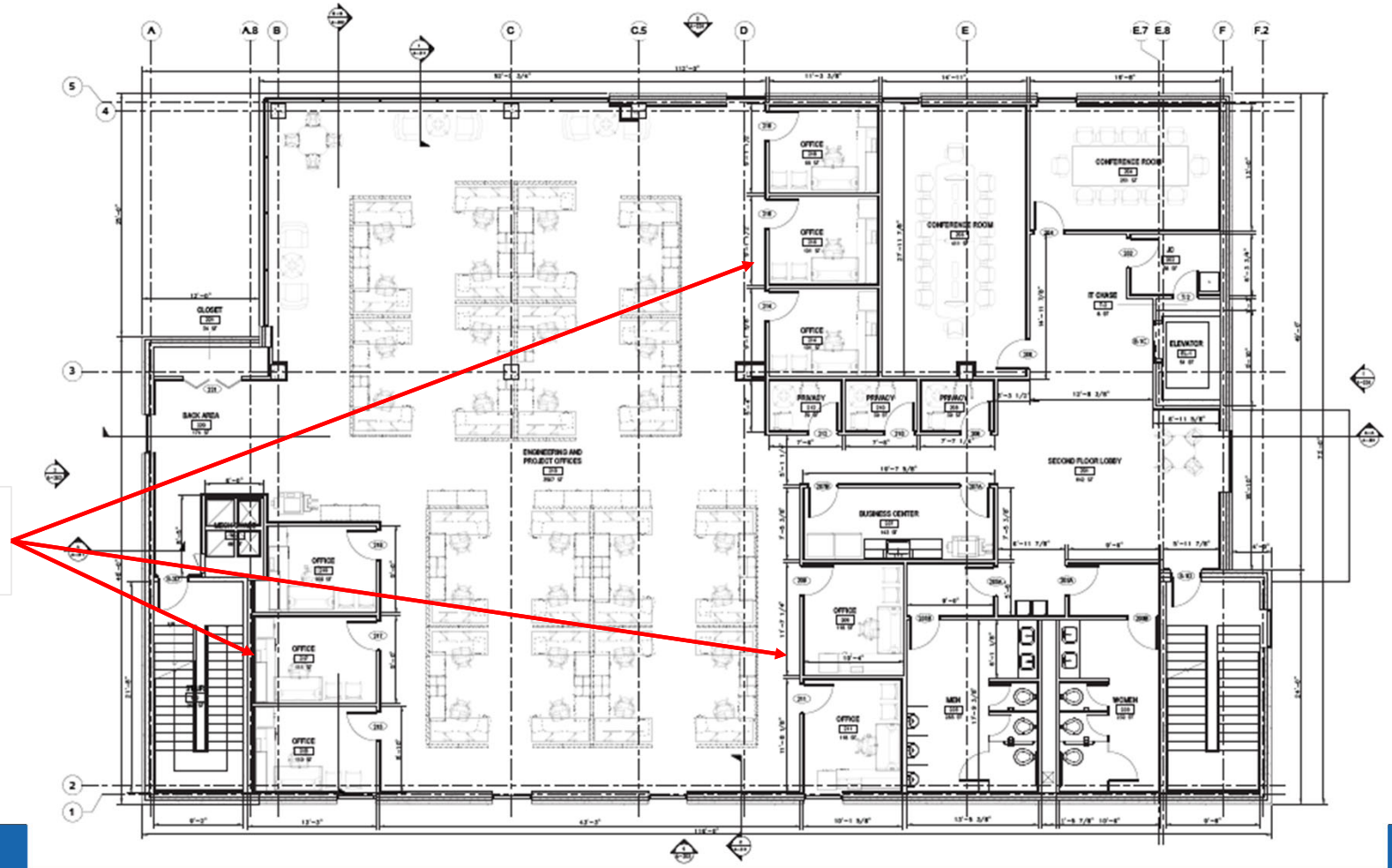


Being removed. Shifting conference room and plant library/document control to the right, adding some space to the conference room and adding space to the large conference room

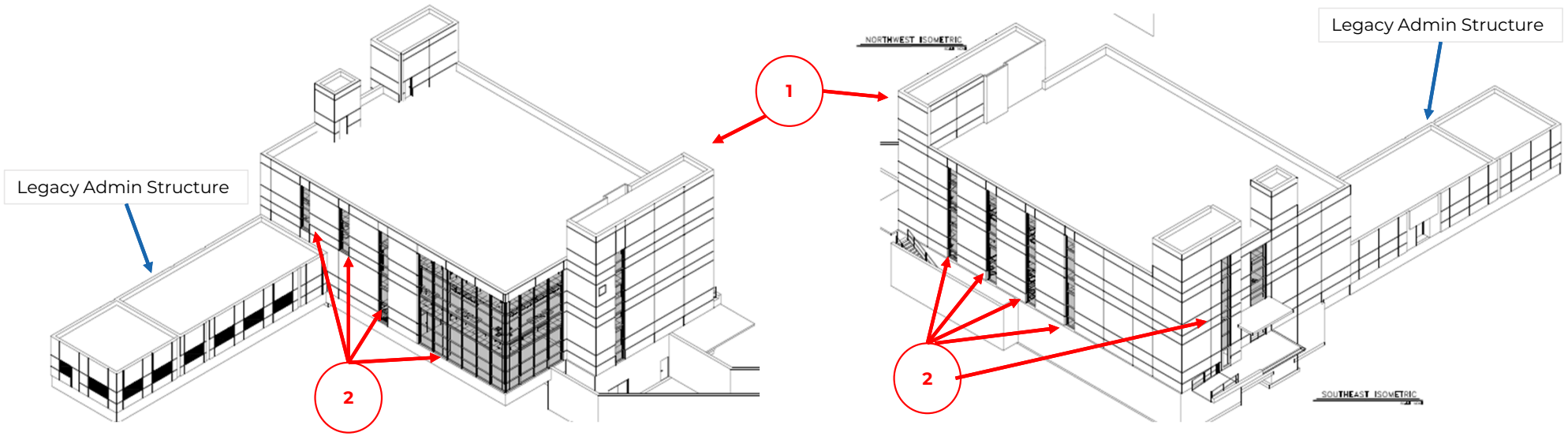
All cubicles and offices as modular furniture only. No hard walled structure

Building Details – Second Floor

All cubicles and offices as modular furniture only. No hard walled structure



Building Details



In process of value engineering changes:
1. Remove roof floor access on West Stairwell (originally existed when building had concept for 3rd floor)
2. Remove curtain wall windows and go to standard opening (punch openings in the concrete that not floor to ceiling, standard window height only similar to legacy admin structure windows

Concept Approval

Ludington Pumped Storage Dike Load Center replacement.

Date: 6/10/2024

Prepared by: Paul Ohep



Figure 1. Ludington pumped storage station.

Executive Summary

Consumers Energy is undertaking a critical infrastructure upgrade at the Ludington Pumped Storage Station to replace aging and deteriorating Dike Load Centers (DLCs). These upgrades are essential for maintaining the operational efficiency, safety, and reliability of this vital energy facility. The project focuses on replacing the high-priority DLCs that are at significant risk of failure, ensuring continued support for the station's critical functions.

Current Equipment Issues:

The original Dike Load Centers were installed in the early 1970s and have been considered obsolete since the 1990s. Prolonged operational use and environmental exposure have led to significant corrosion and deterioration. Recent failures, including the replacement of DLC14 and DLC16 transformers, highlight the urgent need for this upgrade. Additionally, parts from the replaced DLC1 and DLC2 have been used for repairs, and a new transformer has been ordered to manage future defects.

Priority Assessment and Replacement Strategy:

Plant and dam safety engineers have categorized the DLCs into high, medium, and low priority for replacement. High-priority DLCs are those that are highly likely to become inoperable within five years and provide electricity to pumps that run frequently to maintain adequate drainage of the dike's asphalt liner. This project will replace 10 high-priority DLCs identified as critical for safe and reliable operation.

Financial and Operational Impact:

Failure to replace the high-priority DLCs could result in significant operational disruptions and extended downtimes, with estimated shutdowns potentially lasting up to a year due to obsolescence issues. The estimated financial impact ranges from $24 million up $55 million for Net Energy Value losses and $101.5 Million for potential capacity losses.

Conclusion:

The replacement of the outdated and deteriorating Dike Load Centers is crucial for preventing extensive damages and operational interruptions at the Ludington Pumped Storage Station. This targeted approach ensures that the most critical components are addressed promptly, supporting the facility's long-term operational efficiency and safety. By investing in this strategic upgrade, Consumers Energy is committed to maintaining the reliability of Michigan's energy infrastructure while mitigating potential financial and operational risks.

Financial Summary

Funding Type:	Capital
Initial approved cost:	51% dollars - $4,555,000. 100% dollars – $8,931,372
New revised cost:	51% dollars - $**10,286,051**. 100% dollars - $**20,168,728**

Proposed Start Implementation Year and span

2019, 8-year span.

Problem Description

The Ludington Pumped Storage facility, crucial for Michigan's energy infrastructure, includes twenty 480-volt Dike Load Centers and one 4160-volt Switchgear. These units power one hundred ninety-three dike pumps and additional support equipment critical to the facility's operations. Failure of a Dike Load Center would result in an area of the reservoir where the asphalt liner is inadequately drained, potentially leading to an increase in pore water pressure both on the upstream face and at the downstream toe of the dike.

Issues with Current Equipment:

- **Age and Obsolescence:** The original Dike Load Center equipment was installed in the early 1970s and has been considered obsolete since the 1990s.
- **Corrosion and Deterioration:** Prolonged operational use and environmental exposure have led to significant corrosion and deterioration.

Recent Failures:

- Dike Load Center 14 (DLC14) transformer failed and replaced in 2023.
- Dike Load Center 16 (DLC16) transformer failed and replaced in 2024.
- Other repairs have utilized parts from the old DLC1 and DLC2 load centers, which were replaced last year.
- Due to the lack of spares and long lead times, the current strategy to manage the existing risk involves ordering a new transformer to replace any future defects in the remaining 18 DLCs. This approach will bridge the gap until DLC3 is replaced at the end of next year as part of this project.

Risks Posed by Equipment Failure:

- **Operational Impact:** The Centers are essential for distributing power to the dike drain pumps and pumping relief wells that maintain the structural integrity and safety of the reservoir. For these reasons, Dike pumps are required to be operational.

Critical Functions of the Dike Load Centers:

- **Dike Drain Pumps:** They maintain the drained condition of the dike's upstream face, protecting the asphalt liner from pressure-induced damage.
- **Pumping Relief Wells:** These wells manage groundwater levels, maintaining them at preconstruction levels to prevent dike stability issues.

Consequences of Potential Failure:

- **Study Findings:** An engineering study completed in 2020 indicated that the Dike Load Centers are in poor condition, leading to operational hesitancy in cycling them due to potential recovery failures.

- **Operational Disruption:** Failure would lead to insufficient drainage in parts of the reservoir, increasing the risk of structural failures by elevating pore water pressure upstream and downstream.

