November 10, 2025

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917

RE: Case No. U-21870 – 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.

Dear Ms. Felice:

Enclosed for electronic filing in the above captioned case please find **Consumers Energy Company's Official Exhibits** as admitted into evidence during the hearing in this case. Also attached is a Proof of Service.

Confidential versions of the following exhibits will be filed under seal with the MPSC.

A-20 (SHB-5)	A-58 (TPC-5)	A-65 (TPC-12)
A-21 (SHB-6)	A-59 (TPC-6)	A-69 (LMC-8)
A-23 (SHB-8) Revised	A-61 (TPC-8)	A-70 (LMC-9)
A-55 (TPC-2)	A-62 (TPC-9)	A-100 (KKG-4)
A-56 (TPC-3)	A-63 (TPC-10)	A-174 (SES-5)
A-57 (TPC-4)	A-64 (TPC-11)	

Sincerely,

Gary A. Gensch Jr.
Phone: 517-788-0698
Email: gary.genschjr@cmsenergy.com

cc: Parties per Attachment 1 to Proof of Service

Consumers Energy Company

Electric Rate Case No. U-21870

Index of Exhibits - A# Order

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186	A-123	-	Kelly, Michael P	MPK-13	Summary of Actual & Projected Electric & Common O&M Expenses – Operations and Engineering
187	A-124	-	Kelly, Michael P	MPK-14	Summary of 5yr Historical O&M Expenses
188	A-125	-	Kelly, Michael P	MPK-15	Summary of Actual & Projected Electric & Common O&M Expenses – O&M Programs, part 1
189	A-126	-	Kelly, Michael P	MPK-16	Summary of Actual & Projected O&M Programs, part
190	A-127	-	Kelly, Michael P	MPK-17	Summary of Actual & Projected O&M Expenses Cost Splits
191	A-128	-	Kelly, Michael P	MPK-18	Summary of O&M Expenses Projected Using Inflation
192	A-129	-	Kelly, Michael P	MPK-19	Amended Reliability Roadmap
193	A-130	-	Kelly, Michael P	MPK-20	2020-2024 Distribution Unit Costs
194	A-131	-	Kelly, Michael P	MPK-21	2023 Electric System Loss Study Report
195	A-132	-	Kelly, Michael P	MPK-22	Mitigating Wildfire Risk in Consumers Energy's Service Territory (2025-2029)
196	A-133	-	Kelly, Michael P	MPK-23	Advanced Metering Infrastructure Metrics and Elements
197	A-134	-	Kelly, Michael P	MPK-24	Electric Distribution Summary of Actual & Projected Capital Expenditures per Rate Case Filing Requirements Attachment 11
198	A-135	-	Kelly, Michael P	MPK-25	Reliability Regression Analysis for Environmental Justice Communities
199	A-136	-	Kelly, Michael P	MPK-26	AMI Opt Out Charges
200	A-137	-	Kelly, Michael P	MPK-27	Environmental Justice Hosting Capacity Maps
201	A-138	-	Kelly, Michael P	MPK-28	Reliability and Disconnections Regression Analysis Overview and Observations
202	A-139	-	Koetje, Jon J	JJK-1	Karn Units 1&2 Decommissioning Plan Expenditures
203	A-140	-	Koetje, Jon J	JJK-2	Actual Coal Ash Disposal Plan Expenditures
204	A-141	-	Koetje, Jon J	JJK-3	JHC Decommissioning Plan Expenditures
205	A-142	-	McPhail, Scott A	SAM-1	Bridge Period Grid Automation Projects
206	A-143	-	McPhail, Scott A	SAM-2	Test Year Grid Automation Projects
207	A-144	-	McPhail, Scott A	SAM-3	Line Sensor Reliability Benefits
208	A-145	-	McPhail, Scott A	SAM-4	RAMP Reliability Benefits
209	A-146	-	McPhail, Scott A	SAM-5	Line Regulator Controller Upgrades BCA
210	A-147	-	McPhail, Scott A	SAM-6	NOVA TS Comms Reliability Benefits
211	A-148	-	McPhail, Scott A	SAM-7	Peer-Peer Schemes Reliability Benefits
212	A-149	-	McPhail, Scott A	SAM-8	Recloser Modernization Reliability Benefits
213	A-150	-	McPhail, Scott A	SAM-9	Supplemental Line Sensors Reliability Benefits
214	A-151	-	McPhail, Scott A	SAM-10	Metro Modernization Reliability Benefits
215	A-152	-	McPhail, Scott A	SAM-11	Distribution Asset Management BCA
216	A-153	-	McPhail, Scott A	SAM-12	FLISR EPRI Report
217	A-154	-	McPhail, Scott A	SAM-13	FLISR BCA
218	A-155	-	McPhail, Scott A	SAM-14	Weather Stations Reliability Benefits

219	A-156	-	Meschke, Ashley E	AEM-1	2024-2025 EICP Operational Goals
220	A-157	-	Meschke, Ashley E	AEM-2	2024 Customer Benefits: Employee Safety
221	A-158	-	Meschke, Ashley E	AEM-3	2024 Customer Benefits: Reliability
222	A-159	-	Meschke, Ashley E	AEM-4	2024 Customer Benefits: Culture Index – Reduced Employee Turnover
223	A-160	-	Metz, Megan L	MLM-1	Power Supply Cost Recovery Forecast for May 1, 2026 – April 30, 2027
224	A-161	-	Metz, Megan L	MLM-2	Consumers Energy Forecast – Energy Market Sales Revenue and Total Variable Expense
225	A-162	-	Metz, Megan L	MLM-3	Summary of PPA Changes from September 30, 2024 – February 1, 2025
226	A-163	-	Myers, Heidi J	HJM-1	Distribution Investment Recovery Mechanism - Annual Revenue Requirement
227	A-164	-	Myrom, Jeffrey A	JAM-2	Transportation Electrification Plan Deferred Asset Costs
228	A-165	-	Myrom, Jeffrey A	JAM-3	Transportation Electrification Plan Cost Benefit Analysis
229	A-166	-	Partlan, Jennifer M	JMP-1	Bridge Period LVD Project List
230	A-167	-	Partlan, Jennifer M	JMP-2	Test Year LVD Project List
231	A-168	-	Partlan, Jennifer M	JMP-3	Conservation Voltage Reduction Measurement and Verification Independent Assessment
232	A-169 Revised	-	Partlan, Jennifer M	JMP-4	Summary of 2023 and 2024 LVD Repetitive Outages Investment (Revised)
233	A-170 Revised	-	Stewart, Sara E	SES-1	Line Clearing O&M Expense (Revised)
234	A-171	-	Stewart, Sara E	SES-2	Projected LVD Tree-Caused Reliability Impacts of the Line Clearing Ramp-Up Plan
235	A-172	-	Stewart, Sara E	SES-3	2025 HVD Line Clearing Work Plan
236	A-173	-	Stewart, Sara E	SES-4	2025 LVD Line Clearing Work Plan
237	A-174	-	Stewart, Sara E	SES-5	Post-Work Review Supporting Documentation Examples (CONFIDENTIAL)
238	A-175	-	Stewart, Sara E	SES-6	Summary of O&M Expenses Projected Using Inflation
239	A-176	-	Stewart, Sara E	SES-7	Formal Optimization Analysis of Line Clearing Cycles
240	A-177	-	Stewart, Sara E	SES-8	Utility Vegetation Management in North America: Results from a 2019 Utility Forestry Census of Tree Activities and Operations
241	A-178	-	Tetrick, Caitlin M	CMT-1	Summary of Historical Year, Bridge Period, and Projected Test Year for Operations Resources – Electric LVD Workplan
242	A-179	-	Tetrick, Caitlin M	CMT-2	Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources – Electric HVD Workplan
243	A-180	-	VanBlarcum, Brian J	BJV-1	Development of the Property Tax Rate for the Test Year
244	A-181	-	VanBlarcum, Brian J	BJV-2	Amortization of Excess Deferred Federal Income Taxes for the Test Year and Tax Reform Regulatory Liability & Amortization
245	A-182	-	Gast, Alex M	AMG-3	Whole Home Optimization Demand Response pilot
246	A-183	-	Baker, Stacy H	SHB-12	Asset Refresh Program ("ARP")-Field Device Asset Management ("FDAM") and ARP-Workstation Asset Management ("WAM") New Purchases Four-Year Historical Average
247	A-184	-	Baker, Stacy H	SHB-13	Staff Audit Responses U21870-SA-CE-024 and U21870-SA-CE-090
248	A-185	-	Baker, Stacy H	SHB-14	Asset Refresh Program-Field Device Asset Management number of units/devices in place at the end of each year 2021, 2022, 2023, and 2024 including new purchases
249	A-186	-	Baker, Stacy H	SHB-15	Staff Audit Response U21870-SA-CE-080
250	A-187	-	Bleckman, Marc R	MRB-22	Company Revision to Staff's Exhibit S-4, Schedule D-1 Alternative

251	A-188	-	Bleckman, Marc R	MRB-23	Company Revision to Staff's Exhibit S-4, Schedule D-2 Alternative
252	A-189	-	Bleckman, Marc R	MRB-24	MPSC Staff's Answer to Consumers Energy's Fourth Discovery Request
253	A-190	-	Bleckman, Marc R	MRB-25	Attorney General's Answer to Consumers Energy's Third Discovery Request
254	A-191	-	Blumenstock, Richard T	RTB-13	Covert Generating Station Units 1 & 3 LTSA Extra Work
255	A-192	-	Blumenstock, Richard T	RTB-14	Ludington Pumped Storage Dike Load Center Replacement
256	A-193	-	Blumenstock, Richard T	RTB-15	Ludington Pumped Storage Oil Water Separator
257	A-194	-	Blumenstock, Richard T	RTB-16	Ludington Pumped Storage Pony Motor Rotor Cracking and Fretting
258	A-195	-	Blumenstock, Richard T	RTB-17	Ludington Pumped Storage Distributed Control System Control Relay Replacement
259	A-196	-	Blumenstock, Richard T	RTB-18	Ludington Pumped Storage Unit Governors
260	A-197	-	Blumenstock, Richard T	RTB-19	Ludington Pumped Storage Lower Penstock Expansion Joint Chamber Waterstop
261	A-198	-	Blumenstock, Richard T	RTB-20	Covert Generating Station spare Generator Step-Up ("GSU") transformer
262	A-199	-	Blumenstock, Richard T	RTB-21	Zeeland Generating Station Phase II Gas Turbine Advanced gas path replacement and axial fuel staging project
263	A-200	-	Blumenstock, Richard T	RTB-22	Zeeland Generating Station Phase I performance report
264	A-201	-	Blumenstock, Richard T	RTB-23	Emergent Reliability Investment for the years 2022 through 2025
265	~~A-202~~	-	~~Blumenstock, Richard T~~	~~RTB-24~~	~~Jackson Generating Station spare GSU transformer~~
266	~~A-203~~	-	~~Blumenstock, Richard T~~	~~RTB-25~~	~~Jackson Generating Station LM1-6 variable inlet guide vane~~
267	A-204	-	Blumenstock, Richard T	RTB-26	Year over Year Generation O&M Expense
268	A-205	-	Blumenstock, Richard T	RTB-27	Copperleaf Value Model Methodology
269	A-206	-	Bulkley, Ann E	AEB-2	Cost of Common Shareholder's Equity
270	A-207	-	Bulkley, Ann E	AEB-3	Work Papers AG-37B, AG-39A, and AG-39B
271	A-208 Revised	-	Daly, Patrick D	PDD-63	Adjusted Revenue Deficiency for the Projected 12-Month Period Ending April 30, 2027 (Revised)
272	A-209	-	Daly, Patrick D	PDD-64	Adjusted Rate Base for the Projected 12-Month Period Ending April 30, 2027
273	A-210	-	Daly, Patrick D	PDD-65	Adjusted Utility Plant for the Projected 12-Month Period Ending April 30, 2027
274	A-211	-	Daly, Patrick D	PDD-66	Capital Spending Reconciliation for the Projected 12-Month Period Ending April 30, 2027
275	A-212	-	Daly, Patrick D	PDD-67	Adjusted Working Capital for the Projected 12-Month Period Ending April 30, 2027
276	A-213 Revised	-	Daly, Patrick D	PDD-68	Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027 (Revised)
277	A-214 Revised	-	Daly, Patrick D	PDD-69	Reconciliation of Adjusted Net Operating Income for the Projected 12-Month Period Ending April 30, 2027 (Revised)
278	A-215	-	Daly, Patrick D	PDD-70	Adjusted Operations & Maintenance Expenses for the Projected 12-Month Period Ending April 30, 2027
279	A-216 Revised	-	Daly, Patrick D	PDD-71	Income Tax Effect of Interest for the Projected 12-Month Period Ending April 30, 2027 (Revised)
280	A-217 Revised	-	Daly, Patrick D	PDD-72	Interest Synchronization Adjustment for the Projected 12-Month Period Ending April 30, 2027 (Revised)

281	A-218	-	Hayward, Megan L	MLH-6	Discovery Response 21870-AG-CE-0466
282	A-219	-	Kelly, Michael P	MPK-29	Actual and Forecasted 2025 Capital and O&M Spending
283	A-220	-	Kelly, Michael P	MPK-30	Audit Response 21870-SA-CE-248
284	A-221	-	Kelly, Michael P	MPK-31	Discovery Response 21870-AG-CE-0514
285	A-222	-	Kelly, Michael P	MPK-32	Discovery Response 21870-AG-CE-0453
286	A-223	-	Myrom, Jeffrey A	JAM-4	Discovery Response 21870-MEIU-CE-0042
287	A-224	-	Myrom, Jeffrey A	JAM-5	Discovery Response 21870-MEIU-CE-0043
288	A-225	-	Partlan, Jennifer M	JMP-5	Discovery response 21870-ST-CE-0078
289	A-226	-	Partlan, Jennifer M	JMP-6	Example of LVD Concept Approval
290	A-227	-	Partlan, Jennifer M	JMP-7	Discovery response 21870-AB-CE-0712
291	A-228	-	VanBlarcum, Brian J	BJV-3	Workpaper WP-PDD-29
292	A-229	-	VanBlarcum, Brian J	BJV-4	Workpaper WP-PDD-36
293	A-230	-	Myrom, Jeffrey A	JAM-6	2025 TEP Annual Progress Report

Schedule: A-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Deficiency (Sufficiency)
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-1 (PDD-1)
Schedule: A-1
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) Source	(c) Total Amount	(d) Jurisdictional Amount
1	Rate base	Exhibit No.: A-2 (PDD-3)	14,288,124	14,241,328
2	Adjusted net operating income	Exhibit No.: A-3 (PDD-9)	829,498	833,578
3	Overall rate of return	Line 2 / Line 1	5.81%	5.85%
4	Required rate of return	Exhibit No.: A-4 (PDD-23)	5.86%	5.86%
5	Income requirements	Line 1 * Line 4	837,841	835,097
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	8,343	1,519
7	Revenue conversion factor	Exhibit No.: A-3 (PDD-10)	1.3381	1.3381
8	Revenue Deficiency (sufficiency)	Line 6 * Line 7	11,164	2,033

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Financial Basis
ELECTRIC RESULTS ONLY
($000)

Case No.: U-21870
Exhibit No.: A-1 (PDD-2)
Schedule: A-2

Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) 2020	(c) 2021	(d) 2022	(e) 2023	(f) 2024
				Calendar Year		
1	Operating revenues	4,372,177	4,957,857	5,419,082	4,745,364	5,061,475
2	Operating expenses	3,531,392	4,156,834	4,630,615	3,973,704	4,079,442
3	Pre-tax operating income	840,785	801,024	788,467	771,660	982,033
4	Income taxes	115,416	117,193	108,800	66,100	101,842
5	Net operating income	725,370	683,831	679,667	705,560	880,191
6	Other income and deductions	41,819	83,027	102,863	128,080	109,035
7	AFUDC	7,211	8,207	5,520	3,493	24,362
8	Interest charges	(202,399)	(193,601)	(206,904)	(273,930)	(319,881)
9	Preferred stock dividends	(1,111)	(1,081)	(1,078)	(1,040)	(1,008)
10	Net income available to common stockholders	570,889	580,383	580,068	562,163	692,699
11	Average common equity	5,806,036	6,260,365	6,372,772	6,607,356	6,893,776
12	Earned rate of return on common equity	9.83%	9.27%	9.10%	8.51%	10.05%
13	Authorized rate of return on common equity	10.00% {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-21870
Exhibit No.: A-1 (PDD-2)
Schedule: A-2
Page: 2 of 6
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) 2020	(c) 2021	(d) 2022	(e) 2023	(f) 2024
				Calendar Year		
	EBIT Interest Coverage Ratio					
14	Pre-tax operating income	840,785	801,024	788,467	771,660	982,033
15	Other income and deductions	41,819	83,027	102,863	128,080	109,035
16	AFUDC	7,211	8,207	5,520	3,493	24,362
17	Total EBIT	889,815	892,257	896,850	903,232	1,115,430
18	Interest charges	202,399	193,601	206,904	273,930	319,881
19	EBIT interest coverage ratio	4.40	4.61	4.33	3.30	3.49
	EBITDA Interest Coverage Ratio					
20	Total EBIT	889,815	892,257	896,850	903,232	1,115,430
21	Depreciation and amortization	739,148	771,634	757,258	797,668	865,050
22	Total EBITDA	1,628,963	1,663,891	1,654,108	1,700,901	1,980,480
23	Interest charges	202,399	193,601	206,904	273,930	319,881
24	EBITDA interest coverage ratio	8.05	8.59	7.99	6.21	6.19
	Funds Flow from Operations (FFO) Interest Coverage Ratio					
25	Net operating income	725,370	683,831	679,667	705,560	880,191
26	Depreciation and amortization	739,148	771,634	757,258	797,668	865,050
27	Deferred income taxes	321,515	(85,580)	166,168	72,405	(36,010)
28	AFUDC	7,211	8,207	5,520	3,493	24,362
29	Other major recurring non-cash items	-	-	-	-	-
30	Interest paid	207,328	198,499	202,104	266,171	300,719
	Less:					
31	Operating lease adjustment to depreciation	-	-	-	-	-
32	Subtotal	2,000,572	1,576,591	1,810,716	1,845,297	2,034,313
33	Interest charges	202,399	193,601	206,904	273,930	319,881
34	FFO interest coverage ratio	9.88	8.14	8.75	6.74	6.36