Priority Assessment by Plant and Dam Safety Engineers:

- **Priority Categorization:** Plant engineers, along with dam safety engineers, have categorized the Dike Load Centers (DLCs) into high, medium, and low priority for replacement. High priority DLCs provide electricity to pumps that are in service for many hours due to the inherent drainage features of the dike itself. These pumps are critical for providing adequate drainage to the asphalt liner, a vital part of the dike's structural integrity. Therefore, the load centers that supply electricity to these frequently running pumps need to remain operational.
- **High Priority DLCs:** Out of the 20 DLCs, 10 have been identified as high priority based on the aforementioned criteria. This project is focused on replacing these 10 high-priority DLCs to ensure the continued safe and reliable operation of the Ludington Pumped Storage facility.

Conclusion: The necessity to replace the outdated and deteriorating Dike Load Centers is critical, not only for maintenance but also to ensure the facility's operational efficiency and safety. This replacement is needed to prevent possible extensive damages and operational interruptions, with a focused approach on the 10 high-priority DLCs identified by plant and dam safety engineers. The list of high, medium, and low priority DLCs is displayed in Figure 2.

Alternative Solutions/Alternatives Considered

1. Do Nothing - $101.5M in potential capacity losses + minimum $24M in Net Energy Value losses

This option involves not replacing the outdated and deteriorating 480-volt Dike Load Centers and the 4160-volt Switchgear at the Ludington Pumped Storage facility.

Immediate Implications:

- **Continued Deterioration:** The Dike Load Centers and Switchgear, already in a state of significant corrosion and obsolescence, will continue to degrade without any intervention.
- **Operational Reluctance:** As noted, the Operations Department is currently hesitant to cycle the Dike Load Centers due to concerns over their reliability and the potential inability to recover them if they fail.

Long-term Consequences:

- **Increased Risk of Failure:** Ongoing deterioration will likely lead to the eventual failure of the Dike Load Centers, which are critical for the operation of the dike pumps and related infrastructure.
- **Inadequate Reservoir Drainage:** Failure of the Dike Load Centers would result in inadequate drainage of the reservoir's asphalt liner. This can increase pore water pressure both on the upstream face and at the downstream toe of the dike, leading to structural vulnerabilities.

Impact on Facility Operations:

- **Operational Shutdown:** The most severe impact of this option is the potential complete loss of operational capability at the Ludington Pumped Storage Station. Due to obsolescence issues with the high-priority Dike Load Centers, there is no quick way to obtain replacement parts, which are essential for safe operation. Without these crucial components readily available, the pond/reservoir would not be safe for continued operation, resulting in an estimated downtime of a full year.
- **Extended Downtime and potential Capacity Losses**: The unplanned downtime not only involves higher direct repair costs but also results in significant operational and revenue losses due to the plant's inability to generate power during the period of inactivity. Given the obsolescence issues, the assumed shutdown would extend to a full year. From a capacity position, a forced outage would necessitate replacing the lost capacity to avoid future accreditation impacts. The potential capacity loss cost, based on capacity replacement costs valued at 75% of CONE (Cost of New Entry), would be substantial. With CONE set at $127K/MW-year, 75% of CONE equals $95K. Considering the average Zonal Resource Credits (ZRCs) for all Ludington units is 178, if all 6 units were lost for a year, the cost would be:

  178 ZRCs * 6 units * $95K = $101.5 million.

- **Net Energy Value (NEV) and Locational Marginal Prices (LMPs)**: In the event of a forced outage of all six units at the Ludington Pumped Storage Station for a full year, the financial impact can be assessed using Locational Marginal Prices (LMPs). LMP is the cost of supplying the next increment of electricity demand at a specific location in the grid, reflecting supply and demand balance, transmission constraints, and generation availability. The analysis compared similar high and low load days to estimate the impact on LMPs during the outage.
    - Analysis Details:

      During a recent outage period (9/27/23-10/13/23), the average LMP was $33.63/MWh, compared to an annual average of $30.65/MWh.

      Day-Ahead LMP Comparison:
        - Lower Load Days:
            - 29-Sep: $34.96/MWh (Delta: $3.65/MWh)
            - 5-Oct: $32.88/MWh (Delta: $1.57/MWh)
        - Higher Load Days:
            - 3-Oct: $47.02/MWh (Delta: $16.37/MWh)
            - 4-Oct: $39.64/MWh (Delta: $10.11/MWh)
        - The deltas represent the difference between the specific day's LMP and the average LMP for similar days based on load and weather profiles.

    - Financial Impact:

        - It is estimated by our internal economics forecast models that the net energy value (NEV) loss for this scenario would be a minimum of **$24 million** for one year. That estimate is based upon normal conditions. Based on load variability we can expect LMPs to increase by between $3/MWh and $16/MWh which will impact the NEV forecast.

        - At $3/MWh annual average increase in LMPs due to the loss of Ludington, the $24 million net energy loss would increase to **$30 million.**
        - At $16/MWh annual average increase in LMPs due to the loss of Ludington, the $24 million net energy loss would increase to **$55 million.**

Conclusion:

- The 'Do Nothing' option, while avoiding immediate expenditure, poses significant long-term risks including the potential for operational halt as well as significant costs for capacity and energy losses should the site be forced to shut down. The failure to replace the critical Dike Load Centers could lead to irreversible damages and operational challenges, making this approach highly inadvisable.

2. Replace as needed – Internal Estimated Cost of $28,236,219

Description of the Approach:

- **Reactive Replacement:** This alternative involves replacing individual Dike Load Centers at the Ludington Pumped Storage facility only as they fail. While this reactive approach has been previously applied to cabling, where failures were addressed on a case-by-case basis, it's important to note that cabling replacements are significantly simpler. In contrast, replacing Dike Load Centers involves a more complex process. Since the replacements are not like-for-like due to updates in technology and regulation, several additional steps, including system integration and infrastructure modifications, are necessary to facilitate these replacements.

Current State of Equipment:

- **Dike Load Center Maintenance:** Over the years, specific breakers within the Dike Load Centers have been maintained to extend their operational life without replacing entire units. However, this approach is increasingly becoming non-viable due to the growing obsolescence of the parts involved.

Risks and Challenges:

- **Increased Frequency of Failures:** Given the structural deterioration of the Dike Load Centers, failures are expected to become more frequent.
- **Risk of Operational Disruption:** The lengthy lead times required for the design, procurement, and installation of replacement units introduce significant risks. Should multiple Dike Load Centers fail simultaneously, the facility could experience substantial operational disruptions. The complex engineering planning necessary for each unplanned replacement extends these lead times further.
- **Inconsistency in Installations:** Replacing components on a piecemeal basis as they fail leads to non-standard, one-off installations. This inconsistency can complicate maintenance procedures, escalate costs, and diminish overall system efficiency.

Long-term Implications:

- **Continued Reliability Issues:** The approach does not address the underlying issue of aging and obsolescence across all Dike Load Centers but rather postpones comprehensive solutions.
- **Operational Inefficiency:** As more components are replaced on an as-needed basis, the system may become a patchwork of old and new technology, potentially decreasing operational efficiency and increasing maintenance complexity.

Financial Impact:

- **Cost Escalation:** Due to the inefficiencies of this option and the complexities involved in engineering planning and procurement of components, the cost estimates for replacing the high priority DLCs are escalated by an estimated 40%. These increased costs are attributed to the emergency nature of unplanned replacements, which require rapid response and often premium pricing for expedited services.

- **Estimated Project Cost:** Consequently, the total estimated project cost for this approach, factoring in all associated inefficiencies and complexities, is estimated at $28,236,219 in 100% dollars. This figure reflects the significant financial burden imposed by the ad hoc replacement strategy under conditions of urgency and operational necessity.

Conclusion:

- While this option allows for spreading out expenditures over time and addressing issues as they arise, it carries significant risks of unplanned operational halts and safety concerns. The piecemeal approach might also lead to increased costs over time due to emergency replacements and the inefficiencies of managing a non-standardized system. Therefore, this option, though seemingly less capital intensive initially, will lead to higher overall costs and operational challenges.

3. Option 3 - Staged Phased replacement of high priority DLCs only - Initial internal estimate of $8,931,372 (100% dollars), new revised internal estimate $20,168,728 (100% dollars)

This option proposes a structured and phased replacement of the ten most critical Dike Load Centers at the Ludington Pumped Storage facility. This plan is designed to prioritize the replacement of units that are most problematic first, with subsequent phases targeting units that are currently less prone to failure. The other 10 DLCs will be considered under a different project once the data suggests that replacement is warranted.

Planned Phases of Implementation:

- **Priority-Based Replacement:** The initial phase targets the Dike Load Centers that are in the worst condition or that have shown the most frequent issues. This approach mitigates the most immediate risks to facility operations.
- **Subsequent Phases:** Following the initial replacements, the remaining Dike Load Centers would be replaced in a planned sequence over the next six years, based on their assessed condition and risk of failure.

Benefits of the Staged Approach:

- **Risk Management:** By prioritizing the most critical replacements first, this plan not only effectively manages the risk of sudden failures that could disrupt operations but also ensures that the remaining Dike Load Centers continue to operate reliably for several years. The strategy includes utilizing parts from the DLCs that are being decommissioned to stock an inventory of spare and refurbished parts. This approach will provide a robust support system for the Dike Load Centers that are not scheduled for immediate replacement, thereby extending their operational lifespan and enhancing overall plant resilience.

- **Operational Continuity:** A phased approach ensures that replacements are done systematically, minimizing the impact on daily operations and allowing for better planning and resource allocation.
- **Equipment Compatibility:** Implementing a uniform replacement strategy across all units ensures that the new equipment is compatible, avoiding the complications associated with non-standard, one-off installations.

Long-term Strategic Advantages:

- **Enhanced System Reliability:** With new and compatible equipment installed in a phased manner, the overall reliability of the Dike Load Centers is greatly improved, ensuring stable operations for the foreseeable future.
- **Cost Efficiency:** Although this approach requires upfront planning and investment, it is more cost-effective in the long term compared to emergency replacements or piecemeal upgrades. It allows for budget predictability and can leverage bulk procurement discounts.

Option 4 – Full replacement of all 20 DLCs. Internal Estimated Cost - $37,827,823.(100% dollars)

Option 4 proposes a comprehensive replacement strategy for all 20 Dike Load Centers (DLCs) at the Ludington Pumped Storage facility. This option extends beyond the high-priority DLCs addressed in Option 3 to include the remaining 10 DLCs, which have exhibited significantly fewer failures and operational issues over the past five years.

Rationale for Exclusion from High Priority List:

- **Lower Failure Rates:** The 10 DLCs not included in the high-priority list have shown considerably lower failure rates. These units primarily consist of DLCs with dry wells where the pumps have not been operating frequently.
- **Operational Observations:** Due to the minimal operational demand on these DLCs, the wear and stress on components have been substantially less, leading to a decreased likelihood of immediate failures.