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Financial Basis
ELECTRIC RESULTS ONLY
($000)

Case No.: U-21870
Exhibit No.: A-1 (PDD-2)
Schedule: A-2

Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) 2020	(c) 2021	(d) 2022	(e) 2023	(f) 2024
				Calendar Year		
	Overall Fixed Charge Coverage Ratio					
35	Net income available to common stockholders	570,889	580,383	580,068	562,163	692,699
36	Interest charges	202,399	193,601	206,904	273,930	319,881
37	Subtotal numerator	773,289	773,984	786,972	836,092	1,012,580
38	Interest charges	202,399	193,601	206,904	273,930	319,881
39	Preferred stock dividends	1,111	1,081	1,078	1,040	1,008
40	Subtotal denominator	203,510	194,682	207,982	274,970	320,889
41	Overall fixed charge coverage ratio	3.80	3.98	3.78	3.04	3.16
	Cash Flow Coverage of Dividends Ratio					
42	Net income available to common stockholders	570,889	580,383	580,068	562,163	692,699
43	Depreciation and amortization	739,148	771,634	757,258	797,668	865,050
44	Deferred income taxes	321,515	(85,580)	166,168	72,405	(36,010)
45	Subtotal	1,631,553	1,266,437	1,503,494	1,432,236	1,521,739
46	Common dividends {6}	456,712	464,306	464,055	449,730	554,159
47	Cash flow coverage of dividends ratio	3.57	2.73	3.24	3.18	2.75
	Common Dividend Payout Ratio					
48	Common dividends {6}	456,712	464,306	464,055	449,730	554,159
49	Net income available to common stockholders	570,889	580,383	580,068	562,163	692,699
50	Common dividend payout ratio	80%	80%	80%	80%	80%
	Permanent Capitalization					
51	Long term debt	8,131,338	8,437,664	10,208,351	11,160,087	11,996,890
52	Preferred stock	37,315	37,315	37,315	37,315	37,315
53	Common equity	8,519,584	9,242,745	10,118,365	10,763,382	11,393,664
54	Total permanent capital	16,688,236	17,717,724	20,364,031	21,960,785	23,427,869
55	Long term debt	48.72%	47.62%	50.13%	50.82%	51.21%
56	Preferred stock	0.22%	0.21%	0.18%	0.17%	0.16%
57	Common equity	51.05%	52.17%	49.69%	49.01%	48.63%
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-21870
Exhibit No.: A-1 (PDD-2)
Schedule: A-2

Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) 2020	(c) 2021	(d) 2022	(e) 2023	(f) 2024
		Calendar Year				
59	Operating revenues	4,294,102	4,884,658	5,228,924	4,634,761	4,837,892
60	Operating expenses	3,482,006	4,219,304	4,515,341	3,830,317	3,977,957
61	Pre-tax operating income	812,096	665,354	713,583	804,444	859,934
62	Income taxes	166,654	34,134	57,803	30,582	41,457
63	Net operating income	645,441	631,220	655,781	773,862	818,478
64	Tax impact of pro forma interest on NOI	(5,605)	(4,444)	(4,034)	(8,406)	(9,144)
65	AFUDC	7,172	8,166	5,491	3,475	24,244
66	Interest charges	(171,758)	(166,478)	(184,127)	(235,080)	(250,433)
67	Preferred stock dividends	(1,010)	(973)	(931)	(924)	(904)
68	Net income available to common stockholders and JDITC	474,240	467,492	472,180	532,926	582,241
69	Return assignable to JDITC	(3,642)	(3,428)	(3,651)	(3,530)	(3,265)
70	Net income available to common stockholders	470,598	464,064	468,529	529,395	578,976
71	Average common equity	4,955,705	5,189,180	5,480,655	5,764,013	5,863,574
72	Earned rate of return on common equity	9.50%	8.94%	8.55%	9.18%	9.87%
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-21870
Exhibit No.: A-1 (PDD-2)
Schedule: A-2
Page: 5 of 6
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) 2020	(c) 2021	(d) 2022	(e) 2023	(f) 2024
				Calendar Year		
	EBIT Interest Coverage Ratio					
74	Pre-tax operating income	812,096	665,354	713,583	804,444	859,934
75	AFUDC	7,172	8,166	5,491	3,475	24,244
76	Total EBIT	819,267	673,520	719,075	807,919	884,179
77	Interest charges, net of pro forma interest	166,153	162,034	180,093	226,674	241,289
78	EBIT interest coverage ratio	4.93	4.16	3.99	3.56	3.66
	EBITDA Interest Coverage Ratio					
79	Total EBIT	819,267	673,520	719,075	807,919	884,179
80	Depreciation and amortization	720,318	751,470	748,017	783,248	881,096
81	Total EBITDA	1,539,586	1,424,990	1,467,092	1,591,166	1,765,275
82	Interest charges, net of pro forma interest	166,153	162,034	180,093	226,674	241,289
83	EBITDA interest coverage ratio	9.27	8.79	8.15	7.02	7.32
	Funds Flow from Operations (FFO) Interest Coverage Ratio					
84	Net operating income	645,441	631,220	655,781	773,862	818,478
85	Depreciation and amortization	720,318	751,470	748,017	783,248	881,096
86	Deferred income tax	321,515	(85,580)	166,168	72,405	(36,010)
87	AFUDC	7,172	8,166	5,491	3,475	24,244
88	Other major recurring non-cash items	-	-	-	-	-
89	Interest paid	207,328	198,499	202,104	266,171	300,719
	Less:					
90	Operating lease adjustment to depreciation	-	-	-	-	-
91	Subtotal	1,901,774	1,503,775	1,777,561	1,899,160	1,988,527
92	Interest charges, net of pro forma interest	166,153	162,034	180,093	226,674	241,289
93	FFO interest coverage ratio	11.45	9.28	9.87	8.38	8.24
	Overall Fixed Charge Coverage Ratio					
94	Net income available to common stockholders	470,598	464,064	468,529	529,395	578,976
95	Interest charges, net of pro forma interest	166,153	162,034	180,093	226,674	241,289
96	Subtotal numerator	636,751	626,098	648,623	756,069	820,265
97	Interest charges, net of pro forma interest	166,153	162,034	180,093	226,674	241,289
98	Preferred stock dividends	1,010	973	931	924	904
99	Subtotal denominator	167,162	163,007	181,025	227,598	242,193
100	Overall fixed charge coverage ratio	3.81	3.84	3.58	3.32	3.39

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
ELECTRIC RESULTS ONLY
($000)

Case No.: U-21870
Exhibit No.: A-1 (PDD-2)
Schedule: A-2
Page: 6 of 6
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) 2020	(c) 2021	(d) 2022	(e) 2023	(f) 2024
				Calendar Year		
	Cash Flow Coverage of Dividends Ratio					
101	Net income available to common stockholders	470,598	464,064	468,529	529,395	578,976
102	Depreciation and amortization	720,318	751,470	748,017	783,248	881,096
103	Deferred income tax	321,515	(85,580)	166,168	72,405	(36,010)
104	Subtotal	1,512,431	1,129,954	1,382,714	1,385,048	1,424,061
105	Common dividends {6}	376,478	371,251	374,824	423,516	463,180
106	Cash flow coverage of dividends ratio	4.02	3.04	3.69	3.27	3.07
	Common Dividend Payout Ratio					
107	Common dividends {6}	376,478	371,251	374,824	423,516	463,180
108	Net income available to common stockholders	470,598	464,064	468,529	529,395	578,976
109	Common Dividend Payout Ratio	80%	80%	80%	80%	80%
	Permanent Capitalization					
110	Long term debt, excluding securitization	7,880,109	8,214,999	9,009,833	10,397,193	11,391,866
111	Preferred stock	37,315	37,315	37,315	37,315	37,315
112	Common equity	8,555,596	9,274,520	10,133,854	10,778,709	11,405,304
113	Total permanent capital	16,473,020	17,526,834	19,181,001	21,213,217	22,834,485
114	Long term debt, excluding securitization	47.84%	46.87%	46.97%	49.01%	49.89%
115	Preferred stock	0.23%	0.21%	0.19%	0.18%	0.16%
116	Common equity	51.94%	52.92%	52.83%	50.81%	49.95%
117	Total permanent capital	100.00%	100.00%	100.00%	100.00%	100.00%

Notes

{1} Case No. U-20134 settlement agreement dated January 9, 2019; effective January 10, 2019
{2} Case No. U-20697 final order dated December 17, 2020; effective January 1, 2021
{3} Case No. U-20963 final order dated December 22, 2021; effective January 1, 2022
{4} Case No. U-21224 settlement agreement dated January 19, 2023; effective January 20, 2023
{5} Case No. U-21389 final order dated March 1, 2024; effective March 15, 2024
{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, 2024
($000)

Case No.: U-21870
Exhibit No.: A-2 (PDD-3)
Schedule: B-1
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) Source	(c) Total Amount	(d) Jurisdictional Amount
1	Total utility plant	Exhibit No.: A-2 (PDD-4)	17,559,862	17,514,439
2	Depreciation reserve	Exhibit No.: A-2 (PDD-5)	6,124,202	6,107,182
3	Net utility plant	Line 1 - Line 2	11,435,661	11,407,257
4	Customer advances for construction	Exhibit No.: A-2 (PDD-7), Column (e.1), Line 2	(66,473)	(66,430)
5	Utility plant rate base	Sum Lines 3 - 4	11,369,188	11,340,827
6	Working capital	Exhibit No.: A-2 (PDD-6)	2,918,936	2,900,501
7	Total rate base	Line 5 + Line 6	14,288,124	14,241,328

Schedule: B-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Utility Plant
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-2 (PDD-4)
Schedule: B-2
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) FERC Account Number	(c) Source	(d) Total Amount	(e) Jurisdictional Amount
1	Gross plant, including plant held for future use	101, 105	Exhibit No.: A-2 (PDD-7), Column (e.1), Line	18,512,470	18,466,325
2	Exclude: plant-in-service - renewable plant	101	WP-PDD-8	(1,656,374)	(1,652,247)
3	Deferred debits	182	WP-PDD-9	-	-
4	Construction work in progress	107	Exhibit No.: A-2 (PDD-7), Column (e.1), Line	840,451	836,383
5	Exclude: construction work in progress - renewable plant	107	WP-PDD-8	(136,684)	(136,023)
6	Total utility plant		Sum Lines 1 - 5	17,559,862	17,514,439

Schedule: B-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation Reserve and Other Deductions
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-2 (PDD-5)
Schedule: B-3
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) Source	(c) Total Amount	(d) Jurisdictional Amount
1	Accumulated depreciation, amortization and depletion of plant-in-service	Exhibit No.: A-2 (PDD-7), Column (e.1), Line 6	5,139,722	5,125,438
2	Add: cost of removal regulatory liability	WP-PDD-10	1,267,416	1,263,894
3	Exclude: depreciation reserve - renewable plan	WP-PDD-8	(282,936)	(282,150)
4	Total depreciation reserve and other deductions	Sum Lines 1 - 3	6,124,202	6,107,182

Schedule: B-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Working Capital
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-2 (PDD-6)
Schedule: B-4
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Cash, cash equivalents, and restricted cash	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 10	36,391
2	Accounts and notes receivable	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 11	280,141
3	Fuel stock	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 12	64,489
4	Materials and supplies	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 13	216,848
5	Allowances	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 14	14
6	Prepayments	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 16	933,004
7	Accrued revenue	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 17	329,191
8	Deferred taxes	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 18	272,280
9	Deferred debits	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 19	1,838,965
10	Total assets	Sum Lines 1 - 9	3,971,323
11	Accounts payable	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 23	474,206
12	Customer deposits	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 24	22,955
13	Accrued interest	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 25	66,062
14	Dividends payable	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 26	24,539
15	Accrued taxes	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 27	286,120
16	Other liabilities	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 28	72,728
17	Deferred credits	Exhibit No.: A-2 (PDD-7), Column (f.1), Line 31	105,777
18	Total liabilities	Sum Lines 11 - 17	1,052,386
19	Total working capital	Line 10 - Line 18	2,918,936
20	Jurisdictional factor		0.993684
21	Total working capital - jurisdictional	Line 19 * Line 20	2,900,501

Schedule: B-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
13-Month Average Balance Sheet
For the Historical Year Ended December 31, 2024
(In Dollars)

Source: WP-PDD-10

Case No.: U-21870
Exhibit No.: A-2 (PDD-7)
Schedule: B-5
Page: 1 of 1
Witness: PDDaly
Date: June 2025

	(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	$30,611,459,689	$ 763,754,402	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,820,893,776	$ 12,026,811,510	$ -	$ -	$ -	$ -	$ -
2	Common plant	1,170,687,957	2,278,533	-	-	-	-	-	-	691,576,300	476,833,124	-	-	-	-	-
3	Gross plant	31,782,147,646	766,032,936	-	-	-	-	-	-	18,512,470,077	12,503,644,634	-	-	-	-	-
4	Utility plant accumulated depreciation	(7,506,229,993)	(231,723,628)	-	-	-	-	-	-	(4,739,730,641)	(2,534,775,723)	-	-	-	-	-
5	Common plant accumulated depreciation	(669,119,132)	(6,085,741)	-	-	-	-	-	-	(399,991,222)	(263,042,169)	-	-	-	-	-
6	Total depreciation	(8,175,349,124)	(237,809,368)	-	-	-	-	-	-	(5,139,721,864)	(2,797,817,892)	-	-			
7	Construction work in progress	1,256,791,456	-	-	-	-	-	-	-	840,450,645	416,340,811	-	-	-	-	-
8	Net plant	24,863,589,978	528,223,567	-	-	-	-	-	-	14,213,198,858	10,122,167,553	-	-	-	-	-
9	Other property	156,176,745	119,269,189	(6,985,511)	-	-	-	-	-	-	-	-	19,423,396	-	-	24,469,671
10	Cash, cash equivalents, and restricted cash	462,645,408	409,491,256	-	-	-	-	-	-	-	-	-	-	36,391,110	16,763,043	-
11	Accounts and notes receivable	410,631,380	16,510,796	-	-	-	-	-	-	-	-	-	-	280,140,712	102,494,141	11,485,731
12	Fuel stock	64,489,415	-	-	-	-	-	-	-	-	-	-	-	64,489,415	-	-
13	Materials and supplies	273,087,084	21	-	-	-	-	-	-	-	-	-	-	216,847,732	56,239,331	-
14	Allowances	10,399,018	10,384,730	-	-	-	-	-	-	-	-	-	-	14,288	-	-
15	Gas stored underground	456,516,126	-	-	-	-	-	-	-	-	-	-	-	-	456,516,126	-
16	Prepayments	1,531,927,677	5,570,637	-	-	-	-	-	-	-	-	-	-	933,003,981	593,353,059	-
17	Accrued revenue	465,775,771	3,220,234	-	-	-	-	-	-	-	-	-	-	329,190,907	133,364,630	-
18	Deferred taxes	2,250,571,750	73,699,615	-	-	-	-	1,715,327,198	-	-	-	-	-	272,279,681	188,937,082	328,172
19	Deferred debits	3,668,686,254	1,391,571,126	-	75,948,955	-	-	-	-	-	-	94,932,735	-	1,838,964,820	266,168,929	1,099,689
20	Total assets	34,614,496,605	2,557,941,172	(6,985,511)	75,948,955	-		1,715,327,198	-	14,213,198,858	10,122,167,553	94,932,735	19,423,396	3,971,322,646	1,813,836,342	37,383,263
21	Debt, leases, and financial obligations	(11,284,471,688)	(72,779,370)	-	(11,211,692,318)	-	-	-	-	-	-	-	-	-	-	-
22	Notes payable	(723,828,019)	(711,677,889)	-	-	(12,150,130)	-	-	-	-	-	-	-	-	-	-
23	Accounts payable	(760,542,118)	(2,346,538)	-	-	-	-	-	-	-	-	-	-	(474,206,445)	(278,866,663)	(5,122,472)
24	Customer deposits	(34,320,911)	-	-	-	-	-	-	-	-	-	-	-	(22,954,721)	(11,366,190)	-
25	Accrued interest	(116,616,961)	(6,513,327)	-	-	-	-	-	-	-	-	-	-	(66,062,180)	(43,556,997)	(484,456)
26	Dividends payable	(40,898,397)	-	-	-	-	-	-	-	-	-	-	-	(24,539,038)	(16,179,406)	(179,953)
27	Accrued taxes	(481,916,513)	-	-	-	-	-	-	-	-	-	-	-	(286,119,648)	(195,516,720)	(280,145)
28	Other liabilities	(237,524,277)	(131,773,453)	-	-	-	-	-	-	-	-	(2,183,136)	-	(72,727,551)	(30,840,136)	-
29	Customer advances	(96,005,032)	-	-	-	-	-	-	-	(66,472,817)	(29,532,215)	-	-	-	-	-
30	Deferred income and investment taxes	(6,040,340,857)	5,157,581	-	-	-	(123,935,547)	(5,921,562,890)	-	-	-	-	-	-	-	-
31	Deferred credits	(3,881,109,351)	(1,017,615,120)	-	-	(50,213,869)		-	-	(1,274,275,449)	(1,346,641,250)	(59,147,537)	-	(105,776,779)	(15,928,339)	(11,511,007)
32	Total liabilities	(23,697,574,124)	(1,937,548,117)	-	(11,211,692,318)	(62,363,999)	(123,935,547)	(5,921,562,890)	-	(1,340,748,267)	(1,376,173,465)	(61,330,673)	-	(1,052,386,362)	(592,254,452)	(17,578,033)
33	Common equity	(10,879,607,682)	14,722,821	-	-	-	-	-	(10,894,330,503)	-	-	-	-	-	-	-
34	Preferred stock	(37,314,800)	-	-	-	-	-	-	(37,314,800)	-	-	-	-	-	-	-
35	Total equity	(10,916,922,482)	14,722,821	-	-	-	-	-	(10,931,645,303)	-	-	-	-	-	-	-
36	Net assets (liabilities)	$ -	$ 635,115,876	$ (6,985,511)	$ (11,135,743,363)	$ (62,363,999)	$ (123,935,547)	$ (4,206,235,692)	$ (10,931,645,303)	$ 12,872,450,591	$ 8,745,994,088	$ 33,602,062	$ 19,423,396	$ 2,918,936,283	$ 1,221,581,890	$ 19,805,230

Schedule: B-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Point-In-Time Balance Sheet
For the Historical Year Ended December 31, 2024
(In Dollars)

Case No.: U-21870
Exhibit No.: A-2 (PDD-8)
Schedule: B-6
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Source: WP-PDD-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	$ 30,938,785,294	$ 778,859,929	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,621,021,196	$ 12,538,904,168	$ -	$ -	$ -	$ -	$ -
2	Common plant	1,290,001,874	1,962,646	-	-	-	-	-	-	762,384,645	525,654,583	-	-	-	-	-
3	Gross plant	32,228,787,167	780,822,575	-	-	-	-	-	-	18,383,405,841	13,064,558,751	-	-	-	-	-
4	Utility plant accumulated depreciation	(7,372,603,550)	(283,970,663)	-	-	-	-	-	-	(4,529,457,150)	(2,559,175,737)	-	-	-	-	-
5	Common plant accumulated depreciation	(785,118,089)	(6,191,785)	-	-	-	-	-	-	(469,888,003)	(309,038,301)	-	-	-	-	-
6	Total depreciation	(8,157,721,640)	(290,162,449)	-	-	-	-	-	-	(4,999,345,153)	(2,868,214,038)	-	-			
7	Construction work in progress	1,755,480,842	-	-	-	-	-	-	-	1,312,150,819	443,330,023	-	-	-	-	-
8	Net plant	25,826,546,370	490,660,127	-	-	-	-	-	-	14,696,211,507	10,639,674,736	-	-	-	-	-
9	Other property	154,347,447	119,075,684	(6,990,731)	-	-	-	-	-	-	-	-	17,792,823	-	-	24,469,671
10	Cash, cash equivalents, and restricted cash	45,263,702	3,371,969	-	-	-	-	-	-	-	-	-	-	28,680,481	13,211,252	-
11	Accounts and notes receivable	468,848,071	37,224,762	-	-	-	-	-	-	-	-	-	-	304,108,627	106,852,789	20,661,893
12	Fuel stock	30,246,941	-	-	-	-	-	-	-	-	-	-	-	30,246,941	-	-
13	Materials and supplies	290,749,003	21	-	-	-	-	-	-	-	-	-	-	235,659,777	55,089,206	-
14	Allowances	9,020,124	9,005,836	-	-	-	-	-	-	-	-	-	-	14,288	-	-
15	Gas stored underground	435,354,565	-	-	-	-	-	-	-	-	-	-	-	-	435,354,565	-
16	Prepayments	1,607,708,357	5,570,637	-	-	-	-	-	-	-	-	-	-	980,492,340	621,645,380	-
17	Accrued revenue	598,304,295	2,879,878	-	-	-	-	-	-	-	-	-	-	343,725,032	251,699,385	-
18	Deferred taxes	2,426,198,086	93,643,000	-	-	-	-	1,651,499,678	-	-	-	-	-	401,689,810	278,885,666	479,931
19	Deferred debits	3,951,849,211	1,349,267,375	-	74,425,622	-	-	-	-	-	-	90,491,497	-	2,169,276,315	267,978,133	410,270
20	Total assets	35,844,436,174	2,110,699,288	(6,990,731)	74,425,622	-		1,651,499,678	-	14,696,211,507	10,639,674,736	90,491,497	17,792,823	4,493,893,611	2,030,716,377	46,021,766
21	Debt, leases, and financial obligations	(11,558,454,550)	(92,162,874)	-	(11,466,291,676)	-	-	-	-	-	-	-	-	-	-	-
22	Notes payable	(710,900,141)	(645,986,764)	-	-	(64,913,376)	-	-	-	-	-	-	-	-	-	-
23	Accounts payable	(918,391,213)	-	-	-	-	-	-	-	-	-	-	-	(564,679,251)	(344,054,340)	(9,657,622)
24	Customer deposits	(37,321,761)	-	-	-	-	-	-	-	-	-	-	-	(25,086,776)	(12,234,984)	-
25	Accrued interest	(120,478,559)	(9,173,866)	-	-	-	-	-	-	-	-	-	-	(66,782,816)	(44,032,136)	(489,741)
26	Dividends payable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Accrued taxes	(791,993,238)	-	-	-	-	-	-	-	-	-	-	-	(470,153,138)	(321,379,061)	(461,039)
28	Other liabilities	(224,975,930)	(164,150,623)	-	-	-	-	-	-	-	-	(2,586,846)	-	(41,750,360)	(16,488,101)	-
29	Customer advances	(95,651,167)	-	-	-	-	-	-	-	(69,567,211)	(26,083,957)	-	-	-	-	-
30	Deferred income and investment taxes	(6,054,745,644)	7,218,445	-	-	-	(121,730,410)	(5,940,233,678)	-	-	-	-	-	-	-	-
31	Deferred credits	(3,900,544,998)	(996,330,796)	-	-	(51,094,331)		-	-	(1,312,820,447)	(1,360,690,770)	(57,424,303)	-	(86,265,725)	(20,158,966)	(15,759,659)
32	Total liabilities	(24,413,457,200)	(1,900,586,479)	-	(11,466,291,676)	(116,007,707)	(121,730,410)	(5,940,233,678)	-	(1,382,387,658)	(1,386,774,726)	(60,011,149)	-	(1,254,718,067)	(758,347,589)	(26,368,061)
33	Common equity	(11,393,664,174)	11,639,891	-	-	-	-	-	(11,405,304,064)	-	-	-	-	-	-	-
34	Preferred stock	(37,314,800)	-	-	-	-	-	-	(37,314,800)	-	-	-	-	-	-	-
35	Total equity	(11,430,978,974)	11,639,891	-	-	-	-	-	(11,442,618,864)	-	-	-	-	-	-	-
36	Net assets (liabilities)	$ -	$ 221,752,699	$ (6,990,731)	$ (11,391,866,054)	$ (116,007,707)	$ (121,730,410)	$ (4,288,734,000)	$ (11,442,618,864)	$ 13,313,823,849	$ 9,252,900,010	$ 30,480,348	$ 17,792,823	$ 3,239,175,544	$ 1,272,368,788	$ 19,653,705

Schedule: C-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-9)
Schedule: C-1
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Total Amount	(d) Jurisdictional Amount
1	Sales revenues	Exhibit No.: A-3 (PDD-11)	4,586,002	4,584,699
2	Sales for resale	Exhibit No.: A-3 (PDD-11)	207,553	207,553
3	Other electric revenues	Exhibit No.: A-3 (PDD-11)	207,255	186,919
4	Total operating revenues	Sum Lines 1 - 3	5,000,811	4,979,171
5	Fuel expense	Exhibit No.: A-3 (PDD-12)	510,859	505,894
6	Purchased & interchange power	Exhibit No.: A-3 (PDD-12)	1,369,059	1,355,753
7	Operations and maintenance	Exhibit No.: A-3 (PDD-13)	916,939	914,060
8	Depreciation and amortization	Exhibit No.: A-3 (PDD-15)	884,676	881,096
9	Property taxes	Exhibit No.: A-3 (PDD-16)	244,132	243,441
10	General taxes	Exhibit No.: A-3 (PDD-16)	35,299	34,962
11	Other (local) taxes	Exhibit No.: A-3 (PDD-19)	1,668	1,652
12	State income taxes	Exhibit No.: A-3 (PDD-18)	43,503	43,794
13	Federal income taxes	Exhibit No.: A-3 (PDD-17)	41,181	41,457
14	Total operating expenses	Sum Lines 5 - 13	4,047,315	4,022,108
15	Net operating income	Line 4 - Line 14	953,495	957,062
16	AFUDC	Exhibit No.: A-3 (PDD-20)	24,362	24,244
17	Net operating income, including AFUDC	Line 15 + Line 16	977,858	981,307
	Adjustments to Net Operating Income			
18	Weather normalization	Exhibit No.: A-13 (PDD-37), Line 2	500	498
19	Purchased power administration fee revenue	Exhibit No.: A-13 (PDD-37), Line 3	(562)	(559)
20	Surcharge Revenues	Exhibit No.: A-13 (PDD-37), Line 4	(144,672)	(144,046)
21	Jobwork revenues	Exhibit No.: A-13 (PDD-37), Line 5	1,243	1,237
22	Interest income on cash operating accounts	Exhibit No.: A-13 (PDD-37), Line 6	1,212	1,207
23	Excess MDNR fees	Exhibit No.: A-13 (PDD-37), Line 7	387	385
24	Compensation expenses	Exhibit No.: A-13 (PDD-37), Line 8	532	530
25	Advertising expenses	Exhibit No.: A-13 (PDD-37), Line 9	-	-
26	Dues & donations expenses	Exhibit No.: A-13 (PDD-37), Line 10	504	501
27	Jobwork expenses	Exhibit No.: A-13 (PDD-37), Line 11	(955)	(950)
28	Interest expense on security deposits	Exhibit No.: A-13 (PDD-37), Line 12	(223)	(221)
29	One-time Legal Consultant Expense	Exhibit No.: A-13 (PDD-37), Line 13	2,849	2,835
30	Income Tax Effect of Interest	Exhibit No.: A-13 (PDD-37), Line 14	(9,524)	(9,493)
31	Interest Synchronization Adjustment	Exhibit No.: A-13 (PDD-37), Line 15	350	349
32	Total net operating income adjustments	Sum Lines 18 - 31	(148,359)	(147,729)
33	Adjusted net operating income	Line 17 + Line 32	829,498	833,578

Schedule: C-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Conversion Factor
For the Historical Year Ended December 31, 2024

Case No.: U-21870
Exhibit No.: A-3 (PDD-10)
Schedule: C-2
Page: 1 of 1
Witness: PDDaly
Date: June 2025

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, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-11)
Schedule: C-3
Page: 1 of 1
Witness: PDDaly
Date: June 2025

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	4,586,002
2	Sales for resale	P-521, p. 300(M), Col. (b), Line 14	207,553
3	Other electric revenues	P-521, p. 300(M), Col. (b), Line 30	207,255
4	Total operating revenues	Sum Lines 1 - 3	5,000,811

Schedule: C-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Fuel and Purchased Power
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-12)
Schedule: C-4
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Fuel expense - Steam Power	P-521, p. 320, Line 5	266,930
2	Fuel expense - Other Power Generation	P-521, p. 321, Line 63	256,236
3	Fuel handling	WP-PDD-12	(11,788)
4	O&M expense - Included in Other Power Generation	Exhibit No.: A-3 (PDD-14)	(518)
5	Total Fuel Expense	Sum Lines 1 - 3	510,859
6	Purchased power	P-521, p. 321, Line 76	846,040
7	Transmission expenses	P-521, p. 321, Line 112	514,541
8	Regional transmission and market operating expense	P-521, p. 322, Line 131	10,188
9	Industry Fees	WP-PDD-12	(1,710)
10	Total purchased and net interchange power	Sum Lines 6 - 9	1,369,059
11	Total cost of fuel and purchased power	Line 5 + Line 10	1,879,918

Schedule: C-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operation and Maintenance Expenses
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-13)
Schedule: C-5
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Power production expenses	P-521, p. 321, Line 80 - Exhibit No.: A-3 (PDD-12), Lines 5-6	182,957
2	Industry Fees	WP-PDD-12	1,710
3	Distribution expenses	P-521, p. 322, Line 156	366,259
4	Customer accounts expenses	P-521, p. 322, Line 164	63,012
5	Customer service & information expenses	P-521, p. 323, Line 171	261,646
6	Sales expenses	P-521, p. 323, Line 178	90
7	Administrative & general expenses	P-521, p. 323, Line 197	63,985
8	Subtotal	Sum Lines 1 - 7	939,660
9	Exclude: Electric Vehicle Amortization Expense	Exhibit No.: A-75 (PDD-51), Lines 8 + 14, column (h)	(4,291)
10	Exclude: Karn & Campbell Plant Retention & Separation Costs Amortization Expen	Exhibit No.: A-76 (PDD-52), Lines 6 + 12, column (g)	(17,699)
11	Exclude: Non-energy related uncollectibles expenses and uncollectible reserve acti	Exhibit No.: A-3 (PDD-13), Schedule: C-5.1	(2,136)
12	Include: EICP operational incentive goals	Exhibit No.: A-3 (PDD-13), Schedule: C-5.1	1,376
13	Include: cloud computing amortization included in O&M	Exhibit No.: A-3 (PDD-13), Schedule: C-5.1	28
14	Gains from disposition of allowances	P-521, p.115, Col. (g), Line 22	(0)
15	Total other operation and maintenance expenses	Sum Lines 8 - 14	916,939

Schedule: C-5.1

MICHIGAN PUBLIC SERVICE COMMISSIOI
Consumers Energy Company
Historical Operation and Maintenance Expenses by Witnes
For the Historical Year Ended December 31, 2024
(In Dollars)

Case No.: U-21870
Exhibit No.: A-3 (PDD-14)
Schedule: C-5.1
Page: 1 of 2
Witness: PDDaly
Date: June 2025