Financial Considerations:

- **Cost of Full Replacement:** The total cost for implementing Option 4, which entails replacing all 20 DLCs, is estimated at $37,827,823 (100% dollars). This figure represents a significant increase from the initial estimates made five years ago, which did not account for the escalated costs due to inflation, increased material costs, and more comprehensive engineering requirements now deemed necessary.
- **Comparison to Reduced Scope:** While Option 4 ensures that all components are uniformly modernized and potentially reduces future disparate maintenance schedules, the additional cost compared to Option 3 is considerable. Given the lower risk associated with the 10 non-high-priority DLCs, the additional expenditure does not proportionately increase the value or return on investment when compared to the focused scope of replacing only the high-priority units.

Conclusion: Option 4, while offering a uniform upgrade across all DLCs and potentially simplifying future maintenance, does not present a significantly higher value over Option 3 given the substantial additional costs involved. The decision by subject matter experts in engineering to prioritize Option 3 over Option 4 is based on a strategic assessment of risk, operational need, and financial efficiency. The comprehensive replacement of all 20 DLCs under Option 4 does not align sufficiently with the incremental benefits when weighed against the additional financial investment required.

Recommended Alternative: Option 3 - Staged Phased replacement of high priority DLCs only - Initial internal estimate of $8,931,372 (100% dollars), new revised internal estimate $20,168,728 (100% dollars)

In evaluating the options for addressing the critical condition of the Dike Load Centers at the Ludington Pumped Storage facility, a comprehensive analysis of operational, financial, and technical factors has been conducted. The following section outlines the justification for selecting Option 3, the staged phased replacement plan.

1. **Risk Mitigation:**
    - **Immediate Risk Reduction:** By prioritizing the replacement of the most deteriorated Dike Load Centers, this plan directly addresses the highest risk components within the system. This proactive measure prevents potential failures that could lead to significant operational disruptions or safety concerns.
    - **Controlled Risk Exposure:** The phased approach reduces the likelihood of encountering multiple failures simultaneously, a critical factor considering the long lead times required for designing, procuring, and installing new equipment.
2. **Operational Continuity and Efficiency:**
    - **Minimized Operational Disruption:** Staging the replacements ensures that the facility remains operational without significant downtime. Replacing equipment in a controlled, planned manner prevents the sudden loss of capacity that could result from emergency replacements following unexpected failures.
    - **System Uniformity and Standardization:** As replacements are made systematically, the new installations will be uniform and standardized, which significantly simplifies maintenance and operation. This uniformity ensures all components communicate and function optimally within the system, enhancing overall operational efficiency.
3. **Cost Management and Budget Planning:**
    - **Predictable Expenditure:** A phased plan allows for better financial planning and resource allocation. Budget impacts are spread over several years, which can be

accommodated more easily within annual capital budgets, avoiding the financial strain of unplanned, large-scale expenditures.

- **Economies of Scale in Procurement:** Purchasing equipment in planned stages rather than as one-off replacements can reduce costs through bulk buying and potentially negotiating more favorable terms with suppliers.

4. **Long-term Strategic Benefits:**

- **Enhanced Longevity and Reliability:** Systematically upgrading the Dike Load Centers ensures that all components are modern, robust, and capable of meeting the operational demands of the facility. This not only extends the life of the infrastructure but also boosts its reliability and performance.

Conclusion:

The selection of Option 3, a staged phased replacement plan, is justified based on its comprehensive approach to managing the inherent risks associated with the Ludington Pumped Storage facility's Dike Load Centers. This option balances the need for immediate action on the most critical components with the practicalities of budget, operational continuity, and long-term reliability.

Budget Revision Justification

The initial budget for the replacement of the Dike Load Centers (DLCs) at the Ludington Pumped Storage facility was set over five years ago, based on a 'like-for-like' replacement strategy. Since then, the project estimate has more than doubled, primarily due to significant changes in the technical requirements of the replacement units. The detailed analysis of these changes highlights several key factors contributing to the increased cost:

1. Changes in Size and Design Requirements:

- **Increased Physical Size:** The replacement DLCs are now 2.5 to 3 times larger than the original units. This size increase is mainly due to current industry standards and regulatory requirements not in place or anticipated during the initial budgeting.
- **Foundation Modifications:** The larger size of the new DLCs necessitates the demolition of the existing foundations and the construction of significantly larger ones. This requirement was not included in the original plan, which had assumed the new units would fit the existing foundations.

2. Infrastructure and Installation Adjustments:

- **Conduit and Wiring Changes:** The original project plan assumed that the new DLCs could use the existing pathways for wiring and cabling. However, due to the changed positioning and increased size of the new units, this is no longer feasible. Additional conduit installation is now necessary, along with more extensive wiring than previously planned.

- **Junction Box Installation:** The new layout and increased complexity of the electrical connections require the installation of additional junction boxes. These elements are essential to safely manage and distribute the electrical loads from the larger DLCs, further adding to the project cost.

3. Unforeseen Technical Challenges:

- **Engineering and Design Revisions:** The significant alterations in the project's scope, necessitated by the larger size and different configuration of the replacement DLCs, have required additional engineering and design work. This revision process has introduced delays and increased costs associated with specialized labor and technical expertise.

Conclusion:

The substantial increase in the budget estimate for the Dike Load Center replacement project at the Ludington Pumped Storage facility is a direct result of changes in the physical size of the units, enhanced regulatory requirements, and the complexities involved in retrofitting new technology into an existing infrastructure. These factors were not fully anticipated in the initial budget, resulting in the need for a revised financial plan that reflects the current project realities.

Scope of work

This scope of work details a revised strategy focusing specifically on the replacement of high-priority Dike Load Centers (DLCs) at the Ludington Pumped Storage facility. This initiative spans a four-year timeline and is designed to address the most critical DLCs that have experienced multiple failures over the past five years, ensuring reliable and safe operation of the plant.

Project Details:

High-Priority DLC Replacement:

- **Objective:** Implement a phased replacement of the ten most critical 480 Volt Dike Load Centers based on an assessment by the environmental and dam safety teams.
- **Tasks:**
    - Demolish existing structures and construct new foundations as needed for the modern DLCs.
    - Install new Dike Load Centers that comply with current regulatory standards and operational requirements.

Utilization of Existing Equipment:

- **Objective:** Efficiently utilize existing resources by repurposing used and recently replaced dry transformers and electrical equipment as spares for the remaining lower-priority DLCs.

Phased Implementation Schedule:

- **2023:** Complete the replacement of DLCs 1 & 2 (completed).
- **2025:** Replace DLCs 3 & 4, focusing on critical components and integration with existing plant systems.
- **2026:** Address DLCs 17 & 16, incorporating lessons learned and feedback from previous installations.
- **2027:** Update DLCs 15 & 5, ensuring continuity and system integrity.
- **2028:** Finalize replacements with DLCs 12 & 11, completing the priority updates.

This targeted approach allows for a focused upgrade of the most critical components within the facility, aligning resource allocation with the most immediate needs for reliability and safety. By prioritizing high-risk DLCs and strategically scheduling their replacement, the project ensures ongoing compliance with safety and operational standards while optimizing the use of existing resources. This phased strategy minimizes disruption and maximizes the efficacy of the upgrades, ensuring the long-term sustainability of the Ludington Pumped Storage facility's operations.

Funding and Timing

- Funding that has been previously committed for this project: $4,278,409 (51% dollars)
- A Scheduled outage is required for this project.
- Desired implementation year: first year spend 2019 with installation and closeout finishing 2029.
- System Engineer: Tarik Butrus

Conceptual Estimate

Year	Loaded Cost	Description
2019	**$43,747**	51% dollars. Engineering and planning
2020	**$668,263**	51% dollars. Engineering and planning
2021	**$1,013,244**	51% dollars. Engineering and planning. Procurement and preparation for installation
2022	**$1,665,599**	51% dollars. Engineering and planning. Procurement and preparation for installation
2023	**$887,558**	51% dollars. Engineering and planning. Installation of DLC 1 & 2
2024	**$679,492**	51% dollars. Engineering and planning.
2025	**$1,186,497**	51% dollars. Installation of DLC 3 & 4
2026	**$1,309,572**	51% dollars. Installation of DLC 17 & 16
2027	**$1,308,113**	51% dollars. Installation of DLC 15 & 5
2028	**$1,421,968**	51% dollars. Installation of DLC 12 & 11
2029	**$102,000**	Monitoring, Post Maintenance testing, Documentation and Closeout

Total Cost: 51% dollars - $10,286,052 100% dollars – $20,168,728

Asset Strategy Approval Comments

Asset Strategy endorses the reduced scope approach of Option 3, focusing exclusively on replacing high-priority Dike Load Centers at the Ludington Pumped Storage facility. This decision is based on a detailed risk assessment and cost-benefit analysis performed by our engineering experts, who recommend prioritizing replacements where they are most needed due to repeated failures in the last five years. By concentrating resources on the most critical areas, we ensure a cost-effective allocation of capital while maintaining operational reliability and safety.

This investment **is** included in the current electric rate case.

Amount set for Bridge year: $990,000

Amount set for test period: $852,000

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric supply		

Concept Approval

Ludington Pumped Storage Unit Governors

Date: 6/10/2024

Prepared by: Paul Ohep



Figure 1. Ludington pumped storage station.

Executive Summary

The Ludington Pumped Storage Plant Unit Governor systems are essential for hydraulic control and overall plant safety. Currently, the system is obsolete and lacks redundancy, posing significant risks to reliability and safety. A comprehensive upgrade is needed to address these issues.

Problem Description

The governor system controls water flow through wicket gate adjustments, managing various operational modes, including emergencies. It is identified as high-risk due to its lack of redundant controls and mechanical defenses.

Current Challenges

The Atlas electrical controller, installed in the early 2000s, lacks OEM (Original Equipment Manufacturer) support and essential parts. Only one spare controller exists for all six units, and its reliability is uncertain. Additionally, the controller's limited compatibility with the plant's Ovation system complicates troubleshooting. Mechanical failures frequently impact wicket gate operations, and historical oil pump failures risk operational mechanisms.

Alternative Solutions Considered

Do Nothing: Estimated at $19.8M per occurrence, this option poses high failure risks, potential capacity, and NEV losses, and increased dam failure risk.

Controls Replacement Only: Estimated at $4.0M, this option does not address critical mechanical components, leading to incomplete risk mitigation.

Partial Replacement (Selected Option): Estimated at $17,719,930, this approach includes a selective upgrade of control and mechanical systems, integrating with the Ovation system. It enhances reliability, ensures spare part availability, and improves safety.

Conclusion

The partial replacement option is chosen for its balanced approach, addressing critical risks without unnecessary expenditure. It ensures long-term stability and safety by upgrading both control and mechanical components, aligning with industry best practices and leveraging modern technological advancements.

Financial Summary

Funding Type: Capital

Cost: 51% dollars - $**9,037,164**. 100% dollars - $**17,719,930**

Proposed Start Implementation Year and span

2022, 8-year span.

Problem Description

The Ludington Pumped Storage Plant employs a sophisticated governor system responsible for hydraulic control over water flow through the plant's pump/turbine system. This system is critical for managing the unit's operations across various modes, including emergency scenarios, power generation, and mechanical safety.

System Description and Issues

1. **Governor System Functionality:**
    - **Primary Role:** Controls water flow through adjustments in wicket gate positions, influencing power output levels.
    - **System Components:** Utilizes high-pressure oil for operating servo motors linked to wicket gates.
    - **Operational Scope:** Ensures smooth transitions in operational modes such as generation control, pump operations, and emergency dewatering.
2. **Critical Risk Factors:**
    - **System Reliability:** Identified as a high-risk component in the "Issue-Specific Semi-Quantitative Risk Analysis for Emergency Overflow Spillway Operation" report due to its lack of redundant controls and mechanical defense in-depth components.
    - **Safety Implications:** Essential for preventing scenarios like reservoir overtopping and dam failure, which pose significant safety risks.

Current System Challenges

1. **Atlas Electrical Controller Issues:**
    - **Aging Technology:** Installed in the early 2000s; lacks current OEM support with essential parts no longer available from the original manufacturer, General Electric.
    - **Spare Unit Risks:** Currently, only one spare Atlas controller is available for all six units, which increases the risk of operational disruptions if the active unit is damaged by external factors like lightning strikes or overheating. Additionally, the spare controller is the same age as the original equipment and has not been used for several years, so its reliability cannot be fully guaranteed at this time.
    - **Integration and Maintenance Challenges:** The Atlas controller’s limited capability with the plant's Ovation system complicates troubleshooting, leading to longer downtime during failures. This system’s shortcomings are compounded by its inadequate production historian capabilities.
2. **Mechanical System Deterioration:**
    - **Operational Reliability:** Frequent mechanical failures have impacted the effectiveness of wicket gate operations, posing risks of "runaway" unit conditions under failure modes. The probability of a runaway unit condition under certain

modes of operation does exist but could be minimized by modern design features.

- **Component Wear:** Historical oil pump failures could cause binding of the distributing valve, making the operating mechanism stuck in its current position.

3. Outdated Component Concerns:

- **Reliability Threats from Aging Components:** The existing electrical system contains various original relays, timers, and instruments that are beyond their service life, posing risks to unit reliability.
- **System Obsolescence:** Continuous reliance on these outdated components without readily available replacements heightens the risk of unexpected failures.
- **OEM Support Discontinuation:** Original system components are obsolete, with sporadic support transitions impacting long-term maintenance and parts availability.

4. Conclusion

The Unit governor systems at the Ludington Pumped Storage Plant are crucial for ensuring safe and efficient plant operations. Currently, the system is compromised by outdated components and a lack of redundancy, highlighting a pressing need for a comprehensive upgrade. A critical spare component of this system (Atlas) has become completely obsolete, significantly increasing the risk to the station. Fortunately, the past 50 years have seen significant technological advancements that address many of the issues historically experienced with the LPS governors. These modern solutions not only enhance the system's reliability but also correct previous deficiencies, providing a valuable opportunity to significantly improve the system’s performance and safety. Upgrading these components is crucial to mitigate the high level of risk associated with the current governor system.

Alternative Solutions/Alternatives Considered

1. Do Nothing – Estimated cost of $19.8M per occurrence.

The "Do Nothing" alternative involves maintaining the current governor systems at the Ludington Pumped Storage Plant (LPS) without implementing the proposed upgrades. This option would forgo any modernization efforts and continue operations with the existing Atlas controllers and mechanical systems, which are significantly outdated and lack modern safety features.

Implications

1. **Reliability and Risk:**
    - **Failure Probability:** The current probability of a critical failure in this system is estimated at 20% within the next five years, with an annual increase of 5% thereafter. A critical failure is defined as an event that causes a forced outage lasting at least two weeks.
    - **Unit reliability:** A scenario in which our only spare Atlas controller failed if in use would result in one of the units being offline for 8 months.
2. **Increased Costs:**
    - **ROR and O&M Costs:** Continuing with the existing system will result in increased Repair, Operating, and Maintenance costs due to the aging components that are nearing or have reached the end of their service life.
    - **Component Replacement – cost of $4.4M (100% dollars):** As many parts are now obsolete, finding suitable replacements could be costly and potentially require custom solutions, further increasing expenses. If Atlas were to fail the plant only has 1 spare Atlas for all six units and no ability to obtain a new spare. The cost of replacement for one unit would be an estimated $4.4M. This considers all loadings and a 50% markup for emergency rush installation.
    - **Net Energy Value losses - $2.7:** An 8-month outage of a single unit at Ludington Pumped Storage Plant is estimated to result in a net energy value (NEV) loss of $2.7 million. This estimation is based on an annual NEV of $4 million per unit. The calculation assumes a worst-case scenario, as such an extended outage would result from an unplanned failure rather than scheduled maintenance.
    - **Potential Capacity losses - $12.7M:** If one unit is out of service for 8 months, the estimated potential capacity losses are $12.7 million. This is based on the following assumptions:
        1. Cost of New Entry (CONE): $127K/MW-year
        2. 75% of CONE: $95K/MW-year (used for calculation)
        3. With 178 average Zonal Resource Credits (ZRCs) for all Ludington units, the loss calculation is as follows:

4. Replacement for 3 out of 4 seasons (75% of the year): 178 ZRCs * 75% * $95K = $12.7M
5. 3.

This estimation assumes the need to replace capacity during a forced outage to avoid future accreditation impacts (no three-year penalty), valuing capacity at 75% of CONE.

- **Safety Concerns:** This option neglects one of the highest contributing systems to reservoir overtopping risks as identified in the “Issue-Specific Semi-Quantitative Risk Analysis for Emergency Overflow Spillway Operation” report. Continuing with the current system could significantly increase the risk of dam failure due to inadequate response capabilities during critical conditions.

3. **Technological Obsolescence:**
    - **Outdated Technology:** The current unit governor systems use technology surpassed in efficiency, reliability, and safety**.** Better technology exists today that can substantially decrease the risk of failure and improve operational control.

Conclusion

While initially cost saving, the "Do Nothing" option presents substantial long-term risks and costs, making it an unsustainable choice. The increasing likelihood of failures on obsolete critical components, combined with the outdated nature of the current systems and the availability of advanced technology, strongly argues against this alternative.

2. Controls replacement only– Internal loaded estimate of $4.0M (100% Dollars)

Option 2 focuses on the replacement of the electrical control systems for all six units at the Ludington Pumped Storage Plant. This option is limited to updating the control systems without addressing any of the mechanical components.

Implementation Details

- **Cost and Timing:** The project is estimated to cost $4.0M in capital expenditure. Implementations are planned during the plant's scheduled outages, which occur every three years and last for three weeks, thereby minimizing operational disruptions.
- **Equipment Lifespan:** The upgraded electrical control systems are expected to last 20-25 years, significantly improving the reliability of control operations.

Limitations

- **Exclusion of Essential Mechanical Components:** Option 2 focuses solely on updating the electrical controls and does not address the critical mechanical components necessary for the plant's operational integrity. The following key components identified

by internal subject matter experts as crucial for reliable operation remain unchanged and are not included in this upgrade:

- **Distribution Valve (Secondary Mechanical Rate):** Essential for controlling the flow and pressure within the system.
- **EHI (Electro-Hydraulic Interface):** Crucial for interfacing between electrical signals and hydraulic operations.
- **Retarding Valves for Wicket Gate Servomotors**: Important for controlling the speed and positioning of the wicket gates.
- **Drain Oil Piping for Governor Pressure Tank:** Necessary for maintaining proper oil pressure and flow.
- **Governor Oil Sump Sight Glass and Sump Foaming**: Critical for monitoring and maintaining oil levels and quality (first unit only).
- **Emergency Distributing Valve Bypass:** Provides a critical safety mechanism during system failures.
- **Hydraulic Piping and Tubing:** Integral for the seamless transfer of hydraulic fluids throughout the system.
- **Air Brake System:** Essential for the safe operation and maintenance of mechanical movements within the governor system.
- **Incomplete Solution:** While the control upgrades may enhance certain operational aspects, critical mechanical issues remain unmitigated, which can lead to increased system vulnerability.

Risk Assessment

- **Initial Failure Probability Reduction:** The likelihood of critical failures is projected to decrease to 3% within the first five years post-implementation.
- **Long-term Risk Increase:** The probability of failures is expected to increase by 2.5% annually after the initial period, due to the aging and unreplaced mechanical components.

Conclusion

While Option 2 offers a less expensive alternative with minimal disruption to plant operations, it provides an incomplete solution by neglecting essential mechanical components of the system. This option's scope is limited to control replacement, which does not address the mechanical vulnerabilities crucial for reliable system operation. The failure to replace key components identified by our subject matter experts results in this option not being viable for ensuring the long-term operational stability and safety of the plant.

3. Select Replacement – Internal estimate $17,719,930 (100% dollars).

Option 3 entails a selective upgrade of the control and mechanical systems at the Ludington Pumped Storage Plant, targeting components most critical for improving reliability and operational efficiency. This option integrates a new control scheme compatible with the upcoming Ovation system and replaces essential mechanical components that are nearing the end of their service life and have a history of damage or failure.

Implementation Details

- **Control System Upgrade:**
  - **Integration with Ovation System:** The new control system will be designed to pair seamlessly with the advanced Ovation system, enhancing the plant's operational capabilities through improved control and diagnostics.
  - **Electrical Components Replacement:** Critical electrical components and instruments will be updated to ensure ongoing spare parts availability and to maintain system reliability.
- **Mechanical System Upgrades:**
  - **Component Replacement:** Major mechanical components such as the distributing valve, pilot valve, unloader, and brake valve will be replaced due to their critical role in system operation and current end-of-life status.
  - **Retention of Key Components:** Servo motors, accumulators, significant portions of the power piping, and the existing cabinet structure will be retained, minimizing the scope and cost of physical changes.
- **Safety Enhancements:**
  - **Defense in Depth Improvements:** New safety features, including a distributing valve bypass, will be incorporated to enhance the system’s overall safety profile and operational resilience.
- **Cost and Schedule:**
  - **Estimated Cost:** The total capital expenditure for this option is estimated at $17,719,930 for all units.
  - **Implementation Schedule:** The replacement work will be strategically planned to coincide with scheduled outages to minimize disruption to plant operations.

Industry Benchmarking

- **Sector Best Practices:** Feedback from major hydroelectric OEMs (Original Equipment Manufacturer) and budgetary assessments indicate that this partial replacement strategy is commonly adopted by utilities with similar units. This approach aligns with industry best practices and meets reliability targets effectively.

Risk Assessment

- **Balanced Approach:** By selectively replacing and retaining components, this option strikes a balance between cost-efficiency and substantial system improvements. It addresses the most critical vulnerabilities without the need for a complete system overhaul.
- **Reliability and Spare Parts:** Updates to control and mechanical systems will significantly reduce the risk of failures and ensure easier maintenance through improved parts availability.
- **Reduced Initial Failure Probability:** Post-implementation, the probability of a critical failure is estimated to decrease to 1% within the first five years.

Conclusion

Option 3 presents a robust strategy for the governor system modernization at Ludington Pumped Storage Plant. It presents a comprehensive approach to upgrading critical components, ensuring compatibility with new technological standards, and adherence to industry best practices. This approach effectively addresses the plant's needs, proposing a solution that enhances long-term operational stability.