Line No.	FERC Account	Description	IT Baker	Generation Blumenstock	Forestry Stewart	Customer Experience Byrom	Incentive Compensation Conrad	Other Daly	Corporate Foster	Demand Response Gast	Employee Benefits Grob	Operations Support / Facilities Guinn	Distribution Kelly	Electric Vehicles Myrom	Total O&M	MPSC P-521	Variance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
16	95000010	(500) Operation Supervision and Engineering	$ 1,422,407	$ 6,037,072	$ -	$ -	$ -	-	$ 88,559	$ -	$ -	$ -	$ 95,359	$ -	$ 7,643,397	$ 9,907,231	$ 2,263,834
17	95011010	(501) Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	266,929,763	266,929,763
18	95012010	(501) Fuel - Nonfuel Clause	-	9,070,116	-	-	-	-	-	-	-	-	-	-	9,070,116	-	(9,070,116)
19	95020010	(502) Steam Expenses	-	11,140,307	-	-	-	-	-	-	-	-	-	-	11,140,307	15,712,257	4,571,950
20	95050010	(505) Electric Expenses	-	8,333,496	-	-	-	-	-	-	-	-	-	-	8,333,496	10,781,885	2,448,389
21	95060010	(506) Miscellaneous Steam Power Expenses	4,286,526	3,081,584	-	-	-	-	603,095	-	-	206,049	-	-	8,177,254	8,177,537	283
22	95100010	(510) Maintenance of Supervision and Engineering	-	3,104,946	-	-	-	-	88,559	-	-	-	-	-	3,193,506	4,331,158	1,137,652
23	95110010	(511) Maintenance of Structures	-	2,483,725	-	-	-	-	-	-	-	-	-	-	2,483,725	2,483,070	(655)
24	95120010	(512) Maintenance of Boiler Plant	-	12,450,579	-	-	-	-	-	-	-	-	-	-	12,450,579	17,295,459	4,844,880
25	95130010	(513) Maintenance of Electric Plant	-	2,962,313	-	-	-	-	-	-	-	-	-	-	2,962,313	2,961,985	(328)
26	95140010	(514) Maintenance of Miscellaneous Steam Plant	-	974,089	-	-	-	-	-	-	-	-	-	-	974,089	973,908	(181)
27	95350010	(535) Operation Supervision and Engineering	1,093,708	1,278,857	-	-	-	-	31,196	-	-	-	-	-	2,403,761	2,488,464	84,703
28	95360010	(536) Water for Power	-	1,674,736	-	-	-	-	-	-	-	-	-	-	1,674,736	1,674,736	-
29	95370010	(537) Hydraulic Expenses	-	4,095,470	-	-	-	-	-	-	-	-	-	-	4,095,470	4,095,470	-
30	95380010	(538) Electric Expenses	-	1,500,417	-	-	-	-	-	-	-	-	-	-	1,500,417	1,500,417	-
31	95390010	(539) Miscellaneous Hydraulic Power Generation Expenses	310,163	637,458	-	-	-	-	284,040	-	-	38,976	-	-	1,270,637	1,270,809	172
32	95400010	(540) Rents	-	2,728	-	-	-	-	-	-	-	-	-	-	2,728	2,731	3
33	95410010	(541) Maintenance Supervision and Engineering	84,660	1,376,901	-	-	-	-	31,196	-	-	-	-	-	1,492,757	1,408,106	(84,651)
34	95420010	(542) Maintenance of Structure	-	1,724,661	-	-	-	-	-	-	-	-	-	-	1,724,661	1,725,690	1,029
35	95430010	(543) Maintenance of Reservoirs, Dams, and Waterways	-	3,357,891	-	-	-	-	-	-	-	-	-	-	3,357,891	3,358,022	131
36	95440010	(544) Maintenance of Electric Plant	-	2,020,094	-	-	-	-	-	-	-	-	-	-	2,020,094	2,021,924	1,830
37	95450010	(545) Maintenance of Miscellaneous Hydraulic Plant	-	4,974,705	-	-	-	-	-	-	-	-	-	-	4,974,705	4,974,710	5
38	95460010	(546) Operation Supervision and Engineering	2,836,288	1,721,350	-	-	-	-	135,586	-	-	21,992	-	-	4,715,215	8,079,360	3,364,145
39	95470010	(547) Fuel	-	518,354	-	-	-	-	(0)	-	-	-	-	-	518,354	256,235,562	255,717,208
40	95480010	(548) Generation Expenses	-	8,560,419	-	-	-	-	-	-	-	-	-	-	8,560,419	8,647,676	87,257
41	95490010	(549) Miscellaneous Other Power Generation Expenses	-	2,023,299	-	-	-	-	-	-	-	-	-	-	2,023,299	8,380,399	6,357,100
42	95500010	(550) Rents	-	174	-	-	-	-	-	-	-	-	-	-	174	175	1
43	95510010	(551) Maintenance Supervision and Engineering	-	1,555,501	-	-	-	-	69,034	-	-	-	-	-	1,624,535	2,492,635	868,100
44	95520010	(552) Maintenance of Structures	-	276,784	-	-	-	-	-	-	-	-	-	-	276,784	1,245,012	968,228
45	95530010	(553) Maintenance of Generating and Electric Plant	-	23,096,810	-	-	-	-	-	-	-	-	-	-	23,096,810	36,337,387	13,240,577
46	95531010	(553.1) Maintenance of Computer Hardware	-	182,210	-	-	-	-	-	-	-	-	-	-	182,210	110,239	(71,971)
47	95540010	(554) Maintenance of Miscellaneous Other Power Generation Plant	-	20,233	-	-	-	-	-	-	-	-	-	-	20,233	20,233	-
48	95550010	(555) Purchased Power	-	-	-	-	-	-	-	-	-	-	-	-	-	846,028,306	846,028,306
49	95551010	(555.1) Purchased Power for Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	11,321	11,321
50	95560010	(556) System Control and Load Dispatching	1,460,836	6,133,873	-	-	-	-	-	-	-	-	597,645	-	8,192,354	8,192,354	-
51	95614010	(561.4) Scheduling, System Control and Dispatch Services	-	-	-	-	-	-	-	-	-	-	-	-	-	12,148,896	12,148,896
52	95618010	(561.8) Reliability, Planning and Standards Development Service	-	-	-	-	-	-	-	-	-	-	1,710,288	-	1,710,288	2,191,025	480,737
53	95650010	(565) Transmission of Electricity by Others	-	-	-	-	-	-	-	-	-	-	-	-	-	500,201,381	500,201,381
54	95757010	(575.7) Market Facilitation, Monitoring and Compliance Services	-	-	-	-	-	-	-	-	-	-	-	-	-	10,188,208	10,188,208
55	95800010	(580) Operation Supervision and Engineering	14,418,255	672,682	5,542,005	-	-	-	490,197	-	-	17,671	5,064,259	-	26,205,069	26,205,044	(25)
56	95820010	(582) Station Expenses	-	-	-	-	-	-	-	-	-	-	821,454	-	821,454	821,454	0
57	95830010	(583) Overhead Line Expenses	-	-	-	-	-	-	-	-	-	-	44,738,022	-	44,738,022	44,737,857	(165)
58	95840010	(584) Underground Line Expenses	-	-	-	-	-	-	-	-	-	-	9,756,876	-	9,756,876	9,757,085	209
59	95841010	(584.1) Ops Engineering Storage Equip	-	13,444	-	-	-	-	-	-	-	-	-	-	13,444	13,444	0
60	95850010	(585) Street Lighting and Signal System Expenses	-	-	-	-	-	-	-	-	-	-	1,594,014	-	1,594,014	1,594,013	(1)
61	95860010	(586) Meter Expenses	-	-	-	-	-	-	-	-	-	-	2,045,660	-	2,045,660	2,045,658	(2)
62	95870010	(587) Customer Installations Expenses	-	-	-	-	-	-	-	-	-	-	5,649,814	-	5,649,814	5,649,863	49
63	95880010	(588) Miscellaneous Expenses	-	469,295	-	-	-	-	797,951	-	-	3,081,126	19,266,340	-	23,614,711	23,614,695	(16)
64	95890010	(589) Rents	-	-	-	-	-	-	-	-	-	-	2,759,248	-	2,759,248	2,759,248	-
65	95900010	(590) Maintenance Supervision and Engineering	-	-	1,484,938	-	-	-	-	-	-	-	2,112,686	-	3,597,624	3,597,624	(0)
66	95910010	(591) Maintenance of Structures	-	-	-	-	-	-	-	-	-	-	681,561	-	681,561	681,561	0
67	95920010	(592) Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	-	15,445,647	-	15,445,647	15,445,651	4
68	95922010	(592.2) MTC Energy Stor Equip	-	189,320	-	-	-	-	-	-	-	-	-	-	189,320	250,364	61,044
69	95930010	(593) Maintenance of Overhead Lines	-	-	103,197,658	-	-	-	-	-	-	-	119,061,592	-	222,259,250	222,259,168	(82)
70	95940010	(594) Maintenance of Underground Lines	-	-	-	-	-	-	-	-	-	-	2,092,194	-	2,092,194	2,092,194	0
71	95950010	(595) Maintenance of Line Transformers	-	-	-	-	-	-	-	-	-	-	247,984	-	247,984	247,984	0
72	95960010	(596) Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-	-	-	-	86,101	-	86,101	86,101	0
73	95970010	(597) Maintenance of Meters	-	-	-	-	-	-	-	-	-	-	4,509,723	-	4,509,723	4,509,723	0
74	95980010	(598) Maintenance of Miscellaneous Distribution Plant	-	-	-	-	-	-	-	-	-	-	(109,743)	-	(109,743)	(109,743)	(0)
75	99010010	(901) Supervision	644,497	-	-	4,891,929	-	-	20,253	-	-	392,535	391,793	-	6,341,007	6,341,007	(0)
76	99020010	(902) Meter Reading Expenses	-	-	-	-	-	-	2,810	-	-	1,759	6,796,292	-	6,800,862	6,800,862	0
77	99030010	(903) Customer Records and Collection Expenses	5,479,769	-	-	23,192,145	-	-	433,178	-	-	(77)	555,399	-	29,660,414	29,660,423	9
78	99041010	(904) Uncollectible Accounts	-	-	-	-	-	-	18,073,892	-	-	-	-	-	18,073,892	20,209,904	2,136,012
79	99050010	(905) Miscellaneous Customer Accounts Expenses	-	-	-	86	-	-	-	-	-	-	-	-	86	86	(0)
80	99070010	(907) Supervision	-	-	-	387,236	-	-	-	16,693,669	-	-	-	-	17,080,905	17,189,138	108,233
81	99080010	(908) Customer Assistance Expenses	-	230,155	-	734,499	-	0	-	14,546,121	-	-	127,935	-	15,638,710	240,634,800	224,996,090
82	99090010	(909) Informational and Instructional Expenses	-	0	-	0	-	-	-	-	-	-	-	-	0	3,822,071	3,822,071
83	99160010	(916) Miscellaneous Sales Expenses	-	-	-	90,228	-	-	-	-	-	-	-	-	90,228	90,228	-
84	99200010	(920) Administrative and General Salaries	5,886,814	365,641	-	352,182	2,923,332	-	26,591,658	-	886,394	1,956,125	-	-	38,962,146	39,511,861	549,715
85	99210010	(921) Office Supplies and Expenses	4,377,966	-	-	3,874	-	-	887,863	-	2,771	3,398,484	-	-	8,670,958	8,597,789	(73,169)
86	99220010	(922) Administrative Expenses Transferred-Credi	-	-	-	-	(1,549,366)	-	(19,587,932)	-	-	-	-	-	(21,137,298)	(21,137,298)	(0)
87	99230010	(923) Outside Services Employed	17,383,034	-	-	135,398	-	-	8,836,450	-	699,996	1,601,143	523,085	-	29,179,105	33,142,571	3,963,466
88	99240010	(924) Property Insurance	-	-	-	-	-	-	2,198,504	-	-	-	-	-	2,198,504	2,198,504	(0)
89	99250010	(925) Injuries and Damages	-	-	-	-	-	-	19,017,685	-	-	-	-	-	19,017,685	19,017,685	(0)
90	99260010	(926) Employee Pensions and Benefits	-	-	-	-	-	-	(601,950)	-	(27,558,215)	-	-	-	(28,160,165)	(28,139,871)	20,294
91	99280010	(928) Regulatory Commission Expenses	-	-	-	-	-	-	2,027,677	-	-	-	-	-	2,027,677	2,027,677	(0)
92	99302010	(930.2) Miscellaneous General Expenses	-	119,896	-	1,339,251	-	-	2,962,558	-	-	-	-	-		5,072,507	
93	99310010	(931) Rents	-	-	-	-	-	-	(46,406)	-	-	58,836	-	-		164,383	
94	99350010	(935) Maintenance of General Plant	-	-	-	-	-	-	(142,106)	-	-	3,789,039	-	-	3,646,932	3,529,432	(117,500)
95		Sub-Total O&M by Witness	$ 59,684,923	$ 128,431,583	$ 110,224,601	$ 31,126,827	$ 1,373,966	$ 0	$ 63,293,549	$ 31,239,790	$ (25,969,054)	$ 14,563,657	$ 246,621,227	$ -	$ 660,591,070	$ 2,819,578,248	$ 2,158,987,178

Schedule C-5.1

MICHIGAN PUBLIC SERVICE COMMISSIOI
Consumers Energy Company
Historical Operation and Maintenance Expenses by Witnes
For the Historical Year Ended December 31, 2024

Case No.: U-21870
Exhibit No.: A-3 (PDD-14)
Schedule: C-5.1
Page: 2 of 2
Witness: PDDaly
Date: June 2025

Line No.	FERC Account	Description	Baker	Blumenstock	Stewart	Byrom	Conrad	Daly	Foster	Gast	Grob	Guinn	Kelly	Myrom	Total O&M	MPSC P-521 Pg 320-323	Variance
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Items Included in CECo Other O&M Expense Not Included in the MPSC P-521															
96	94040010	Limited Term Utility -Electric	28,173	-	-	-	-	-	-	-	-	-	-	-	28,173	-	(28,173)
97	94160000	Expense Jobbing & CTR	-	-	-	-	-	1,277,564	-	-	-	-	-	-	1,277,564	-	(1,277,564)
98	94265010	Other Deductions	-	-	-	-	1,375,975	-	-	-	-	-	-	-	1,375,975	-	(1,375,975)
99	94310000	Other Interest Expense					-	297,786							297,786	-	(297,786)
100		Allocation Difference	226,555	6,822	-	9	58	-	3	-	(946)	-	(832)	-	231,669	-	(231,669)
101		Total O&M by Witness (Sum Lines 95-100)	$ 59,939,651	$ 128,438,405	$ 110,224,601	$ 31,126,836	$ 2,750,000	$ 1,575,351	$ 63,293,552	$ 31,239,790	$ (25,970,000)	$ 14,563,657	$ 246,620,395	$ -	$ 663,802,237	$ 2,819,578,248	$ 2,155,776,010
		Reconciliation of MPSC P-521 to Exhibit No.: A-3 (PDD-13) and Exhibit No.: A-13 (PDD-37)															
102		Total MPSC P-521 O&M Expense, p. 323, Line 198	Col. (o), Line 101													2,819,578,248	
103		Exclude: Fuel and Purchase Power Expense:														(1,879,917,799)	
104		Exclude: Gain Sale NOX Allow (included in PSCR														(54)	
105		Exclude: Electric Vehicle Amortization Expens														(4,290,502)	
106		Exclude: Karn & Campbell Plant Retention & Separation Costs Amortization Expens														(17,698,534)	
107		Exclude: Non-energy related uncollectible expenses and uncollectible reserve activi														(2,136,012)	
108		Include: EICP operational incentive goals														1,375,975	
109		Include: cloud computing amortization included in O&M														28,173	
110		Include: Rounding Adjustments															
111		Total adjusted MPSC P-521 O&M expens	Sum of Lines 102 through 110													916,939,494	
112		Total O&M expense per Exhibit No.: A-13 (PDD-37														916,939,495	
113		Difference														(0)	
114		Total O&M expense per Exhibit No.: A-13 (PDD-37														916,939,495	
115		Exclude: EWR Expenses														(200,339,000)	
116		Exclude: REP Expenses														(29,014,919)	
117		Exclude: LIEAF Expenses														(19,792,000)	
118		Exclude: DR Over/Under-recovery Expens														(96,572)	
119		Exclude: one-time consulting expense:														(3,812,000)	
120		Exclude: Corporate Giving Salaries Disallowanc														(712,010)	
121		Exclude: Excess MDNR Fees														(517,245)	
122		Exclude: Dues/Donations														(673,852)	
123		Include: Jobwork Expenses														1,277,564	
124		Include: Interest expense on security deposits														297,786	
125		Include: Rounding Adjustments														268,986	
126		Total adjusted other O&M expens	Sum of Lines 114 through 125													663,826,233	
127		Total O&M expense per Exhibit No.: A-13 (PDD-42														663,802,237	
128		Difference														23,996	

Schedule: C-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation and Amortization Expenses
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-15)
Schedule: C-6
Page: 1 of 1
Witness: PDDaly
Date: June 2025

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	190,463
2	Transmission plant - depreciation expense	P-521, p. 336M, Col. (b), Line 7	-
3	Distribution plant - depreciation expense	P-521, p. 336M, Col. (b), Line 8	344,340
4	General plant - depreciation expense	P-521, p. 336M, Col. (b), Line 9	10,138
5	Common plant - electric - depreciation expense	P-521, p. 336M, Col. (b), Line 10	17,685
6	Total amortization of limited-term electric plant (Acct 404)	P-521, p. 336M, Col. (c), Line 11	878
7	Total amortization of other electric plant (Acct 405)	P-521, p. 336M, Col. (d), Line 11	60,859
8	Amortization of utility plant acquisition adjustment	P-521, p.115, Col. (g), Line 9 + P-521, p.117, Col. (c), Line 44	20,377
9	Regulatory debits	P-521, p.115, Col. (g), Line 12	217,975
10	Subtotal	Sum Lines 1 - 9	862,715
11	Less: transmission expense	Line 2 *-1	-
12	Include: Electric Vehicle Amortization Expense	Exhibit No.: A-75 (PDD-51), Lines 8 + 14, column (h)	4,291
13	Include: Karn & Campbell Plant Retention & Separation Costs Amortization Expens	Exhibit No.: A-76 (PDD-52), Lines 6 + 12, column (g)	17,699
14	Exclude: Cloud computing amortization included in O&M	Exhibit No.: A-3 (PDD-14)	(28)
14	Total depreciation and amortization expenses	Sum Line 10 + Line 14	884,676

Schedule C-7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
General Taxes
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-16)
Schedule: C-7
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Real and personal property taxes	P-521, p. 262.1, Col. (i), Line 44	244,132
2	Federal unemployment tax	P-521, p. 262.1, Col. (i), Line 4	103
3	Federal FICA tax	P-521, p. 262.1, Col. (i), Line 6	23,447
4	State income tax	P-521, p. 262.1, Col. (i), Line 16 through 35	497
5	Total payroll taxes	Sum Lines 2 - 4	24,047
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	11,104
8	State franchise tax	P-521, p. 262.1, Col. (i), Line 40	0
9	State sales and use tax absorbed by company	P-521, p. 262.1, Col. (i), Line 41	148
10	Other general taxes	Sum Lines 6 - 9	11,252
11	Total general taxes	Line 1 + Line 5 + Line 10	279,431

Schedule: C-8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Federal Income Taxes
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-17)
Schedule: C-8
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Federal income taxes	P-521, p.115, Col. (g), Line 15	97,831
2	Provision for deferred income taxes	P-521, p.115, Col. (g), Line 17	348,801
3	Provision for deferred income taxes - credit	P-521, p.115, Col. (g), Line 18	(381,368)
4	Investment tax credit adjustment, net	P-521, p.115, Col. (g), Line 19	(3,443)
4	Deferred state income tax	Tax Department	(19,658)
5	Deferred other (local) income tax	Tax Department	(981)
6	Total federal income taxes	Sum Lines 1 - 5	41,181