Recommended Alternative: Option 3 - $17,719,930 (100% dollars)

After thorough evaluation of all alternatives for modernizing the governor system at Ludington Pumped Storage Plant, Option 3 - Partial Replacement has been selected as the most viable and beneficial approach. This decision is grounded in a comprehensive analysis of the plant's needs, the potential risks associated with different strategies, and the overall goal of enhancing system reliability and safety while ensuring cost-effectiveness.

Rationale for Partial Replacement

1. **Balanced Approach to Modernization:**
    - **System Compatibility and Upgrades:** The partial replacement will integrate seamlessly with the new Ovation system, enhancing control and monitoring capabilities. This strategy allows for the retention of robust existing components such as servo motors and accumulators, while outdated and critical components like the distributing valve, pilot valve, unloader, and brake valve are replaced to address specific vulnerabilities.
    - **Reduction in Risks:** By replacing obsolete components and improving the system design, this option significantly decreases the likelihood of unit failure and the associated risk of dam failure. Additional safety measures and defense-in-depth features are incorporated to bolster system reliability during extreme conditions.

2. **Cost and Efficiency Considerations:**
    - **Cost-Effective Solution:** Compared to a complete replacement, this option is less costly and avoids unnecessary expenditure on replacing still-functional components. It provides a targeted, effective upgrade without the extensive capital outlays required for a full system overhaul.
    - **Minimized Operational Disruption:** The upgrades can be implemented during scheduled outages, thereby minimizing disruption to plant operations, and reducing the downtime typically associated with more extensive refurbishments.
3. **Addressing Obsolescence and Enhancing Reliability:**
    - **Spare Part Availability:** The upgrade ensures that all replaced components are supported with readily available spare parts, addressing one of the critical vulnerabilities of the current system.
    - **Addressing Legacy Issues:** The existing control system and mechanical components have demonstrated increasing failure rates. This trend is poised to worsen, as highlighted by the rise in failures over the past decade and the expected continuation of this trend. Modernizing these components directly addresses these reliability issues.
    - **Improved OEM Support:** Transitioning to newer systems with robust OEM support from GE/Nexus facilitates better maintenance and quicker responses to system issues, which enhances overall plant reliability.
4. **Enhancements in Monitoring and Troubleshooting:**
    - **Improved Diagnostic Capabilities:** The integration with advanced systems like Ovation enhances the plant's ability to perform condition monitoring and decreases troubleshooting time, directly reducing operational costs and system downtime.
    - **Updated Documentation:** Replacing old, often illegible electrical drawings with updated, accurate documentation will further enhance maintenance efficiency and system operability.

Option 3 - Partial Replacement stands out as the most strategic approach for updating the governor systems at Ludington Pumped Storage Plant. It balances the need for modernization with cost considerations, addresses the critical risks associated with the current system's obsolescence, and aligns with industry best practices for reliability and safety enhancements. By choosing this option, the plant will not only meet current operational demands but also establish a foundation for sustainable long-term performance and safety.

Budget Revision Justification

The initial estimate for the modernization of the governor systems at Ludington Pumped Storage Plant was set at $4.55 million (51% dollars). However, recent developments in the bidding process have necessitated a significant revision of the project budget. The current internal estimate has been adjusted to $9,890,751 (51% dollars), reflecting updated market conditions and actual bids received.

Reasons for Budget Increase

1. **Actual Bids Exceeding Initial Estimates:**

- The lowest cost bid received for the project was slightly under $13 million (100% dollars), significantly higher than the initially estimated $9.1 million. This discrepancy highlights a substantial underestimation in the original financial planning.
- The only other bid received was over $20 million, further indicating that the initial cost expectations were unrealistically low.

2. **Initial Budgeting Basis:**

- The original estimates were based on bids received four years ago. Since then, market conditions have changed, and costs for materials, labor, and technological components have increased, impacting the overall project cost.

Scope of work

The project aims to modernize the governor systems of all six units at Ludington Pumped Storage Plant (LPS). This comprehensive upgrade is designed to enhance operational reliability, safety, and compliance with current technological standards.

Components of Modernization

1. **Controller and Electrical System Upgrades:**
    - **Controller Replacement:** The current Atlas controllers will be replaced with state-of-the-art controllers featuring Human-Machine Interfaces (HMIs) for enhanced user interaction and monitoring.
    - **Auxiliary Electrical Equipment:** Introduction of new auxiliary electrical systems to support the upgraded controllers.
    - **PLC Enhancements:** Additional Programmable Logic Controller (PLC) functionalities will be incorporated to minimize failure modes and provide component redundancy.
2. **Mechanical System Redesign:**
    - **Hydraulic Control Devices:** Installation of new hydraulic controls tailored to address and rectify existing operational challenges.

- **Safety Features:** Implementation of advanced safety features like a distributing valve bypass to mitigate risks associated with unit control loss.

3. **System Compatibility and Integration:**
    - **Ovation System Compatibility:** Ensuring new systems are compatible with the future Ovation system to enhance trending and troubleshooting capabilities.
    - **Drawing Package:** A new, clear drawing package will be provided to replace outdated and illegible documentation, facilitating better maintenance and operational procedures.
4. **Implementation Schedule:**
    - **Staggered Installation:** The upgrade will be executed on two units per year, aligned with each unit's scheduled periodic outage to minimize operational disruption.

Compliance and Longevity

- **Codes and Standards:** All modernization efforts will adhere to applicable international and industry-specific standards.
- **Service Life Specifications:**
    - **Mechanical Components:** Specified for a minimum of 50 years of mechanical service life.
    - **Electrical Controls:** Specified for at least 20 years of service life, ensuring long-term reliability and efficiency**.**

Funding and Timing

- Funding that has been previously committed for this project: $440,225
- A Scheduled outage is required for this project.
- Desired implementation year: first year spend 2022 with installation planned for 2025-2028.
- System Engineer: Steven Morris

Conceptual Estimate

Year	Loaded Cost	Description
2022	**$ 96,011**	51% dollars. Engineering and planning
2023	**$ 128,504**	51% dollars. Engineering and planning
2024	**$777,250**	51% dollars. Engineering and planning. Procurement and preparation for installation
2025	**$1,431,751**	51% dollars. Final design and installation
2026	**$2,182,915**	51% dollars. Installation
2027	**$2,182,915**	51% dollars. Installation
2028	**$2,512,316**	51% dollars. Installation
2029	**$25,500**	51% dollars. Monitoring, Post Maintenance testing, Documentation and Closeout

Total Cost: 51% dollars - $9,037,164. 100% dollars – $17,719,930

Asset Strategy Approval Comments

The Asset Strategy team recommends approving Option 3 - Partial Replacement for the governor systems at Ludington Pumped Storage Plant due to critical concerns about part obsolescence and dam safety.

Key Points Supporting Approval

1. **Mitigation of Obsolescence and Reliability Issues:**
    - **End-of-Life Components:** Critical components have reached their service life and are obsolete, significantly impacting system reliability and necessitating their replacement to avoid Unit availability.
2. **Enhancement of System Redundancy and Reliability:**
    - **Redundancy Improvements:** The introduction of redundancies and defense in depth will provide a failsafe operational setup, crucial for maintaining operational integrity.

This investment **is** included in the current electric rate case.

Amount set for Bridge year: $345,000

Amount set for test period: $424,000

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric supply		

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Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN001804	**2026**	**4**	**Literal**

Investment Name	Scenario
LPS - Intake Gate and Gate House Mechanical Refurbishment	**Draft**

Value Function	**Consumers Energy Value Function**

Intake gate controls are obsolete

Difficulty sourcing parts in the past, such as control power transformers

Rotary limit switch is difficult to adjust

Mag amp modules and master signal modules will not adjust to specified test values

Current difficulty sourcing a direct replacement for Unit 1's speed switch

A 2020 condition assessment by the OEM identified corrective actions

Rust / corrosion

Leaking gear box seals

Inadequate lighting (since replaced with LED)

Deteriorating holding brakes

Control panel deterioration and dew point condensation

Old hoist motor

Unit 6 drum and pinion gear damage

Investment Type	Generation	Planning Portfolio	Ludington
Facility	Ludington / Ludington		
Executive Summary	The LPS - Intake Gate and Gate House Mechanical Refurbishment project aims to address the obsolescence and deterioration of intake gate controls at the Ludington facility. Scope The project involves replacing instrumentation and controls on six intake gate hoists, including the main control panel, maintenance control station, gate position and cut-out coupling limit switches, gate tachometers and speed switches, control interlocks, holding brake and cut-out coupling solenoids. The goal is to maintain existing intake gate hoist control functionality, eliminate the need to bypass penstock prime interlock, update controls to state-of-the-industry standards for utility-grade hydropower applications, maintain output of critical operating parameters to the plant's DAS/DCS, maintain plant-based emergency lower initiation, and test functional controls fully, including emergency lower functions, in a way that minimizes consequences of failure during testing. Objectives Restore reliability to the intake gate emergency lower function Ensure safe and reliable normal intake gate control function Avoid tie to moving target outages Recommended Alternative The planner recommends refurbishing the intake gate and gate hoist. The 2025 authorized budget will be used to issue RFI to hoist vendors to gather information on current controls upgrade offerings, then rewrite the purchase specification and issue a new RFP for the revised scope of work. The controls upgrades and testing will be implemented from 2027 to 2029 during unit periodic outages, with a total cost of $1,167k 51% CE share each of those years. Model Assumptions: The project assumes a general scenario of a 7-month long forced outage with a 10% probability of occurrence over the next 5 years. The potential capacity losses in the event of a 7-month single unit forced shutdown have been calculated at $20,368,403. The calculations were made using a conservative calculator provided by the capacity forecast team, with a CONE value of $130,930.		
Last Approver		Approval Date	

Investment Overview

Project Details	Environmental Justice Area	No
	Estimate Class	Class 4
	Rate Case Mapping	Pumped Storage
	EPM Managed	Yes
	Outage Type	Unit - Plant
	Scope	Replace instrumentation and controls on six intake gate hoists Main control panel Maintenance control station Gate position and cut-out coupling limit switches Gate tachometers and speed switches Control interlocks Holding brake and cut-out coupling solenoids Maintain existing intake gate hoist control functionality Eliminate need to bypass penstock prime interlock Update with state-of-the-industry controls for utility grade hydropower applications Maintain output of critical operating parameters to the plant's DAS/DCS Maintain plant-based emergency lower initiation Test functional controls fully, including emergency lower functions, in a way that minimizes consequences of failure during testing

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Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN001804	**2026**	**4**	**Literal**

Investment Name	Scenario
LPS - Intake Gate and Gate House Mechanical Refurbishment	**Draft**