Schedule: C-9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
State Income Taxes
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-18)
Schedule: C-9
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	State income taxes	P-521, p. 262.1, Col. (i), Lines 11 through 15	23,845
2	Deferred state income taxes	Tax Department	19,658
3	Total state income taxes	Line 1 + Line 2	43,503

Schedule: C-10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Other (or Local) Taxes
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-19)
Schedule: C-10
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Other (local) income taxes	P-521, p. 262.1, Col. (i), Line 45	687
2	Deferred other (local) income taxes	Tax Department	981
3	Total other (local) income taxes	Line 1 + Line 2	1,668

Schedule: C-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Allowance for Funds Used During Construction
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-20)
Schedule: C-11
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Total allowance for funds used during construction	WP-PDD-11	24,362

Schedule: C-12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Income Tax Effect of Interest
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-21)
Schedule: C-12
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-2 (PDD-3)	14,288,124
2	Weighted cost of debt {a}	Exhibit No.: A-4 (PDD-23)	0.0175
3	Allowable interest expense	Line 1 * Line 2	249,872
4	Actual interest expense {b}	Line {b.8}	287,567
5	Increase/ (decrease) in allowable interest deduction	Line 3 - Line 4	(37,695)
6	Impact on taxable income	Line 5 * -1	37,695
7	Impact on local income taxes	Line 6 * 0.16% Other (Local) Income Tax Rate	60
8	Impact on state income taxes	Line 6 * 5.24% State Income Tax Rate	1,975
9	Impact on federal taxable income	Line 6 - Line 7 - Line 8	35,660
10	Impact on federal income tax	Line 9 * 21.00% Federal Income Tax Rate	7,489
11	Total impact on net operating income	(Line 7 + Line 8 + Line 10) * -1	(9,524)

Notes

{a} Excludes JDITC

{b} Calculation of actual interest expense

{b.1}	Total fixed charges - financial basis	WP-PDD-11	325,383
{b.2}	Lease interest expense	SAP Accounts 95470010, 95550010, 99302010	12,318
{b.3}	Surcharge interest expense	WP-PDD-14	32,314
{b.4}	Subtotal	Line {b.1} - Line {b.2} - Line {b.3}	280,751
{b.5}	AFUDC debt	WP-PDD-11	7,824
{b.6}	Subtotal	Line {b.4} + Line {b.5}	288,575
{b.7}	Preferred stock dividends	WP-PDD-11	1,008
{b.8}	Acutal ratemaking interest expense	Line {b.6} - Line {b.7}	287,567

Schedule: C-13

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Interest Synchronization Adjustment
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-3 (PDD-22)
Schedule: C-13
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-2 (PDD-3)	14,288,124
2	JDITC debt-related portion of the capital structure	Exhibit No.: A-4 (PDD-23)	0.0024
3	Portion of rate base funded by JDITC	Line 1 * Line 2	33,772
4	Cost of JDITC - debt portion	Exhibit No.: A-4 (PDD-23)	0.0410
5	Allowable JDITC interest expense	Line 3 * Line 4	1,385
6	Impact on taxable income	Line 5 * -1	(1,385)
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	(73)
9	Impact on federal taxable income	Line 6 - Line 7 - Line 8	(1,311)
10	Impact on federal income tax	Line 9 * 21.00% Federal Income Tax Rate	(275)
11	Total impact on net operating income	(Line 7 + Line 8 + Line 10) * -1	350

Schedule: D-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure and Rate of Return Summary
For the Historical Year Ended December 31, 2024
($000)

Case No.: U-21870
Exhibit No.: A-4 (PDD-23)
Schedule: D-1
Page: 1 of 1
Witness: PDDaly
Date: June 2025

	(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 (PDD-7), Col. (d.1), Line 36	11,135,743	50.46%	42.09%	4.10% {1}	2.07%	1.73%		1.73%
2	Preferred stock	Exhibit No.: A-2 (PDD-7), Col. (d.5), Line 34	37,315	0.17%	0.14%	4.50% {2}	0.01%	0.01%	1.3381	0.01%
3	Common equity	Exhibit No.: A-2 (PDD-7), Col. (d.5), Line 33	10,894,331	49.37%	41.17%	9.90% {3}	4.89%	4.08%	1.3381	5.45%
4	Permanent capital	Sum of Lines 1 through 3	22,067,389							
5	Utility term loan	Exhibit No.: A-2 (PDD-7), Col. (d.2), Line 21	-		0.00%	9.49% {4}		0.00%		0.00%
6	Notes payable	Exhibit No.: A-2 (PDD-7), Col. (d.2), Line 22	12,150		0.05%	9.49% {4}		0.00%		0.00%
7	Advance renewable reg liability	Exhibit No.: A-2 (PDD-7), Col. (d.2), Line 31	50,214		0.19%	9.49% {4}		0.02%		0.02%
8	Short term debt	Sum of Lines 5 through 7	62,364							
9	Deferred federal income tax	Exhibit No.: A-2 (PDD-7), Col. (d.4), Line 36	4,206,236		15.90%	0.00%		0.00%		0.00%
10	Deferred JDITC - long term debt	See Note {5}	62,541		0.24%	4.10%		0.01%		0.01%
11	Deferred JDITC - preferred stock	See Note {5}	210		0.00%	4.50%		0.00%	1.3381	0.00%
12	Deferred JDITC - common equity	See Note {5}	61,185		0.23%	9.90%		0.02%	1.3381	0.03%
13	Total deferred JDITC	Sum of Lines 10 through 12	123,936							
14	Total	Sum of Lines 4, 8, 9, and 13	26,459,924					5.86%		7.25%

Notes

{1} Exhibit No.: A-4 (PDD-24)
{2} Exhibit No.: A-4 (PDD-26)
{3} Exhibit No.: A-4 (PDD-27)
{4} Exhibit No.: A-4 (PDD-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, 2024
($000)

Case No.: U-21870
Exhibit No.: A-4 (PDD-24)
Schedule: D-2
Page: 1 of 1
Witness: PDDaly
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No	Description	Original Issue Date	Stated Maturity Date	Interest Rate %	Amount of Offering	Price to Public %	Underwriting & Financing Expense %	Net Proceeds to the Company %	Cost Based on Net Proceeds %	13-Mo Avg Amount Outstanding	Annual Cost
Mortgage Bonds											
1	3.13%	8/18/2014	8/31/2024	3.125%	250,000	99.90%	0.790%	99.11%	3.230%	173,077	5,356
2	3.19%	12/17/2012	12/16/2024	3.190%	51,500	100.00%	0.536%	99.46%	3.244%	47,538	1,593
3	5.24%	5/30/2023	5/15/2026	5.240%	115,000	100.00%	0.116%	99.88%	5.282%	115,000	6,072
4	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
5	3.39%	12/17/2012	12/15/2027	3.390%	35,500	100.00%	0.540%	99.46%	3.436%	35,500	1,216
6	0.038	11/13/2018	11/15/2028	3.800%	300,000	99.75%	0.752%	99.00%	3.922%	300,000	11,698
7	4.65%	1/10/2023	3/1/2028	4.650%	425,000	99.81%	0.833%	98.98%	4.875%	425,000	20,606
8	5.07%	5/30/2023	5/15/2029	5.070%	50,000	100.00%	0.232%	99.77%	5.115%	50,000	2,556
9	4.90%	8/4/2023	2/15/2029	4.900%	500,000	99.95%	0.806%	99.14%	5.079%	500,000	25,272
10	4.60%	1/9/2024	5/30/2029	4.600%	600,000	99.77%	0.704%	99.06%	4.798%	553,846	28,149
11	4.70%	8/5/2024	1/15/2030	4.700%	700,000	99.78%	0.712%	99.06%	4.898%	269,231	13,857
12	3.60%	8/11/2022	8/15/2032	3.600%	350,000	99.93%	0.850%	99.08%	3.711%	350,000	12,898
13	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
14	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
15	5.17%	5/30/2023	5/15/2032	5.170%	95,000	100.00%	0.340%	99.66%	5.218%	95,000	4,947
16	4.63%	2/23/2023	5/15/2033	4.625%	700,000	99.45%	0.847%	98.60%	4.799%	700,000	33,331
17	5.80%	8/11/2005	9/15/2035	5.800%	175,000	99.81%	1.046%	98.76%	5.888%	175,000	10,222
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	16,908
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	12,936
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	20,632
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	10,535
32	3.10%	9/3/2019	8/15/2050	3.100%	550,000	99.29%	0.971%	98.32%	3.186%	550,000	13,989
33	3.50%	3/26/2020	8/1/2051	3.500%	575,000	100.00%	1.094%	98.91%	3.558%	575,000	18,366
34	2.65%	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	19,067
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	2.50%	5/13/2020	5/1/2060	2.500%	525,000	100.00%	1.047%	98.95%	2.542%	525,000	13,374
40	4.35%	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	4,002
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	7,066
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	6,602
44	Total First Mortgage Bonds									11,138,687	450,682
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	1,672
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	2,014
Cost of Long-Term Debt Calculation											
48	Total Annual Cost										452,696
49	Amortization of Losses on Reacquired Debt with Refunding (including Call Premiums)										4,119
50	Total Long-Term Debt Annual Cost Balance										456,815
51	Total Long-Term Debt										11,248,687
52	Unamortized Debt Discount, Premium, and Expense										(31,371)
53	Unamortized Debt Costs										(81,573)
54	Total Long-Term Debt Balance										11,135,743
55	Average Cost of Long-Term Debt										4.10%

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, 2024
($000)

Case No.: U-21870
Exhibit No.: A-4 (PDD-25)
Schedule: D-3
Page: 1 of 1
Witness: PDDaly
Date: June 2025

(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 (PDD-7), Col. (d.2), Line 2	-		
2	Notes payable	Exhibit No.: A-2 (PDD-7), Col. (d.2), Line 2	12,150		
3	Advanced renewable reg liability	Exhibit No.: A-2 (PDD-7), Col. (d.2), Line 3	50,214		
4	Total	Sum of Lines 1 through 3	62,364	5,918	9.49%

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, 2024
($000)

Case No.: U-21870
Exhibit No.: A-4 (PDD-26)
Schedule: D-4
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) Annual Dividend	(c) Par Value	(d) Discount / (Premium)	(e) Finance Expense	(f) Net Proceeds Received	(g) Number of Shares Outstanding	(h) Total Value of Outstanding Proceeds {1}	(i) Cost Rate %	(j) Annual Dollar Amount
1	Preferred stock	4.50	100	-	-	100	373,148	37,315	4.50%	1,679

Notes

{1} Exhibit No.: A-2 (PDD-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, 2024

Case No.: U-21870
Exhibit No.: A-4 (PDD-27)
Schedule: D-5
Page: 1 of 1
Witness: PDDaly
Date: June 2025

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 1, 2024 in Electric Rate Case U-21389.

Schedule E-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Service Area Calendar Sales by Major Customer Classes and System Output
5-Year Historical
(GWh)

Case No.: U-21870
Exhibit No.: A-5 (EMB-1)
Schedule: E-1
Page: 1 of 2
Witness: EMBreuring
Date: June 2025

Line No.			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Total Company Electric Deliveries							**Losses & Company Use**		
	Year		**Residential**	**Commercial**	**Industrial**	**Other**	**Total**	**GWh**	**% of Output**	**System Output**
1	2020	Hist	13,331	11,918	9,642	512	35,403	2,792	7.3%	38,195
2	2021	Hist	13,229	12,436	10,086	493	36,244	2,777	7.1%	39,021
3	2022	Hist	12,977	12,602	11,292	463	37,333	2,775	6.9%	40,108
4	2023	Hist	12,208	12,462	11,200	423	36,293	2,707	6.9%	39,000
5	2024	Hist	12,495	12,718	11,173	393	36,780	2,951	7.4%	39,731
	Bundled Electric Deliveries							**Losses & Company Use**		
	Year		**Residential**	**Commercial**	**Industrial**	**Other**	**Total**	**GWh**	**% of Output**	**System Output**
6	2020	Hist	13,331	11,014	6,952	512	31,810	2,742	7.9%	34,552
7	2021	Hist	13,229	11,504	7,375	493	32,600	2,660	7.5%	35,260
8	2022	Hist	12,977	11,676	8,455	463	33,570	2,756	7.6%	36,326
9	2023	Hist	12,208	11,553	8,547	423	32,731	2,633	7.4%	35,365
10	2024	Hist	12,495	11,766	8,543	393	33,197	2,858	7.9%	36,055
	Choice Electric Deliveries							**Losses & Company Use**		
	Year		**Residential**	**Commercial**	**Industrial**	**Other**	**Total**	**GWh**	**% of Output**	**System Output**
11	2020	Hist	-	904	2,689	-	3,593	49	1.4%	3,643
12	2021	Hist	-	932	2,712	-	3,644	116	3.1%	3,760
13	2022	Hist	-	926	2,837	-	3,763	20	0.5%	3,783
14	2023	Hist	-	909	2,653	-	3,562	74	2.0%	3,636
15	2024	Hist	-	953	2,630		3,583	93	2.5%	3,675

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-21870
Exhibit No.: A-5 (EMB-1)
Schedule: E-1
Page: 2 of 2
Witness: EMBreuring
Date: June 2025

Total Company Electric Deliveries

Line No.	Year		(a) Residential	(b) Commercial	(c) Industrial	(d) Other	(e) Total
16	2020	Hist	13,105	11,870	9,641	512	35,127
17	2021	Hist	12,747	12,258	10,059	492	35,557
18	2022	Hist	12,619	12,450	11,283	462	36,815
19	2023	Hist	12,597	12,560	11,211	423	36,791
20	2024	Hist	12,571	12,653	11,159	393	36,776

Bundled Electric Deliveries

	Year		Residential	Commercial	Industrial	Other	Total
21	2020	Hist	13,105	10,973	6,950	512	31,539
22	2021	Hist	12,747	11,338	7,350	492	31,927
23	2022	Hist	12,619	11,528	8,448	462	33,058
24	2023	Hist	12,597	11,657	8,553	423	33,231
25	2024	Hist	12,571	11,711	8,531	393	33,207

Choice Electric Deliveries

	Year		Residential	Commercial	Industrial	Other	Total
26	2020	Hist	-	897	2,691	-	3,587
27	2021	Hist	-	921	2,709	-	3,630
28	2022	Hist	-	922	2,835	-	3,757
29	2023	Hist	-	902	2,657	-	3,560
30	2024	Hist	-	942	2,627	-	3,569

Schedule: A-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Deficiency (Sufficiency)
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-11 (PDD-28)
Schedule: A-1
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Total Amount
1	Rate base	Exhibit No.: A-12 (PDD-31)	15,367,518
2	Adjusted net operating income	Exhibit No.: A-13 (PDD-36)	707,746
3	Overall rate of return	Line 2 / Line 1	4.61%
4	Required rate of return	Exhibit No.: A-14 (MRB-1), Schedule D-1	6.35%
5	Income requirement	Line 1 * Line 4	975,589
6	Income deficiency (sufficiency)	Line 5 - Line 2	267,843
7	Revenue conversion factor	Exhibit No.: A-13 (PDD-38)	1.3381
8	Revenue Deficiency / (Sufficiency)	Line 6 * Line 7	358,395
9	Return On - Campbell Regulatory Asset	Exhibit No.: A-81 (PDD-57)	77,486
10	Revenue Deficiency / (Sufficiency) - Total	Line 8 + Line 9	435,881

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
For the Projected 12-Month Period Ending April 30, 2027
ELECTRIC RESULTS ONLY
($000)

Case No.: U-21870
Exhibit No.: A-11 (PDD-29)
Schedule: A-2

Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) No Rate Relief	(c) Full Rate Relief
1	Operating revenues	5,020,623	5,456,504
2	Operating expenses	4,248,420	4,248,420
3	Pre-tax operating income	772,203	1,208,083
4	Income taxes	80,483	248,521
5	Net operating income	691,720	959,563
6	Tax effect of pro forma interest on NOI	Included in Line 4	Included in Line 4
7	AFUDC	16,026	16,026
8	Interest charges, net of tax benefit	(294,813)	(294,813)
9	Preferred stock dividends	(796)	(796)
10	Net income available to common stockholders and JDITC	412,137	679,979
11	Return assignable to JDITC	(3,580)	(3,580)
12	Net income available to common stockholders	408,556	676,399
13	Average common equity	6,599,015	6,599,015
14	Earned rate of return on common equity	6.19%	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, 2027
ELECTRIC RESULTS ONLY
($000)

Case No.: U-21870
Exhibit No.: A-11 (PDD-29)
Schedule: A-2

Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) No Rate Relief	(c) Full Rate Relief
	EBIT Interest Coverage Ratio		
16	Pre-tax operating income	772,203	1,208,083
17	AFUDC	16,026	16,026
18	Total EBIT	788,229	1,224,110
19	Interest charges, net of tax benefit	294,813	294,813
20	EBIT interest coverage ratio	2.67	4.15
	EBITDA Interest Coverage Ratio		
21	Total EBIT	788,229	1,224,110
22	Depreciation and amortization	813,088	813,088
23	EBITDA	1,601,317	2,037,197
24	Interest charges, net of tax benefit	294,813	294,813
25	EBITDA interest coverage ratio	5.43	6.91
	FFO Interest Coverage Ratio {2}		
26	Net operating income	691,720	959,563
27	Depreciation and amortization	813,088	813,088
28	Deferred income taxes	(36,010)	(36,010)
29	AFUDC	16,026	16,026
30	Other major recurring non-cash items	-	-
31	Interest paid	300,719	300,719
	Less:		
32	Operating lease adjustment to depreciation	-	-
33	Subtotal	1,785,542	2,053,385
34	Interest charges, net of tax benefit	294,813	294,813
35	FFO interest coverage ratio	6.06	6.97
	Overall Fixed Charge Coverage Ratio		
36	Net income available to common stockholders	408,556	676,399
37	Interest charges, net of tax benefit	294,813	294,813
38	Subtotal numerator	703,369	971,212
39	Interest charges, net of tax benefit	294,813	294,813
40	Preferred stock dividends	796	796
41	Subtotal denominator	295,609	295,609
42	Overall fixed charge coverage ratio	2.38	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, 2027
ELECTRIC RESULTS ONLY
($000)