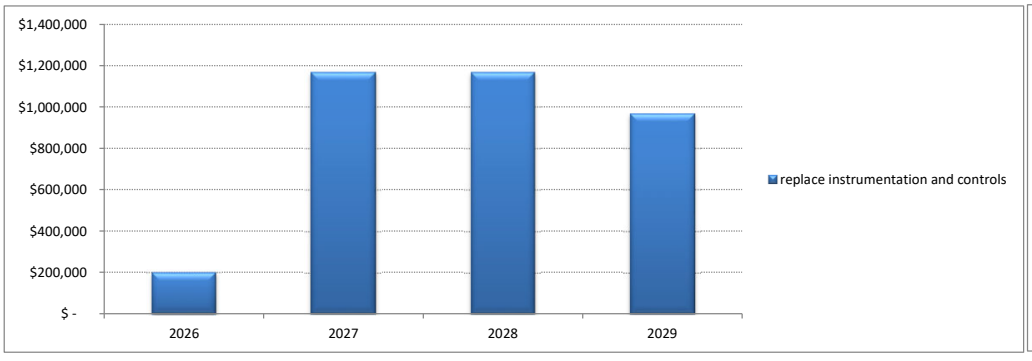
Value Function	**Consumers Energy Value Function**

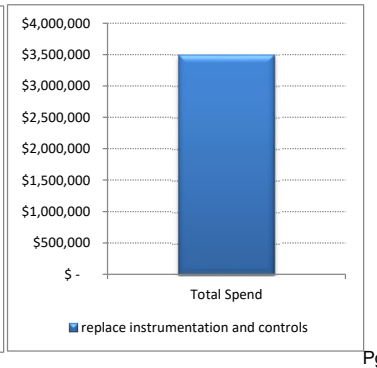
	Objectives	Mitigate forced shutdown risk Restore reliability to the intake gate emergency lower function Safe and reliable normal intake gate control function Avoid tie to moving target outages
	Planner Recommended Alternative	refurbish intake gate and gate hoist. Use 2025 authorized budget to issue RFI to hoist vendors to gather information on current controls upgrade offerings, then rewrite purchase specification and issue new RFP for revised scope of work $125k 51% CE share Implement controls upgrades and testing from 2027 to 2029 during unit periodic outages $1,167k 51% CE share each of those years, so no LTFP change in 2027 and 2028 while 2026 pushes to 2029
	Assumptions	a 7-month long forced outage scenario will be assumed if nothing is done and the control system fails to operate when called upon during an emergency. A 10% probability of occurrence over the next 5 years will be assumed for this case based on recent operational history. This equates to a little over 2% per year. 3% will be used due to software limitations. We experienced a Unit 1 overspeed in December. An emergency lower in that instance may have avoided the five months of outage and $1.6M (and rising) in cost that we're currently incurring. Overall a total risk of $15M-$50M will be assumed at a 3% chance of realizing. This includes both cost of repairs as well as capacity losses from a postulated 7-month single unit forced outage. Potential Capacity losses in the event of a 7-month single unit forced shutdown have been calculated at $20,368,403. The calculations were made using a conservative calculator provided by the capacity forecast team. Three-year impact on Capacity revenue is included in this number. The CONE value used for this model is $130,930. 75% of CONE was used for the calculations as customary.
Alternative Details	replace instrumentation and controls	eplace instrumentation and controls on six intake gate hoists Main control panel Maintenance control station Gate position and cut-out coupling limit switches Gate tachometers and speed switches Control interlocks Holding brake and cut-out coupling solenoids Maintain existing intake gate hoist control functionality Eliminate need to bypass penstock prime interlock Update with state-of-the-industry controls for utility grade hydropower applications Maintain output of critical operating parameters to the plant's DAS/DCS Maintain plant-based emergency lower initiation Test functional controls fully, including emergency lower functions, in a way that minimizes consequences of failure during testing

Alternative Spend Profile

Name	Status			Total Spend	Alternative Start Date
replace instrumentation and controls	Recommended			$ 3,499,833	1/1/2026

Name	Status	2026	2027	2028	2029
replace instrumentation and controls	Recommended	$ 200,000	$ 1,166,611	$ 1,166,611	$ 966,611





Concept Approval Internal Report

Investment Code	Report Start Year	Number of Years	Currency Scale
GEN001804	**2026**	**4**	**Literal**

Investment Name	Scenario
LPS - Intake Gate and Gate House Mechanical Refurbishment	**Draft**

Value Function: **Consumers Energy Value Function**

Forecasts - Draft (replace instrumentation and controls)

Account Type	2026	2027	2028	2029
Capital	$ 180,000	$ 1,049,950	$ 1,049,950	$ 869,950
Cost Of Removal	$ 20,000	$ 116,661	$ 116,661	$ 96,661
O&M	$ -	$ -	$ -	$ -

Concept Approval

Ludington Station Power Transformer Replacement

Date: 04/03/2025

Prepared by: Paul Ohep



Figure 1. Ludington pumped storage station power transformers.

Executive Summary

The Ludington Pumped Storage (LPS) facility, facing challenges with its aging Station Power Transformers (SPTs) that have been operational for over 50 years, requires a critical upgrade. These transformers are integral for stepping down voltage levels for efficient power distribution, and their current state poses significant operational and safety risks.

Selected Option: Replacement of SPTs 2 and 22 in 2026, SPTs 1 and 11 in 2028 and SPTs 3 and 33 in 2030.

Financial Implications: The total cost of the project is $9,411,764 (100% dollars), with Consumers Energy covering 51% ($4,800,000). This investment is deemed strategically sound, considering the long-term benefits and the need to mitigate risks associated with the current aging infrastructure.

Project Benefits:

- **Safety and Reliability:** Reducing the probability of transformer failures, which can cause operational disruptions and pose safety hazards.
- **Modernization:** Updating auxiliary components to current standards, enhancing functionality and compliance.
- **Strategic Outage Planning:** Replacement work scheduled during planned outages taking advantage of other planned work that will allow transformer replacements, minimizing operational impact, and avoiding additional capacity value losses.

Strategic Justification: This proactive and strategic replacement is crucial for ensuring continuous power generation at the LPS facility. The project addresses immediate safety and operational concerns.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	51% dollars - $4,800,000. 100% dollars – $9,411,764

Proposed Start Implementation Year and Duration

First year spend: 2025

Installation schedule:

2026: SPA2, SPA22

2028: SPA1, SPA11

2030: SPA3, SPA33

Problem Description

At the Ludington Pumped Storage (LPS) facility, the existing Station Power Transformers (SPTs) have been operational since the site's inception and are now presenting critical operational challenges. These SPTs, which include Transformers 1, 2, 3 (20kV/4160V) and Transformers 11, 22, 33 (4160V/480V), are responsible for stepping down 20kV to 4160V and 480V power systems to power in-house loads.

Current Status and Issues

- **Minimal Maintenance**: Due to the site's critical load demands, the SPTs have historically undergone minimal maintenance.
- **Aging Equipment**: The current transformers are not expected to last another decade in their current condition.
- **Inspection Findings**: Recent inspections by a reputable electrical contractor revealed that some transformers are in "marginal" condition, with STA2 specifically needing replacement as soon as practical.

Key Findings from 2021 STA2 Inspection Report

- **Overall Health**: Marginal
- **Electrical Evaluation**:
    - The transformer's electrical test results for the winding were acceptable for continued operation.
    - The “Doble Frank” evaluation system judged the CH (Core to High voltage), CL (Core to Low voltage), and CHL (Core to High and Low voltage) as “deteriorated” and “investigate” when compared to a 0.5% power factor maximum. These metrics relate to the insulation health of the transformer, with higher power factor values indicating deteriorated insulation.
    - The power factors have all increased since the previous 2019 tests, indicating a downward trend in the transformer's health.
    - HV bushings are new and tested well, but flagged as "investigate" due to differences in test data from the old type U bushings.
    - LV bushing tests were satisfactory.
    - The oil tested at 30.9kV for the D1816 1mm test, which is above the 23kV minimum acceptance, but the oil power factor has increased since 2019.

Electrical Evaluation Recommendations

- The overall power factor tests and oil power factor tests indicate a declining trend in the health of the insulation of this transformer.

- Further lab dissolved gas analysis (DGA) sampling of the transformer is recommended to further validate and perhaps quantify a declining trend in the health of the insulation of the transformer.
- Due to the criticality, age, and test results of this transformer, regular testing, evaluation of spare transformer availability, and future replacement plans should be considered.

Additional Considerations

- **Similar Transformers**: The inspection reports for STA1 showed better results, but these transformers are the same model and vintage as STA2, with similar failure mechanisms and operational history.
- **Replacement Timeline**: According to the 2021 inspection results conducted by an external vendor, Sub Metro, which identified adverse data trends, Consumer's Energy site engineering recommends that STA2 be replaced within five years to prevent operational issues and potential capacity losses.
- **Predicting Failure**: Transformer failure is difficult to predict, but the consensus is that the transformers should last a couple more years. Accurate trending would require many data points, which are currently unavailable.
- **Replacement Challenges**: The station transformers are of an unusual voltage/size/configuration, making replacements hard to find. The last estimated lead time for procurement was 24 months, expected to increase.
- **Obsolete Design**: The general design of the transformers and auxiliaries has been obsolete for years, and LPS lacks any spare 4160V or 480V SPTs onsite.
- **Operational Risks**: SPT failure could be violent, posing collateral damage risks to other equipment and a safety hazard to personnel.
- **Unreliable Transformers**: Despite their light loading over the years, the transformers are increasingly unreliable. Replacement components are challenging to acquire due to obsolescence, and there is a lack of confidence in their ability to operate reliably for another ten years. Lead time for a replacement could be up to 24 months.

Figure 2 below (next page) shows station transformers control circuit components, gauges/temperature trip devices and cooling fan controls/power poor material condition. These components have been the source of numerous plant DC bus grounds. Replacement components are difficult or impossible to obtain due to obsolescence.