Case No.: U-21870
Exhibit No.: A-11 (PDD-29)
Schedule: A-2
Page: 3 of 3
Witness: PDDaly
Date: June 2025

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	408,556	676,399
44	Depreciation and amortization	813,088	813,088
45	Deferred taxes	(36,010)	(36,010)
46	Subtotal	1,185,633	1,453,476
47	Common dividends {3}	326,845	541,119
48	Cash flow coverage of dividends ratio	3.63	2.69
	Common Dividend Payout Ratio		
49	Common dividends {3}	326,845	541,119
50	Net income available to common stockholders	408,556	676,399
51	Common dividend payout ratio	80%	80%
	Permanent Capitalization		
52	Long term debt, excluding securitization	13,465	13,465
53	Preferred stock	37	37
54	Common equity	13,916	13,916
55	Permanent capitalization	27,418	27,418
56	Long term debt, excluding securitization	49.11%	49.11%
57	Preferred stock	0.14%	0.14%
58	Common equity	50.75%	50.75%
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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-11 (PDD-30)
Schedule: A-3
Page: 1 of 1
Witness: PDDaly
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)
Line		Source		Amounts		
No.	Description	Historical Year	Projected Test Year	Historical Year	Change	Test Year
1	Net utility plant	Exhibit No.: A-2 (PDD-3)	Exhibit No.: A-12 (PDD-31)	11,340,827	1,900,804	13,241,630
2	Working capital	Exhibit No.: A-2 (PDD-3)	Exhibit No.: A-12 (PDD-31)	2,900,501	(774,614)	2,125,887
3	Rate base	Line 1 + Line 2	Line 1 + Line 2	14,241,328	1,126,190	15,367,518
4	Rate of return	Exhibit No.: A-4 (PDD-23)	Exhibit No.: A-14 (MRB-1), Schedule D-	5.86%		6.35%
5	Income requirement	Line 3 * Line 4	Line 3 * Line 4	835,097	140,492	975,589
6	Adjusted net operating income	Exhibit No.: A-3 (PDD-9)	Exhibit No.: A-13 (PDD-36)	833,578	(125,832)	707,746
7	Income deficiency (sufficiency)	Line 5 - Line 6	Line 5 - Line 6	1,519	266,324	267,843
8	Revenue conversion factor	Exhibit No.: A-3 (PDD-10)	Exhibit No.: A-13 (PDD-38)	1.3381		1.3381
9	Revenue deficiency (sufficiency)	Line 7 * Line 8	Line 7 * Line 8	2,033	356,362	358,395

Schedule: B-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Rate Base
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-12 (PDD-31)
Schedule: B-1
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Total utility plant	Exhibit No.: A-12 (PDD-32)	19,958,747
2	Depreciation reserve	Exhibit No.: A-12 (PDD-33)	6,650,643
3	Net utility plant	Line 1 - Line 2	13,308,103
4	Customer advances for construction	Exhibit No.: A-2 (PDD-7)	(66,473)
5	Utility plant rate base	Sum Lines 3 - 4	13,241,630
6	Working capital	Exhibit No.: A-12 (PDD-34)	2,125,887
7	Total rate base	Line 5 + Line 6	15,367,518

Schedule: B-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Utility Plant
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-12 (PDD-32)
Schedule: B-2
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) FERC Account Number	(c) Source	(d) Amount
1	Distribution		WP-PDD-21, Col. (c), Line 1	14,110,243
2	Production (Hydro)		WP-PDD-21, Col. (c), Line 2	257,460
3	Production (Hydro Ludington)		WP-PDD-21, Col. (c), Line 3	630,876
4	Production (Steam)		WP-PDD-21, Col. (c), Line 4	440,912
5	Production (Solar)		WP-PDD-21, Col. (c), Line 5	-
6	Production (Other)		WP-PDD-21, Col. (c), Line 6	1,906,468
7	Intangibles		WP-PDD-21, Col. (c), Line 7	566,466
8	E-GP Structures		WP-PDD-21, Col. (c), Line 8	194,933
9	E-GP Computers		WP-PDD-21, Col. (c), Line 9	12,887
10	E-GP Transportation		WP-PDD-21, Col. (c), Line 10	162,953
11	E-GP Other		WP-PDD-21, Col. (c), Line 11	75,885
12	C-GP Structures		WP-PDD-21, Col. (c), Line 12	177,141
13	C-GP Computers		WP-PDD-21, Col. (c), Line 13	51,698
14	C-GP Transportation		WP-PDD-21, Col. (c), Line 14	80,500
15	C-GP Other		WP-PDD-21, Col. (c), Line 15	118,040
16	Production Acq Adjustment		WP-PDD-21, Col. (c), Line 16	584,035
17	Total plant-in-service	101	Sum of Lines 1 through 16	19,370,498
18	Plant purchased or sold	102	WP-PDD-10	-
19	Experimental plant unclassified	103	WP-PDD-10	-
20	Plant leased to others	104	WP-PDD-10	-
21	Plant held of future use	105	WP-PDD-10	9,439
22	Completed construction not classified	106	WP-PDD-10	-
23	Construction work in progress	107	WP-PDD-22 Col. (c), Line 19	578,809
24	Total utility plant		Sum Lines 17 through 23	19,958,747

Schedule: B-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation Reserve and Other Deductions
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-12 (PDD-33)
Schedule: B-3
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Distribution	WP-PDD-23, Col. (c), Line 1	4,004,051
2	Production (Hydro)	WP-PDD-23, Col. (c), Line 2	402,876
3	Production (Hydro Ludington)	WP-PDD-23, Col. (c), Line 3	257,607
4	Production (Steam)	WP-PDD-23, Col. (c), Line 4	300,341
5	Production (Solar)	WP-PDD-23, Col. (c), Line 5	-
6	Production (Other)	WP-PDD-23, Col. (c), Line 6	703,704
7	Intangibles	WP-PDD-23, Col. (c), Line 7	453,236
8	E-GP Structures	WP-PDD-23, Col. (c), Line 8	47,808
9	E-GP Computers	WP-PDD-23, Col. (c), Line 9	7,805
10	E-GP Transportation	WP-PDD-23, Col. (c), Line 10	76,229
11	E-GP Other	WP-PDD-23, Col. (c), Line 11	31,415
12	C-GP Structures	WP-PDD-23, Col. (c), Line 12	81,869
13	C-GP Computers	WP-PDD-23, Col. (c), Line 13	25,890
14	C-GP Transportation	WP-PDD-23, Col. (c), Line 14	64,803
15	C-GP Other	WP-PDD-23, Col. (c), Line 15	41,797
16	Production Acq Adjustment	WP-PDD-23, Col. (c), Line 16	151,211
17	Total depreciation reserve and other deductions	Sum Lines 1 - 16	6,650,643

Schedule: B-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Working Capital
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-12 (PDD-34)
Schedule: B-4
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) Historical Year Working Capital	(c) Change	(d) December 2024 Working Capital	(e) Pension Adjustment	(f) OPEB Adjustment	(g) Pension/OPEB Volatility Mechanism	(h) Accrued Tax Adjustment	(i) Prepaid Cloud Computing Adjustment	(j) PowerMIDrive and PowerMIFleet Adjustment	(k) Karn & Campbell Retention	(l) Campbell NBV, Ash Disposal, Decommissioning	(m) S/4 HANA Implementation Deferral Adjustment	(n) Other	(o) Total Adjustments	(p) Test Year Working Capital
1	Cash, cash equivalents, and restricted cash	36,391	-	36,391	-	-	-	-	-	-	-	-	-	13,994	13,994	50,385
2	Accounts and notes receivable	280,141	-	280,141	-	-	-	-	-	-	-	-	-	-	-	280,141
3	Fuel stock	64,489	-	64,489	-	-	-	-	-	-	-	-	-	-	-	64,489
4	Materials and supplies	216,848	0	216,848	-	-	-	-	-	-	-	-	-	-	-	216,848
5	Allowances	14	-	14	-	-	-	-	-	-	-	-	-	-	-	14
6	Prepayments	933,004	-	933,004	-	-	-	-	842	-	-	-	-	-	842	933,846
7	Accrued revenue	329,191	-	329,191	-	-	-	-	-	-	-	-	-	-	-	329,191
8	Deferred taxes	272,280	-	272,280	-	-	-	-	-	-	-	-	-	-	-	272,280
9	Deferred debits	1,838,965	0	1,838,965	107,648	116,846	(9,749)	-	-	(7,251)	(24,540)	(1,026,419)	2,576	-	(840,887)	998,077
10	Total assets	3,971,323	0	3,971,323	107,648	116,846	(9,749)	-	842	(7,251)	(24,540)	(1,026,419)	2,576	13,994	(826,051)	3,145,271
11	Accounts payable	474,206	-	474,206	-	-	-	-	-	-	-	-	-	-	-	474,206
12	Customer deposits	22,955	(0)	22,955	-	-	-	-	-	-	-	-	-	-	-	22,955
13	Accrued interest	66,062		66,062	-	-	-	-	-	-	-	-	-	-	-	66,062
14	Dividends payable	24,539		24,539	-	-	-	-	-	-	-	-	-	-	-	24,539
15	Accrued taxes	286,120		286,120	-	-	-	(30,040)	-	-	-	-	-	-	(30,040)	256,080
16	Other liabilities	72,728		72,728	-	-	-	-	-	-	-	-	-	-	-	72,728
17	Deferred credits	105,777		105,777	-	-	(2,962)	-	-	-	-	-	-	-	(2,962)	102,814
18	Total liabilities	1,052,386	(0)	1,052,386	-	-	(2,962)	(30,040)	-	-	-	-	-	-	(33,002)	1,019,384
19	Total working capital	2,918,936	0	2,918,936	107,648	116,846	(6,786)	30,040	842	(7,251)	(24,540)	(1,026,419)	2,576	13,994	(793,049)	2,125,887

Notes

Col. (b): Exhibit No.: A-2 (PDD-6)
Col. (c): Col. (d) - Col. (b)
Col. (d): WP-PDD-10
Col. (e): WP-PDD-26
Col. (f): WP-PDD-27
Col. (g): WP-PDD-28
Col. (h): WP-PDD-29
Col. (i): WP-PDD-30
Col. (j): WP-PDD-31
Col. (k): WP-PDD-32
Col. (l): WP-PDD-33
Col. (m): WP-PDD-34
Col. (n), Line 1: Testimony of Company Witness M. Bleckman

Schedule: B-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Expenditures Summary
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-12 (PDD-35)
Schedule: B-5
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Witness: PDDaly
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Historical	Projected				Approved Capital Expenditures in U-21585	Projected Capital Expenditures in U-21585
Line No.	Description	Source	12 Months Ended 12/31/2024	12 Months Ending 12/31/2025	4 Months Ending 4/30/2026	16 Months Ending 4/30/2026	12 Months Ending 4/30/2027	12 Months Ending 2/28/2026	12 Months Ending 2/28/2026
1	Electric Distribution	Exhibit No.: A-12 (MPK-1), Sch 5.7	920,439	1,152,221	445,828	1,598,049	1,529,914	1,007,982	1,307,115
2	Streetlighting	Exhibit No.: A-12 (DAS-1), Sch 5.9	18,541	20,628	5,804	26,432	16,545	24,811	30,147
3	Generation	Exhibit No.: A-12 (RTB-3), Sch 5.2	145,252	193,846	81,562	275,408	188,638	525,877	600,484
4	Information Technology	Exhibit No.: A-12 (SHB-4), Sch 5.1	39,979	46,756	24,332	71,088	66,983	38,908	38,908
5	Security	Exhibit No.: A-12 (SHB-4), Sch 5.1	4,044	5,362	3,859	9,221	10,736	9,143	9,143
6	Electric Vehicles	Exhibit No.: A-12 (JAM-1), Sch 5.8	1,431	-	229	229	171	-	-
7	Operations Support	Exhibit No.: A-12 (QAG-1), Sch 5.6	21,298	15,573	8,955	24,528	28,041	11,332	40,293
8	Fleet Services	Exhibit No.: A-12 (QAG-2), Sch 5.6	16,628	21,581	4,368	25,949	67,947	21,778	21,778
9	Corporate	Exhibit No.: A-12 (MJF-6), Sch 5.4	1,010	1,031	347	1,378	1,064	572	572
10	Customer Experience & Operations	Exhibit No.: A-12 (JRB-1), Sch 5.3	1,245	13	680	693	1,870	-	-
11	Demand Response	Exhibit No.: A-12 (AMG-1), Sch 5.5	5,156	2,006	268	2,274	1,555	909	909
12	Total capital expenditures		1,175,023	1,459,018	576,232	2,035,250	1,913,464	1,641,310	2,049,347

Notes

Schedule B-5.1

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

Case No.: U-21870
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Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period 12 Mos Ending 12/31/2025	(d) Projected Bridge Period 4 Mos Ending 4/30/2026	(e) Projected Bridge Period 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	**Corporate**	**$ 912**	**$ 3,048**	**$ 535**	**$ 3,583**	**$ 1,554**
	Labor	166	1,825	335	2,160	986
	Software	254	-	-	-	-
	Materials	2	27	22	49	44
	Contractor	436	199	-	199	-
	Non-Labor Overhead	-	169	23	192	69
	Non-Labor Other	54	828	155	983	455
	Contingency	-	-	-	-	-
2	**Customer**	**$ 1,489**	**$ 6,675**	**$ 1,164**	**$ 7,839**	**$ 3,668**
	Labor	365	2,938	310	3,248	782
	Software	179	(123)	-	(123)	-
	Materials	-	-	2	2	6
	Contractor	827	2,051	625	2,675	2,300
	Non-Labor Overhead	-	231	25	256	87
	Non-Labor Other	118	1,578	203	1,781	492
	Contingency	-	-	-	-	-
3	**Electric**	**$ 8,196**	**$ 11,837**	**$ 1,370**	**$ 13,206**	**$ 6,123**
	Labor	1,522	4,620	768	5,388	2,274
	Software	3,469	1,348	-	1,348	1,669
	Materials	1,183	1,546	0	1,546	1
	Contractor	1,456	1,497	138	1,635	814
	Non-Labor Overhead	-	517	69	586	206
	Non-Labor Other	565	2,309	394	2,703	1,159
	Contingency	-	-	-	-	-
4	**Electric & Gas Shared**	**$ 3,691**	**$ 1,139**	**$ 281**	**$ 1,419**	**$ 882**
	Labor	691	233	62	295	155
	Software	531	-	-	-	-
	Materials	152	52	2	54	69
	Contractor	1,963	489	164	653	493
	Non-Labor Overhead	-	58	14	72	41
	Non-Labor Other	354	306	39	345	124
	Contingency	-	-	-	-	-
5	**IT/Digital Foundation**	**$ 25,691**	**$ 24,058**	**$ 20,983**	**$ 45,040**	**$ 54,757**
	Labor	2,622	4,172	2,660	6,832	6,904
	Software	1,153	178	6,617	6,795	17,101
	Materials	12,420	10,963	4,927	15,891	13,938
	Contractor	8,428	6,237	4,745	10,981	11,595
	Non-Labor Overhead	-	587	322	909	932
	Non-Labor Other	1,067	1,920	1,712	3,632	4,286
	Contingency	-	-	-	-	-
6	**Security**	**$ 4,044**	**$ 5,362**	**$ 3,859**	**$ 9,221**	**$ 10,736**
	Labor	274	967	351	1,318	1,129
	Software	1,729	192	1,096	1,288	2,300
	Materials	1,456	2,078	1,187	3,265	3,597
	Contractor	620	1,251	844	2,095	2,649
	Non-Labor Overhead	-	565	24	588	70
	Non-Labor Other	(36)	309	359	667	990
	Contingency	-	-	-	-	-
7	**Total Information Technology Capital**	**$ 44,023**	**$ 52,118**	**$ 28,191**	**$ 80,310**	**$ 77,719**
	Labor	5,641	14,755	4,485	19,241	12,230
	Software	7,316	1,595	7,712	9,307	21,070
	Materials	15,213	14,667	6,140	20,808	17,654
	Contractor	13,730	11,724	6,516	18,239	17,852
	Non-Labor Overhead	-	2,128	477	2,604	1,406
	Non-Labor Other	2,123	7,249	2,861	10,111	7,507
	Contingency	-	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION **Schedule B-5.1**

Consumers Energy Company

Summary of Actual & Projected Electric and Common Capital Expenditures

Information Technology

($000)

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Line No	(a)	(b)	(c)	(d)	(e)
			Projected		
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
8	**Corporate**	**$ 1,016**	**$ 2,567**	**$ 1,554**	**$ 4,895**
	Labor	608	1,552	986	2,988
	Software	-	-	-	-
	Materials	9	40	44	93
	Contractor	66	133	-	199
	Non-Labor Overhead	56	136	69	250
	Non-Labor Other	276	707	455	1,365
	Contingency	-	-	-	-
9	**Customer**	**$ 2,225**	**$ 5,614**	**$ 3,668**	**$ 10,837**
	Labor	979	2,269	782	3,949
	Software	(41)	(82)	-	(123)
	Materials	-	2	6	7
	Contractor	684	1,992	2,300	4,450
	Non-Labor Overhead	77	179	87	325
	Non-Labor Other	526	1,255	492	2,230
	Contingency	-	-	-	-
10	**Electric**	**$ 3,946**	**$ 9,261**	**$ 6,123**	**$ 17,638**
	Labor	1,540	3,848	2,274	7,294
	Software	449	898	1,669	2,182
	Materials	515	1,031	1	1,547
	Contractor	499	1,136	814	2,180
	Non-Labor Overhead	172	414	206	758
	Non-Labor Other	770	1,933	1,159	3,676
	Contingency	-	-	-	-
11	**Electric & Gas Shared**	**$ 380**	**$ 1,040**	**$ 882**	**$ 2,141**
	Labor	78	217	155	434
	Software	-	-	-	-
	Materials	17	37	69	91
	Contractor	163	490	493	1,064
	Non-Labor Overhead	19	52	41	106
	Non-Labor Other	102	243	124	446
	Contingency	-	-	-	-
12	**IT/Digital Foundation**	**$ 5,025**	**$ 40,015**	**$ 54,757**	**$ 93,401**
	Labor	742	6,090	6,904	12,944
	Software	59	6,736	17,101	21,962
	Materials	3,429	12,461	13,938	27,787
	Contractor	394	10,588	11,595	21,524
	Non-Labor Overhead	84	825	932	1,697
	Non-Labor Other	316	3,316	4,286	7,488
	Contingency	-	-	-	-
13	**Security**	**$ 1,787**	**$ 7,434**	**$ 10,736**	**$ 18,448**
	Labor	322	995	1,129	2,233
	Software	64	1,224	2,300	3,534
	Materials	693	2,572	3,597	6,250
	Contractor	417	1,678	2,649	4,264
	Non-Labor Overhead	188	400	70	647
	Non-Labor Other	103	564	990	1,521
	Contingency	-	-	-	-
14	**Total Information Technology Capital**	**$ 14,378**	**$ 65,931**	**$ 77,719**	**$ 147,360**
	Labor	4,270	14,971	12,230	29,841
	Software	532	8,776	21,070	27,555
	Materials	4,664	16,144	17,654	35,775
	Contractor	2,223	16,017	17,852	33,681
	Non-Labor Overhead	598	2,007	1,406	3,784
	Non-Labor Other	2,093	8,018	7,507	16,725
	Contingency	-	-	-	-

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MICHIGAN PUBLIC SERVICE COMMISSION

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Generation Capital Expenditures
($000)

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2024	(c) Projected Bridge Period 12 Mos Ended 12/31/2025	(d) Projected Bridge Period 4 Mos Ending 4/30/2026	(e) Projected Bridge Period 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	Steam Power Generation					
2	Environmental	$ -	$ -	$ -	$ -	$ -
3	Routine and Small CapEx	$ 22,814	$ 9,200	$ 3,278	$ 12,478	$ 8,304
4	Total Steam Production	$ 22,814	$ 9,200	$ 3,278	$ 12,478	$ 8,304
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	$ 2,710	$ 11,418	$ 3,807	$ 15,225	$ 13,282
11	Total Pumped Storage Generation	$ 2,710	$ 11,418	$ 3,807	$ 15,225	$ 13,282
12	Other Production Plant					
13	Routine and Small CapEx	$ 119,728	$ 173,227	$ 74,477	$ 247,705	$ 167,051
14	Total Other Production Plant	$ 119,728	$ 173,227	$ 74,477	$ 247,705	$ 167,051
15	SubTotal	$ 145,252	$ 193,846	$ 81,562	$ 275,408	$ 188,638
16	Less Contingency	$ -	$ -	$ -	$ -	$ -
17	Grand Total	$ 145,252	$ 193,846	$ 81,562	$ 275,408	$ 188,638

Line No.	(a) Description	(b) Projected 4 Mos Ending 4/30/2025	(c) Projected 12 Mos Ending 4/30/2026	(d) Projected 12 Mos Ending 4/30/2027	(e) Projected 28 Mos Ending 4/30/2027
1	Steam Power Generation				
2	Environmental	$ -	$ -	$ -	$ -
3	Routine and Small CapEx	$ 1,763	$ 10,715	$ 8,304	$ 20,782
4	Total Steam Production	$ 1,763	$ 10,715	$ 8,304	$ 20,782
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	$ 3,928	$ 11,296	$ 13,282	$ 28,507
11	Total Pumped Storage Generation	$ 3,928	$ 11,296	$ 13,282	$ 28,507
12	Other Production Plant				
13	Routine and Small CapEx	$ 89,789	$ 157,916	$ 167,051	$ 414,755
14	Total Other Production Plant	$ 89,789	$ 157,916	$ 167,051	$ 414,755
15	SubTotal	$ 95,480	$ 179,928	$ 188,638	$ 464,045
16	Less Contingency	$ -	$ -	$ -	$ -
17	Grand Total	$ 95,480	$ 179,928	$ 188,638	$ 464,045

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Generation Capital Expenditures

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2024	(c)	(d) Projected Bridge Period 12 Months Ending 12/31/2025	(e)	(f) Projected Bridge Period 4 Months Ending 4/30/2026	(g)	(h) Projected Bridge Period 16 Months Ending 4/30/2026	(i)	(j) Projected Test Year 12 Months Ending 4/30/2027	(k)
1	**JHCampbell 1&2**	**$ (1,510)**		**$ -**		**$ -**		**$ -**		**$ -**	
2	Contractor		$ (1,274)		$ -		$ -		$ -		$ -
3	Labor		$ (193)		$ -		$ -		$ -		$ -
4	Materials		$ 131		$ -		$ -		$ -		$ -
5	Business Expenses		$ (20)		$ -		$ -		$ -		$ -
6	Contingency		$ -		$ -		$ -		$ -		$ -
7	Other (Loadings, Chargebacks)		$ (154)		$ -		$ -		$ -		$ -
8	**JHCampbell 3**	**$ (1,264)**		**$ -**		**$ -**		**$ -**		**$ -**	
9	Contractor		$ (1,007)		$ -		$ -		$ -		$ -
10	Labor		$ (200)		$ -		$ -		$ -		$ -
11	Materials		$ 150		$ -		$ -		$ -		$ -
12	Business Expenses		$ (36)		$ -		$ -		$ -		$ -
13	Contingency		$ -		$ -		$ -		$ -		$ -
14	Other (Loadings, Chargebacks)		$ (171)		$ -		$ -		$ -		$ -
15	**DEKarn 1&2**	**$ -**		**$ -**		**$ -**		**$ -**		**$ -**	
16	Contractor		$ -		$ -		$ -		$ -		$ -
17	Labor		$ -		$ -		$ -		$ -		$ -
18	Materials		$ -		$ -		$ -		$ -		$ -
19	Business Expenses		$ -		$ -		$ -		$ -		$ -
20	Contingency		$ -		$ -		$ -		$ -		$ -
21	Other (Loadings, Chargebacks)		$ -		$ -		$ -		$ -		$ -
22	**DEKarn 3&4**	**$ 25,587**		**$ 9,200**		**$ 3,278**		**$ 12,478**		**$ 8,304**	
23	Contractor		$ 18,333		$ 8,648		$ 3,081		$ 11,729		$ 7,806
24	Labor		$ 937		$ -		$ -		$ -		$ -
25	Materials		$ 1,450		$ -		$ -		$ -		$ -
26	Business Expenses		$ 56		$ -		$ -		$ -		$ -
27	Contingency		$ -		$ -		$ -		$ -		$ -
28	Other (Loadings, Chargebacks)		$ 4,812		$ 552		$ 197		$ 749		$ 498
29	**Zeeland**	**$ 45,025**		**$ 52,002**		**$ 15,273**		**$ 67,275**		**$ 40,023**	
30	Contractor		$ 34,570		$ 48,882		$ 14,356		$ 63,239		$ 37,621
31	Labor		$ 588		$ -		$ -		$ -		$ -
32	Materials		$ 3,250		$ -		$ -		$ -		$ -
33	Business Expenses		$ 67		$ -		$ -		$ -		$ -
34	Contingency		$ -		$ -		$ -		$ -		$ -
35	Other (Loadings, Chargebacks)		$ 6,550		$ 3,120		$ 916		$ 4,037		$ 2,401
36	**Jackson Generating Station**	**$ 15,255**		**$ 18,778**		**$ 5,712**		**$ 24,489**		**$ 28,143**	
37	Contractor		$ 11,661		$ 17,651		$ 5,369		$ 23,020		$ 26,455
38	Labor		$ 273		$ -		$ -		$ -		$ -
39	Materials		$ 1,539		$ -		$ -		$ -		$ -
40	Business Expenses		$ 5		$ -		$ -		$ -		$ -
41	Contingency		$ -		$ -		$ -		$ -		$ -
42	Other (Loadings, Chargebacks)		$ 1,777		$ 1,127		$ 343		$ 1,469		$ 1,689
43	**Covert**	**$ 30,712**		**$ 45,054**		**$ 22,491**		**$ 67,545**		**$ 61,443**	
44	Contractor		$ 23,628		$ 42,350		$ 21,142		$ 63,492		$ 57,756
45	Labor		$ 113		$ -		$ -		$ -		$ -
46	Materials		$ 3,377		$ -		$ -		$ -		$ -
47	Business Expenses		$ 26		$ -		$ -		$ -		$ -
48	Contingency		$ -		$ -		$ -		$ -		$ -
49	Other (Loadings, Chargebacks)		$ 3,568		$ 2,703		$ 1,349		$ 4,053		$ 3,687

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Historical Year		Projected Bridge Period						Projected Test Year	
Line No.	Description	12 Months Ended 12/31/2024		12 Months Ending 12/31/2025		4 Months Ending 4/30/2026		16 Months Ending 4/30/2026		12 Months Ending 4/30/2027	
50	**Hydros**	**-**		**-**		**-**		**-**		**-**	
51	Contractor		-		-		-		-		-
52	Labor		-		-		-		-		-
53	Materials		-		-		-		-		-
54	Business Expenses		-		-		-		-		-
55	Contingency		-		-		-		-		-
56	Other (Loadings, Chargebacks)		-		-		-		-		-
57	**Ludington**	**2,710**		**11,418**		**3,807**		**15,225**		**13,282**	
58	Contractor		3,299		18,041		6,015		24,055		20,986
59	Labor		402		-		-		-		-
60	Materials		885		-		-		-		-
61	Business Expenses		449		-		-		-		-
62	Contingency		-		-		-		-		-
63	Other (Loadings, Chargebacks)		(2,325)		(6,622)		(2,208)		(8,830)		(7,704)
64	**Admin and Other**	**5,748**		**14,809**		**2,973**		**17,782**		**11,050**	
65	Contractor		3,476		12,564		2,585		15,149		9,550
66	Labor		92		-		-		-		-
67	Materials		2,149		-		-		-		-
68	Business Expenses		79		-		-		-		-
69	Contingency		-		-		-		-		-
70	Other (Loadings, Chargebacks)		(48)		2,244		388		2,633		1,501
71	**Battery Storage**	**22,988**		**42,585**		**28,029**		**70,614**		**26,392**	
72	Contractor		16,777		36,470		24,004		60,473		22,602
73	Labor		207		-		-		-		-
74	Materials		2,475		-		-		-		-
75	Business Expenses		5		-		-		-		-
76	Contingency		-		-		-		-		-
77	Other (Loadings, Chargebacks)		3,525		6,115		4,025		10,140		3,790
78	**All Other Environmental**	**-**		**-**		**-**		**-**		**-**	
79	Contractor		-		-		-		-		-
80	Labor		-		-		-		-		-
81	Materials		-		-		-		-		-
82	Business Expenses		-		-		-		-		-
83	Contingency		-		-		-				-
84	Other (Loadings, Chargebacks)		-		-		-		-		-
85	**Total Capital**	145,252	145,252	193,846	193,846	81,562	81,562	275,408	275,408	188,638	188,638

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MICHIGAN PUBLIC SERVICE COMMISSION

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
			Projected		
Line No.	**Description**	**4 Mos Ending 4/30/2025**	**12 Mos Ending 4/30/2026**	**12 Mos Ending 4/30/2027**	**28 Mos Ending 4/30/2027**
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**	**$ 1,763**	**$ 10,715**	**$ 8,304**	**$ 20,782**
23	Contractor	$ 1,635	$ 10,094	$ 7,806	$ 19,535
24	Labor	$ -	$ -	$ -	$ -
25	Materials	$ -	$ -	$ -	$ -
26	Business Expenses	$ -	$ -	$ -	$ -
27	Contingency	$ -	$ -	$ -	$ -
28	Other (Loadings, Chargebacks)	$ 127	$ 621	$ 498	$ 1,247
29	**Zeeland**	**$ 33,232**	**$ 34,043**	**$ 40,023**	**$ 107,298**
30	Contractor	$ 32,099	$ 31,140	$ 37,621	$ 100,860
31	Labor	$ -	$ -	$ -	$ -
32	Materials	$ -	$ -	$ -	$ -
33	Business Expenses	$ -	$ -	$ -	$ -
34	Contingency	$ -	$ -	$ -	$ -
35	Other (Loadings, Chargebacks)	$ 1,133	$ 2,903	$ 2,401	$ 6,438
36	**Jackson Generating Station**	**$ 4,499**	**$ 19,991**	**$ 28,143**	**$ 52,633**
37	Contractor	$ 4,340	$ 18,680	$ 26,455	$ 49,475
38	Labor	$ -	$ -	$ -	$ -
39	Materials	$ -	$ -	$ -	$ -
40	Business Expenses	$ -	$ -	$ -	$ -
41	Contingency	$ -	$ -	$ -	$ -
42	Other (Loadings, Chargebacks)	$ 158	$ 1,311	$ 1,689	$ 3,158
43	**Covert**	**$ 16,058**	**$ 51,487**	**$ 61,443**	**$ 128,988**
44	Contractor	$ 14,977	$ 48,515	$ 57,756	$ 121,248
45	Labor	$ -	$ -	$ -	$ -
46	Materials	$ -	$ -	$ -	$ -
47	Business Expenses	$ -	$ -	$ -	$ -
48	Contingency	$ -	$ -	$ -	$ -
49	Other (Loadings, Chargebacks)	$ 1,080	$ 2,972	$ 3,687	$ 7,739

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Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
			Projected		
Line No.	**Description**	**4 Mos Ending 4/30/2025**	**12 Mos Ending 4/30/2026**	**12 Mos Ending 4/30/2027**	**28 Mos Ending 4/30/2027**
50	**Hydros**	**$ -**	**$ -**	**$ -**	**$ -**
51	Contractor	$ -	$ -	$ -	$ -
52	Labor	$ -	$ -	$ -	$ -
53	Materials	$ -	$ -	$ -	$ -
54	Business Expenses	$ -	$ -	$ -	$ -
55	Contingency	$ -	$ -	$ -	$ -
56	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
57	**Ludington**	**$ 3,928**	**$ 11,296**	**$ 13,282**	**$ 28,507**
58	Contractor	$ 6,865	$ 17,190	$ 20,986	$ 45,041
59	Labor	$ -	$ -	$ -	$ -
60	Materials	$ -	$ -	$ -	$ -
61	Business Expenses	$ -	$ -	$ -	$ -
62	Contingency	$ -	$ -	$ -	$ -
63	Other (Loadings, Chargebacks)	$ (2,937)	$ (5,893)	$ (7,704)	$ (16,534)
64	**Admin and Other**	**$ 2,477**	**$ 15,305**	**$ 11,050**	**$ 28,832**
65	Contractor	$ 2,145	$ 13,004	$ 9,550	$ 24,699
66	Labor	$ -	$ -	$ -	$ -
67	Materials	$ -	$ -	$ -	$ -
68	Business Expenses	$ -	$ -	$ -	$ -
69	Contingency	$ -	$ -	$ -	$ -
70	Other (Loadings, Chargebacks)	$ 332	$ 2,300	$ 1,501	$ 4,133
71	**Battery Storage**	**$ 33,523**	**$ 37,091**	**$ 26,392**	**$ 97,006**
72	Contractor	$ 28,709	$ 31,764	$ 22,602	$ 83,075
73	Labor	$ -	$ -	$ -	$ -
74	Materials	$ -	$ -	$ -	$ -
75	Business Expenses	$ -	$ -	$ -	$ -
76	Contingency	$ -	$ -	$ -	$ -
77	Other (Loadings, Chargebacks)	$ 4,814	$ 5,326	$ 3,790	$ 13,930
78	**All Other Environmental**	**$ -**	**$ -**	**$ -**	**$ -**
79	Contractor	$ -	$ -	$ -	$ -
80	Labor	$ -	$ -	$ -	$ -
81	Materials	$ -	$ -	$ -	$ -
82	Business Expenses	$ -	$ -	$ -	$ -
83	Contingency	$ -	$ -	$ -	$ -
84	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
85	**SubTotal**	$ 95,480	$ 179,928	$ 188,638	$ 464,045
86	**Less Contingency**	$ -	$ -	$ -	$ -
87	**Grand Total**	$ 95,480	$ 179,928	$ 188,638	$ 464,045

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Generation Capital Expenditures