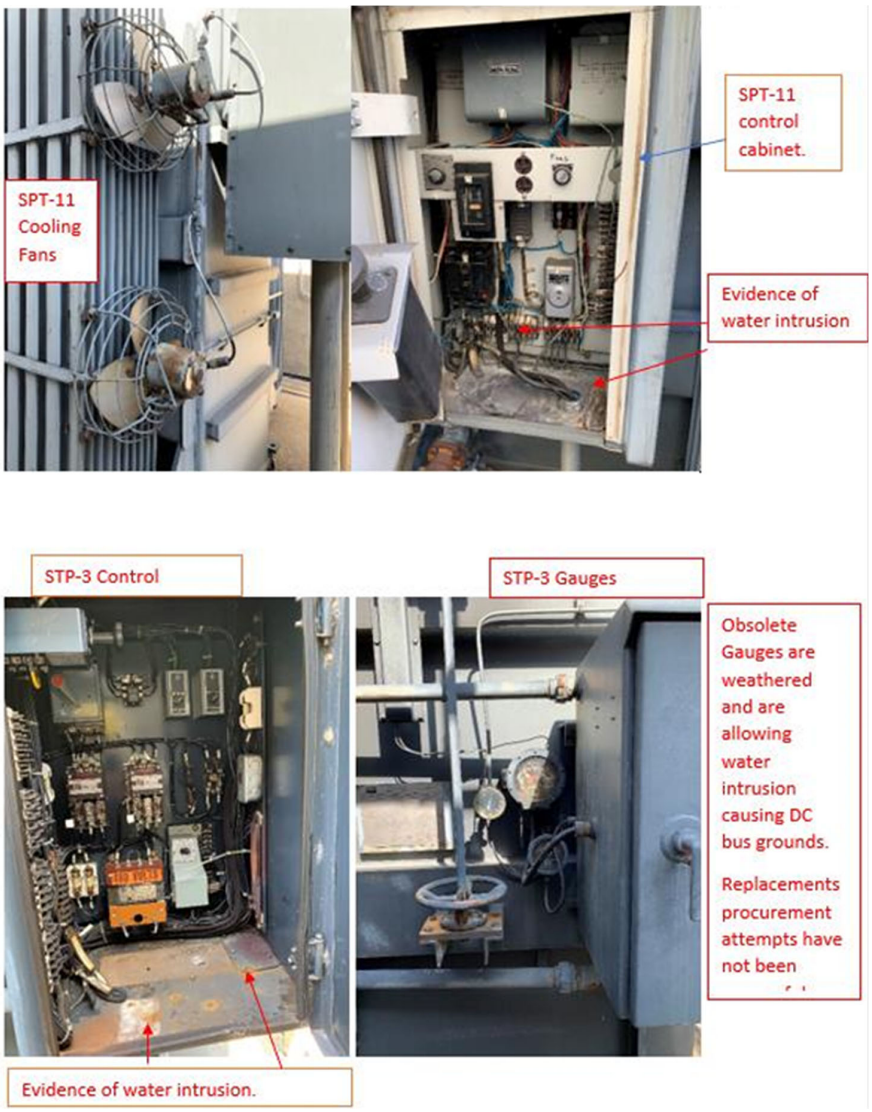


Figure 2. control circuit components

Alternative Solutions/Alternatives Considered

1. Do Nothing Top – cost $2.68M per failure

The "Do Nothing" approach involves continuing the operation of the Ludington Pumped Storage (LPS) facility without replacing the Station Power Transformers (SPTs). This option maintains the status quo, where the SPTs, which are original to the site and have been in service for over 50 years, continue to operate under the existing conditions.

Risks and Consequences:

1. **Increased Risk of SPT Failure:** As the transformers age, the risk of failure that would cause the unit to trip offline increases by 10% annually.
2. **Mandatory Time Between (MTB) Outages:** In the event of a transformer failure, an MTB outage of at least 7 days is required to isolate the SPTs. This results in operational disruptions and potential loss of generation capacity.
3. **Collateral Damage Costs:** A failure in one of the SPTs could be catastrophic, potentially causing collateral damage to other equipment at the site, which would incur additional repair costs.
4. **Replacement Costs Post-Failure:** If a transformer fails, the cost to replace it is estimated at $2 million, which is a significant expense in addition to the lost revenue and collateral damage costs.
5. **Loss of potential capacity revenue:** In the event of a transformer failure leading to an unplanned outage, Ludington Pumped Storage (LPS) could face significant losses in potential capacity revenue. Such an outage would necessitate taking two units offline for a week to isolate the malfunctioning transformer. The calculation of potential capacity value losses in this scenario includes:

    1. Zonal Resource Credits (ZRCs): The average ZRCs for two LPS units combines are 364.9. ZRCs represent the accredited capacity credits that a power generation unit contributes to the grid, used by grid operators like the Midcontinent Independent System Operator (MISO) for capacity planning and reliability.
    2. Cost of New Entry (CONE): The CONE value, set at $130,930, is a benchmark figure used by MISO to estimate the cost of bringing a new power plant online. It represents the per-day cost and is a critical component in calculating capacity market payments. For capacity calculations, 75% of the CONE value will be used ($98,198).
    3. Calculation of Lost Revenue: The potential loss in capacity value was determined using a calculator provided by the capacity forecast analysis department. This calculation is intentionally conservative (skewed towards less favorable outcomes) and does not fully incorporate all market dynamics relevant to the operation of the Ludington pumped storage station. The total

estimated potential capacity losses, due to having two units offline for 7 days, amount to $677,966.

I. Capacity lost revenue calculation basis:
The estimated capacity revenue loss of $677,966 was calculated using the standardized capacity calculator developed by the Capacity Forecast Analysis team. This calculator follows MISO guidelines and uses a two-step methodology based on outage duration and timing.

For this case, two Ludington units were offline for 7 days during the planning year. Because the outage lasted fewer than 31 days, the calculator applies a simplified loss estimation:

Lost Zonal Resource Credits (ZRCs) were calculated based on the outage duration as a fraction of the year and adjusted using the seasonal accredited capacity derate.

The lost ZRCs were then converted into dollar impact using the formula:
Lost ZRCs × 0.75 × CONE (Cost of New Entry)

The 0.75 factor is a standard adjustment applied when outages are ≤31 days or not in the planning year, representing a conservative revenue estimate.

The CONE value used was $130,990, with 75% of CONE applied per standard practice.

Pros to doing nothing:

- **Lower Immediate Expenditure:** This option involves the lowest upfront costs compared to undertaking a replacement project.
- **Avoidance of Immediate Project Execution:** Delays the need for immediate action and resource allocation for transformer replacement.

Cons to doing nothing:

- **Unplanned Outages and Associated Costs:** The facility must be prepared for unplanned outages with a minimum duration of 7 days to isolate a failed transformer, leading to significant revenue loss, potential capacity value and operational disruptions.
- **Increased Operational and Maintenance Challenges:** The facility will likely face more frequent failures and operational issues as the transformers continue to age and deteriorate.

- **Inevitable Lifecycle Management and Replacement:** The replacement of these transformers will eventually become necessary and delaying this can lead to more complex and costly interventions.
- **Safety Hazards:** A failure of an SPT could be violent, posing risks to other equipment and, more critically, to personnel safety.

2. Replace all 6 Station Power Transformers over 5 years – Internal estimate of $4,800,000 (51% Dollars)

Project Overview: This option involves the complete replacement of the existing Station Power Transformers (SPTs) at Ludington Pumped Storage (LPS). The project focuses on addressing the issues due to the aging transformers, which are over 50 years old and increasingly prone to failure.

Key Benefits and Implementation Strategy:

1. **Increased Equipment Lifespan:** Operating at the correct voltage will significantly extend the lifespan of the site equipment.
2. **Life Expectancy Alignment with Site's Operational Period:** The new transformers will have a life expectancy that matches the site's anticipated operational lifespan, ensuring consistent and reliable support.
3. **Routine Maintenance Without Risk:** The updated SPTs will allow for routine maintenance without the risk of equipment damage, crucial for preventing unexpected failures.
4. **Reduced Failure Probability:** Replacing the aging transformers will significantly lower the likelihood of unexpected failures, enhancing overall reliability.
5. **Mitigation of Spare Transformer Risks:** This project addresses the current risk associated with the lack of spare SPTs at LPS.
6. **Restored Tap-Changing Capability:** The new transformers will enable tap changing, essential for voltage regulation, which is currently hindered due to the aging SPTs.

Strategic Outage Planning:

- The replacement of all six transformers will be executed during planned outages over a period of 3 years. This phased approach ensures that there will not be additional capacity value losses incurred due to the project.

Cost Breakdown:

- The total cost for this replacement is $7,450,980, with CEC covering 51% of this amount, equating to $3,800,000. This investment includes the procurement and installation of new transformers and associated project management costs.

3. Replace/Repair Specific Components of STP– internal estimate of $2,151,855 (100% dollars), $1,097,446 (51% dollars)

Option 3 involves replacing or repairing specific components of the Station Power Transformers (STPs) at the Ludington Pumped Storage (LPS) facility. This approach focuses on addressing the most critical components currently failing or at risk of failure.

Key Aspects of the Project:

1. **Implementation in Phases:** The replacement or repair work will be carried out in three separate planned outages, each estimated to last 7 days. The total downtime for all outages is factored into the cost calculation.
2. **Cost Calculation:** The potential capacity value loss for each 7-day, 2-unit outage is calculated at $667,285, similar to Option 1. With three outages needed for this option, this totals $2,001,855. Additionally, $150,000 is estimated for parts and labor, bringing the total project cost to an estimated $2,151,855.
3. **Limited Scope:** This option focuses on the replacement or repair of only certain components of the STPs, not a complete overhaul or replacement of the transformers.

Pros:

- **Lower Equipment Cost:** The cost for parts and labor in this option is lower than the complete replacement of the STPs as proposed in Option 2.
- **Targeted Repairs:** Repairs are focused on the most critical components, potentially extending the operational life of these parts.

Cons:

- **Difficulty in Sourcing Components:** Replacement components are difficult, if not impossible, to find due to the obsolescence of the transformers.
- **Long Lead Times:** Procuring components that are available may have long lead times.
- **Limited Scope of Repairs:** Internal components and windings would not be repaired or replaced, which does not prolong the overall life of the transformer windings.
- **Persistent Low Voltage Issue:** Voltage at the site would remain low, continuing to affect equipment lifespan.
- **Ongoing Operational and Maintenance Challenges:** Even with repairs, operational and maintenance issues are likely to arise due to more failures.
- **Inevitable Lifecycle Management and Replacement:** Complete lifecycle management and eventual replacement of the STPs will still be required in the near future.

- **Safety Hazards:** The potential for violent failure of an STP continues, posing risks to other equipment and personnel safety.
- **Multiple Outages Required:** Several outages, each with an uncertain duration, will be required to perform the necessary work.

Recommended Alternative: Option 2, Replace Station Power Transformers – Internal estimate of $4,800,000 (51% Dollars)

Primary Advantages and Project Objectives:

1. **Voltage Stabilization:** Correcting the existing voltage droop, Option 2 ensures the Ludington Pumped Storage (LPS) operates at optimal voltage levels, crucial for efficient power generation.
2. **Restored Tap-Changing Capability:** The new transformers will enable tap changing, essential for voltage regulation, which is currently hindered due to the aging SPTs.
3. **Life Expectancy Alignment:** The transformers will match the LPS site's operational period, ensuring reliable power supply for the long term.
4. **Preventative Maintenance Enhancement:** The replacement facilitates preventative maintenance without risking significant damage, enhancing overall facility reliability and safety.
5. **Updated Auxiliaries:** Incorporating modern standards, the auxiliary components of the new transformers ensure improved functionality and compliance.
6. **Minimized Operational Impact:** By scheduling replacements during planned outages, operational disruptions and associated revenue losses are minimized, making it the most efficient option in terms of outage duration.
7. **Safety and Reliability:** This proactive replacement mitigates risks of violent failures, which could cause collateral damage and pose safety hazards. Replacing over 50-year-old critical electrical equipment preemptively avoids random failures and addresses the lack of spare transformers on site.

Option 2 is a comprehensive solution that enhances operational efficiency, safety, and future readiness of the Ludington Pumped Storage facility. This strategic investment in modern, efficient transformers significantly reduces unforeseen failure risks, aligning the facility with current safety and performance standards.

Scope of Work

Procure and replace all 6 SPTs with new to suit size and configuration in current LPS footprint:

1. Provide specification for RFQs and acquire quotes for replacement units 2 years in advance of expected outages of execution.
2. Re-align with asset management and stakeholders for funding and schedule requirements and authorization to proceed.
3. Award contracts, begin planning and procurement of replacement units, verify outages for installation are adequate.
4. Install replacement units during outages of opportunity once delivered.

Funding and Timing

- Funding that has been previously committed for this project: $0
- A Scheduled outage is required for this project.
- System Engineer: Anthony C. Szostak Jr

Conceptual Estimate

Year	Loaded Cost	Description
2025	$150,000	51% dollars. Design work
2026	$1,200,000	51% dollars. First round of installs
2027	$1,000,000	51% dollars. Second round of installs
2028	$1,200,000	51% dollars. Second round of installs
2029	$200,000	51% dollars. Design work
2030	$1,000,000	51% dollars. Third round of installs
2031	$50,000	51% dollars. Closeout

Total Cost: 51% dollars - $4,800,000. 100% dollars – $9,411,764

Asset Strategy Approval Comments

The Asset Strategy Group approves Option 2 for its cost-effectiveness and alignment with our budgetary efficiency goals. This investment in replacing the Station Power Transformers at Ludington Pumped Storage ensures operational reliability and safety while optimizing long-term financial outlay. Executing the replacement during planned outages minimizes disruptions and associated costs, demonstrating fiscal responsibility. OBJ

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-22070
Exhibit No.: A-236 (MEW-43)
Page: 1 of 1
Witness: MEWittbrodt
Date: June 2026

2025 Change Log Summary broke/fix Emergent Issues

Description	Cost (000's)	Details	Site
Karn ICS Additional Costs	$ 3,200	Estimated additional spending needed for Karn, POs written broke/fix GSU failure	Karn
Karn Fire & Transformer Move - Emergent Changelog	$ 2,000	HLI to Transport (1) Transformer by rail from West Olive, MI to Essexville, MI. -$1.2M	Karn
Covert HEPS & FAC - Emergent Changelog	$ 1,182	The team has evaluated whether these are “must do” vs potential deferral repairs. The plan includes the must do repairs. This project needs immediate approval to mitigate outage extensions.	CGS
Emergent - LPS - Unit 1 outage	$ 561	Emergent - Est. repair costs for the LPS Unit#1 Forced Outage due to a Runaway event on 12/4/24.	LPS
Gen Ops - CGS HEPS/FAC Emergent Request #2	$ 535	This is a true up to the original request for Covert HEPS discovery/repairs and since this is a significant increase we would like BUG and VP approval to proceed. We are building an offsetting strategy of downlevers that we will bring to the April change log to offset these requests. This request is for $535k of additional O&M to finish the repairs.	CGS
JGS MM Base Outage	$ 325	emergent repair to fire protection header- safety issue.	JGS
Gen Ops- Karn GSU Fire	$ 300	Initial ask to fund ICS at Karn for O&M	Karn
Covert - 2A Circ Pump Emergent	$ 285	Emergent approval via email on 10/7/2025 - broke fix	
JGS - Cooling Tower Repairs	$ 271	This is 1st & 2nd quarter immediate issues identified during the ICT level 2 inspections in the fall 2024 outage. Materials is being purchased 4th quarter 2024 and fall outage work scope will be done thru levers/flex or change log processes	JGS
EMERGENT - Covert Unit 1 Steam Turbine Valve Repair	$ 250	A recent inspection at Covert identified a crack on a high-pressure control valve bushing. These can become a very serious or dangerous issue and definitely take the unit offline when it fails. We need to address this issue immediately at our earliest outage of opportunity which is this fall to avoid safety and forced outage issues.	CGS
Emergent - Foote Downstream Concrete Repair	$ 205	Emergent - The hydro team requires $205k of O&M to finish this work. In our reviews we found out this project has been progressing and these are actual costs. We explored multiple options including stoppage of work. The decision to proceed now will save the customer approx. $30k on demob/mob of the crane. The majority of the work is completed.	Hydro
Gen Ops-Karn 4 Burner Oil Pump Leak PT-11178	$ 180	Broke/fix	Karn
Karn 4 FD Missing	$ 175	Structural issues inside the duct that need to be repaired	
PP-10219 Covert Fall Outage	$ 170	Additional funding needed to address issues at the Covert Generating Station during the fall outage.	CGS
JGS HRSG 7 Perforated Plate Distribution Wall failed	$ 150	Broke/fix in fall outage	JGS
JGS Duct Burner Isolation Valves	$ 140	Funding to replace the duct burner isolation valves on the HRSGs during the Fall outage – ahead of the originally planned Spring 2026 execution. We are continuing to experience valve failures in the field resulting in significant losses in power production. Our recent GVTC testing had poor results which will have significant impact to our 2026 capabilities. We are requesting $140k of O&M (cost plus expediting) to purchase replacements for all the failed isolation valves along with remaining carbon steel valves that are at risk of failing	JGS
Ludington Fish Barrier Net-Installation, Cleaning, Repairs & Removal	$ 128	Part of it is HDR, looks like their costs are about $10k more per month with their new contract. Part of it is UCC being more attentive about staffing this project. UCC's contract ends November 30, no new contract yet for December's rates	LPS
ZGS HRSG 2A & 2B Heat Trace Repair	$ 120	NERC required winterization	
Mio Spillway hollow chamber leakage sealing	$ 110	Leakage has been known, 2024 dive inspection found source. Need to repair to prevent sand ballast washout from the hollow chamber - dam stability	Hydro
Karn Forced Outage	$ 110	Broke/fix - Request of funding. Site does not currently have funding for forced outages	Karn
Gen Ops- Ausable River Queen Clean up	$ 100	Cleanup costs related to the Ausable River Queen incident. USEPA holding us accountable on some of the invoices. Plan is to recoup money from owners but unsure of timeline and plan.	Hydro
Karn 3&4 Louver Repairs	$ 100	This request only covers the scaffold costs. Anticipate utilizing plant resources to complete the work. There are approximately 10 to 12 louvers per unit that are inoperable, some stuck open allowing cold air to get into the plant during the winter. This caused freezing issues last winter affecting unit availability and even forced a must run condition when not necessarily economic for our customers. These issues occurred despite plant heating in service. Significant scaffolding over open areas (not accessible with lifts or JLGs) is required.	Karn
Karn Road Repairs	$ 100	Approved emergent via email on 11/6 failed roadway from previous water main leak	
Covert - Ammonia Fan Rebuilds	$ 93	moving 2025 funds to O&M for fan rebuild of the old design.	CGS
Covert U2 EE-OO Expansion Joint	$ 85	Approved emergent via email on 11/7	
Croton Unit 1 Generator	$ 80	There is a broken bus bar between the collector ring and the rotor poles on the Croton Unit 1 Generator.	Hydro
JGS - 480V WavePro Breaker Replacements	$ 75	Work was delayed in 2024 and a portion of the initial funding was utilized to address cubicle modifications due to an identified arc flash risk. These requested funds are to complete the rebuild and installation of the remaining half (quantity: 17) of the 480V breakers.	JGS
ZGS Outage Base	$ 70	HRSG Leaking penetrations seals plus insulation	
CGS - 1. Cable Vault Tray Supports – Failed	$ 68	This has been entered as a threat to generation (cable tray failure could compromise conductors and result in unit trip) – seeking planning and funding in 2025	CGS
CGS HRSG U3 Seals and Insulation replacement request	$ 64	Dome of the expansion joints installed last fall have failed. Worked with IAFD company to share cost of replacement. This is for seals and insulation.	
NEW - Covert Circ Pump Vibration Analysis	$ 62	The analysis being performed is highly technical and required to determine the root cause of our historical vibration issues with the pumps at Covert.	CGS
Karn B Aux Boiler FD Fan Shaft/Bearing Repair	$ 60	Karn B Aux Boiler FD Fan Shaft/Bearing Repair. Emergent Broke/Fix work.	Karn
LPS Unit 1 South Trash Rack Repairs	$ 60	Funding, time, and resources for this trash rack repair were used to offset the emergent repair of the Unit 3 south trash rack. Having repaired the Unit 1 south and Unit 3 south trash rack in 2024, we have a better idea of the level of effort needed to effect these repairs.	LPS
Hardy spill tube aeration flow meters and lighting	$ 55	•Modify the lighting circuit that lights the caverns by spill tubes 2 &3 to keep it out of the water running down the wall that has faulted that circuit. This is more a safety issue, there is no light down there but your flashlight when trying to complete maintenance or daily operation duties in those areas.	Hydro
LPS - Unit 6 shaft seal failure	$ 51	Not part of corrective action lawsuit	
Mio Spillway Hollow Chamber repair	$ 50	The divers discovered additional work needed. If work is completed now it would save remobilizing the contractor. Risk of not doing the work is loss of fill(washout) and destabilizing the powerhouse/spillway.	Hydro
JGS - LM Filter House Drift Eliminator Repl and Cooling Coil Cleaning	$ 50	The existing drift eliminators in the LM6000 filter houses are the original ones and are brittle and falling apart. Recent cooling coil performance testing by EPTS identified an average cooling coil efficiency loss of 15.9% from expected which is a reduction of total plant output of 2.85 MW under summer GVTC conditions.	JGS
Covert - auxiliary boiler leak repair	$ 46	EMERGENT approved email 8/11/2025	CGS
LPS IPB Inspection and Maintenance	$ 46	The IPB on MTB1 needs to be cleaned. This was discovered from the MTB1 inspection.	LPS
PP-10218 Covert U 3 HP Steam Leak Repair	$ 45	True-up of project with funds from the NERC Relay/DC Testing Compliance & Capacity Factor Projects.	CGS
LPS environmental	$ 43	Environmental allocation came in higher than planned in 2025	LPS
LPS - Generator Air Cooler Cleaning (6 Coolers)	$ 43	Generator Air cooler cleaning for coolers that were recently replaced	
Karn 3 & 4 - FW Heater safety relief testing & setting	$ 40	Components need testing; not suspected to have been inspected before	Karn
Ludington Fish Barrier Net-Installation, Cleaning, Repairs & Removal	$ 36	Run rate for Barrier net install was higher than planned	LPS
B-PH-00168 LPS Unit 3 South Trash Rack Dive and Repair	$ 36	Based on an inspection of the LPS Unit 3 south trash rack on 8/29, additional funding is needed to perform emergent repairs and a dive to remove debris from the sill slot during the Unit 3 pumping outage this fall.	LPS
LPS Unit #6 Intake Gate Drum Alignment	$ 28	The U6 intake gate drum alignment work is based on the system condition assessment by Stantec and visual inspections completed by CE team for the drum gear and drive. It was originally being considered under the Capital project for the Intake Gate Refurbish project, but this mechanical scope is repair only and alignment and so we are completing the work before we start the project.	
LPS - Observation Well Inspection and/or cleaning	$ 23	Elevated levels in the Obervation wells, Video Inspection needed and potential for a cleaning	
Covert - Site Diesel Generators– air inlet louver drive motors failed for both engines	$ 20	Louvers are supposed to open automatically upon engine start to ensure sufficient air for the engine and turbo chargers	CGS
Gen Ops - LPS intake gate slot bubbler orifices	$ 13	The intake gate slot bubbler orifices need to be replaced.	LPS
Gen Ops - LPS - Unit 2 Penstock Intake Repair	$ 10	Error in calculation going from 100% to 51% in previous changelog, did not request enough funding.	LPS
2025 TOTALS =	$ 12,049		