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2024	(c) Projected Bridge Period 12 Months Ending 12/31/2025	(d) Projected Bridge Period 4 Months Ending 4/30/2026	(e) Projected Bridge Period 16 Months Ending 4/30/2026	(f) Projected Test Year 12 Months Ending 4/30/2027
1	Contractor	$ 109,462	$ 184,607	$ 76,551	$ 261,158	$ 182,776
2	Labor	$ 2,219	$ -	$ -	$ -	$ -
3	Materials	$ 15,405	$ -	$ -	$ -	$ -
4	Business Expenses	$ 632	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 17,533	$ 9,239	$ 5,011	$ 14,250	$ 5,862
	Total	$ 145,252	$ 193,846	$ 81,562	$ 275,408	$ 188,638

Line No.	(a) Description	(b) 12 Months Ended 12/31/2024	(c) Projected 4 Months Ending 4/30/2025	(d) Projected 16 Months Ending 4/30/2026	(e) Projected 12 Months Ending 4/30/2027	(f) Projected 28 Months Ending 4/30/2027
1	Contractor	$ 109,462	$ 90,771	$ 261,158	$ 182,776	$ 443,934
2	Labor	$ 2,219	$ -	$ -	$ -	$ -
3	Materials	$ 15,405	$ -	$ -	$ -	$ -
4	Business Expenses	$ 632	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 17,533	$ 4,709	$ 14,250	$ 5,862	$ 20,111
	Total	$ 145,252	$ 95,480	$ 275,408	$ 188,638	$ 464,045

Schedule: B-5.2

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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	2024	Gas Generation	Covert	Non-Routine	Condition-based	Long Term Service Agreement - Running capital contrac	$ 19,004	$ 15,623
2	2024	Gas Generation	Covert	Routine	Condition-based	Netmation (MHPSA Operating System & 4S) - Unit 1-3	$ 4,596	$ 6,047
3	2024	Gas Generation	Covert	Routine	Environmental	Long Term Service Agreement - Extra Work Unit 2	$ 750	$ 1,340
4	2024	Gas Generation	Covert	Routine	Environmental	HRSG Expansion Joint Replacements	$ -	$ 1,284
5	2024	Gas Generation	Jackson	Routine	Condition-based	1-6 Feedwater Desuperheater Valve	$ 831	$ 1,871
6	2024	Gas Generation	Jackson	Routine	Condition-based	GE Long Term Service Agreement FFH	$ 12,213	$ 8,615
7	2024	Gas Generation	Zeeland	Non-Routine	Condition-based	Unit 5 generator step up transformer rewinc	$ 9,135	$ 9,696
8	2024	Gas Generation	Zeeland	Non-Routine	Condition-based	Site Spare GSU	$ 590	$ 2,040
9	2024	Gas Generation	Zeeland	Routine	Condition-based	P2 599 699 345kV Breaker Replcmnt	$ 320	$ 1,856
10	2024	Gas Generation	Zeeland	Routine	Condition-based	Zeeland Long Term Service Agreement - Running Capital Contrac	$ 19,641	$ 21,699
11	2024	Gas Generation	Zeeland	Non-Routine	Condition-based	Heat recovery steam generator Casing Replacemen	$ 2,739	$ 2,840
12	2024	Gas/Oil Generation	Karn 3	Routine	Condition-based	Karn 3 distributed control system Evergreer	$ 1,295	$ 1,191
13	2024	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Karn 3 Cooling Tower Internal Structure Replacemen	$ 3,919	$ 4,183
14	2024	Gas/Oil Generation	Karn 3	Routine	Condition-based	Karn 3 Combustion Air Heater	$ 2,500	$ 1,354
15	2024	Gas/Oil Generation	Karn commons	Routine	Condition-based	Karn 3&4 Sync Wire Replacement	$ 1,458	$ 1,260
16	2024	Gas/Oil Generation	Karn commons	Non-Routine	Condition-based	Boiler Plant Heating Project	$ 3,055	$ 4,467
17	2024	Gas/Oil Generation	Karn commons	Non-Routine	Condition-based	Karn 3&4 Tank Farm Heating Line Replacemen	$ 1,230	$ 1,217
18	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	New Electrical System from Weadock Sub for Karn 3 and 4	$ -	$ 1,524
19	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	Discharge Line Reroute for K 3 and 4 Sump Water	$ -	$ 1,905
20	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	New building to house new fire water system	$ -	$ 1,019
21	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	New 46kV to 4160 transformer to repower facilities	$ -	$ 3,065
22	2024	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Iosco Battery Energy Storage System (IRP)	$ 21,458	$ 9,107
23	2024	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Weadock Battery Energy Storage System (IRP)	$ 31,819	$ 13,011
24	**Total 2024 Projects**						**$ 136,553**	**$ 116,212**

Note:
(1) Projected amounts were taken from Case No. U-21585, Staff Exhibit S-16.1 Page 1 of 2 and workpapers.

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Generation Capital Expenditures

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	Non-Routine	Condition-based	Class 2	Approved	Purchase of site spare GSU	$1,500
2	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 3	Approved	LCI Replacements (SFC)	$1,305
3	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 2	Approved	Units 1-3 Emerson DCS Evergreen	$2,156
4	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	Long Term Service Agreement - Running capital contract	$26,246
5	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 2	Approved	Netmation (MHPSA Operating System & 4S) - Units 1-3	$2,922
6	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 2 - LTSA Capital - Extra work not included in contract	$12,153
7	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 3 - LTSA Capital - Extra work not included in contract	$9,010
8	Bridge Period	Gas Generation	Jackson	Non-Routine	Condition-based	Class 3	Approved	Purchase of site spare GSU	$1,333
9	Bridge Period	Gas Generation	Jackson	Non-Routine	Condition-based	Class 3	Approved	LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement	$1,336
10	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	GE Long Term Service Agreement FFH	$16,200
11	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	LTSA Capital - Extra work not included in contract	$2,115
12	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel staging	$43,697
13	Bridge Period	Gas Generation	Zeeland	Routine	Condition-based	Class 3	Approved	LTSA - Extras not included in contract (cranes, mobile equipment)	$4,703
14	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 3	Approved	Phase II Turbine Replacements	$10,175
15	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Purchase of Site Spare Generator Step up transformer	$2,341
16	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	Unit 5 GSU Transformer Rewind	$2,430
17	Bridge Period	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement	$2,700
18	Bridge Period	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 2	Approved	ID Fan Inlet Damper Replacements	$2,700
19	Bridge Period	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement	$3,000
20	Bridge Period	Gas/Oil Generation	Karn Commons	Non-Routine	Condition-based	Class 3	Approved	Karn 3&4 Ductwork Expansion Joint Replacement - ID Fans to Stack	$1,800
21	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1-6 DCS Control Relay Replacement	$2,972
22	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1 Pony Motor Overhaul	$2,267
23	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington Governor Replacement	$2,026
24	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 480 Volt Motor Control Centers for DLC	$1,288
25	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Replace Lower Penstock Expansion Joint	$2,010
26	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Station Water Discharge Isolation Valve	$1,161
27	Bridge Period	Admininstration	Admin	Non-Routine	Environmental	Class 2	Approved	Wastewater Treatment System	$12,400
28	Bridge Period	Admininstration	Admin	Non-Routine	Infrastructure	Class 2	Approved	Lakeshore Admin Building	$3,702
29	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Iosco Battery Energy Storage System (IRP)	$30,053
30	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Weadock Battery Energy Storage System (IRP)	$40,561
31	**Total Bridge Period Projects**								**$248,262**

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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) 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 2	Approved	Purchase of site spare GSU	$5,910
2	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Class 3	Approved	LCI Replacements (SFC)	$2,610
3	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	Long Term Service Agreement - Running capital contract	$18,812
4	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 2	Approved	Netmation (MHPSA Operating System & 4S) - Units 1-3	$8,844
5	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 1 - LTSA Capital - Extra work not included in contract	$9,525
6	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 3 - LTSA Capital - Extra work not included in contract	$4,093
7	Test Year	Gas Generation	Jackson	Non-Routine	Condition-based	Class 3	Approved	Purchase of site spare GSU	$2,333
8	Test Year	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	GE Long Term Service Agreement FFH	$12,810
9	Test Year	Gas Generation	Jackson	Routine	Condition-based	Class 3	Approved	Engine 191-306 Overhaul	$6,130
10	Test Year	Gas Generation	Jackson	Routine	Condition-based	Class 3	Approved	Unit 7 gas turbine rotor replacement	$1,664
11	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel sta	$8,331
12	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 3	Approved	Phase II Turbine Replacements	$10,175
13	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Phase II GT Advanced gas path replacement and axial fuel staging	$13,923
14	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Purchase of Site Spare Generator Step up transformer	$4,481
15	Test Year	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement	$1,800
16	Test Year	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement	$2,250
17	Test Year	Gas/Oil Generation	Karn Commons	Non-Routine	Condition-based	Class 3	Approved	Karn 3&4 Ductwork Expansion Joint Replacement - ID Fans to Stack	$1,800
18	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1 Pony Motor Overhaul	$2,800
19	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1-6 DCS Control Relay Replacement	$2,907
20	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington Governor Replacement	$2,126
21	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 480 Volt Motor Control Centers for DLC	$1,352
22	Test Year	Admininstration	Admin	Non-Routine	Environmental	Class 2	Approved	Wastewater Treatment System	$9,600
23	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Iosco Battery Energy Storage System (IRP)	$11,457
24	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Weadock Battery Energy Storage System (IRP)	$14,934
25	**Total Test Year Projects**								**$160,668**

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MICHIGAN PUBLIC SERVICE COMMISSION
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Customer Experience & Operations
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	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Customer Billing	1,231	13	0	13	0
2	Analytics & Outreach	14	0	0	0	0
3	Credit & Assistance	0	0	680	680	1,870
4	Demand Response (C&I)	287	1,350	60	1,410	180
5	Demand Response (Res)	4,868	656	208	864	1,375
6	PowerMiDrive	1,162	0	229	229	171
7	PowerMiFleet	269	0	0	0	0
8	Total Capital	7,831	2,019	1,177	3,196	3,596

		Projected			
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
9	Customer Billing	13	0	0	13
10	Analytics & Outreach	0	0	0	0
11	Credit & Assistance	0	680	1,870	2,550
12	Demand Response (C&I)	450	960	180	1,590
13	Demand Response (Res)	202	662	1,375	2,239
14	PowerMiDrive	0	229	171	400
15	PowerMiFleet	0	0	0	0
16	Total Capital	665	2,531	3,596	6,792

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Line No	Description	(a) Historical Year 12 Mos Ended 12/31/2024	(b) Projected Bridge Year 12 Mos Ending 12/31/2025	(c) Projected Bridge Year 4 Mos Ending 4/30/2026	(d) Projected Bridge Year 16 Mos Ending 4/30/2026	(e) Projected Test Year 12 Mos Ending 4/30/2027
1	Customer Billing	1,231	13	0	13	0
	Labor	-	-	-	-	-
	Capitalized E&S	-	-	-	-	-
	Materials	-	-	-	-	-
	Contractor	1,231	13	-	13	-
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	-	-	-	-	-
	Contingency	-	-	-	-	-
2	Analytics & Outreach	14	0	0	0	0
	Labor	-	-	-	-	-
	Capitalized E&S	-	-	-	-	-
	Materials	-	-	-	-	-
	Contractor	14	-	-	-	-
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	-	-	-	-	-
	Contingency	-	-	-	-	-
3	Credit & Assistance	0	0	680	680	1,870
	Labor	-	-	-	-	-
	Capitalized E&S	-	-	-	-	-
	Materials	-	-	-	-	-
	Contractor	-	-	680	680	1,870
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	-	-	-	-	-
	Contingency	-	-	-	-	-
4	Total Customer Experience & Operations Capital	1,245	13	680	693	1,870
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	0	0	0	0	0
	Contractor	1,245	13	680	693	1,870
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0

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	(a)	(b)	(c)	(d)	(e)
			Projected		
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
5	Customer Billing	13	0	0	13
	Labor	-	-	-	-
	Capitalized E&S	-	-	-	-
	Materials	-	-	-	-
	Contractor	13	-	-	13
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	-	-	-	-
	Contingency	-	-	-	-
6	Analytics & Outreach	0	0	0	0
	Labor	-	-	-	-
	Capitalized E&S	-	-	-	-
	Materials	-	-	-	-
	Contractor	-	-	-	-
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	-	-	-	-
	Contingency	-	-	-	-
7	Credit & Assistance	0	680	1,870	2,550
	Labor	-	-	-	-
	Capitalized E&S	-	-	-	-
	Materials	-	-	-	-
	Contractor	-	680	1,870	2,550
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	-	-	-	-
	Contingency	-	-	-	-
8	Total Customer Experience & Operations Capital	13	680	1,870	2,563
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	0	0
	Contractor	13	680	1,870	2,563
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0

Schedule: B-5.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Electric Corporate Services Capital Expenditures
($000)

Case No.: U-21870
Exhibit No.: A-12 (MJF-6)
Schedule: B-5.4
Page: 1 of 1
Witness: MJFoster
Date: June 2025

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period 12 Mos Ending 12/31/2025	(d) Projected Bridge Period 4 Mos Ending 4/30/2026	(e) Projected Bridge Period 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	Corporate Capital	1,010	1,031	347	1,378	1,064
	Contractor	587	599	201	800	619
	Labor	73	75	25	100	77
	Materials	223	228	77	305	235
	Business Expenses	127	130	44	174	134
	Contingency	-	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-	-
2	**Total Capital**	1,010	1,031	347	1,378	1,064

		Projected 4 Mos Ending 4/30/2025	Projected 12 Mos Ending 4/30/2026	Projected 12 Mos Ending 4/30/2027	Projected 28 Mos Ending 4/30/2027
3	Corporate Capital	344	1,034	1,064	2,443
	Contractor	200	601	619	1,420
	Labor	25	75	77	177
	Materials	76	228	235	539
	Business Expenses	43	130	134	307
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-
4	**Total Capital**	344	1,034	1,064	2,443

		2025	2026	2027
5	Annual inflation rates per WP-PDD-37			
	Annual inflation rates	2.1%	2.4%	2.4%
	Number of months in the period	12	12	4
	Pro-rated inflation rate	2.1%	2.4%	0.8%

Schedule: B-5.5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
For Demand Response C&I and Residential Programs
($000)

Case No.: U-21870
Exhibit No.: A-12 (AMG-1)
Schedule: B-5.5
Page: 1 of 1
Witness: AMGast
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2024	12 Mos Ending 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Demand Response (C&I)	287	1,350	60	1,410	180
	Labor	-	-	-	-	-
	Capitalized E&S	-	-	-	-	-
	Materials	287	1,350	60	1,410	180
	Contractor	-	-	-	-	-
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	-	-	-	-	-
	Contingency	-	-	-	-	-
2	Demand Response (Res)	4,868	656	208	864	1,375
	Labor	-	-	-	-	-
	Capitalized E&S	-	-	-	-	-
	Materials	4,868	656	208	864	1,375
	Contractor	-	-	-	-	-
	Non-Labor Overhead	-	-	-	-	-
	Non-Labor Other	-	-	-	-	-
	Contingency	-	-	-	-	-
3	Total Demand Response Capital	5,156	2,006	268	2,274	1,555
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	5,156	2,006	268	2,274	1,555
	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

Schedule: B-5.5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
For Demand Response C&I and Residential Programs
($000)

Case No.: U-21870
Exhibit No.: A-12 (AMG-1)
Schedule: B-5.5
Page: 2 of 2
Witness: AMGast
Date: June 2025

	(a)	(b)	(c)	(d)	(e)
			Projected		
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
4	Demand Response (C&I)	450	960	180	1,590
	Labor	-	-	-	-
	Capitalized E&S	-	-	-	-
	Materials	450	960	180	1,590
	Contractor	-	-	-	-
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	-	-	-	-
	Contingency	-	-	-	-
5	Demand Response (Res)	202	662	1,375	2,239
	Labor	-	-	-	-
	Capitalized E&S	-	-	-	-
	Materials	202	662	1,375	2,239
	Contractor	-	-	-	-
	Non-Labor Overhead	-	-	-	-
	Non-Labor Other	-	-	-	-
	Contingency	-	-	-	-
6	Total Demand Response Capital	652	1,622	1,555	3,829
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	652	1,622	1,555	3,829
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0

Schedule: B-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Facilities & Shared Services
($000)

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
Page: 1 of 6
Witness: QAGuinn
Date: June 2025

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period* 12 Mos Ended 12/31/2025	(d) Projected Bridge Period* 4 Mos Ending 4/30/2026	(e) Projected Bridge Period* 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	Asset Preservation	20,940	14,903	8,787	23,690	27,371
2	Other Equipment	357	670	168	838	670
3	Total Facilities & Shared Services	21,298	15,573	8,955	24,528	28,041

		Projected 4 Mos Ending 4/30/2025	Projected 12 Mos Ending 4/30/2026	Projected 12 Mos Ending 4/30/2027	Projected 28 Mos Ending 4/30/2027
4	Asset Preservation	4,738	18,953	27,371	51,062
5	Other Equipment	168	670	670	1,508
6	Total Facilities & Shared Services	4,905	19,623	28,041	52,569

**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-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Facilities & Shared Services
($000)

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
Page: 2 of 6
Witness: QAGuinn
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year*			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2024	12 Mos Ending 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	**Asset Preservation**	**20,940**	**14,903**	**8,787**	**23,690**	**27,371**
	Labor	1,068	835	492	1,327	1,533
	Capitalized E&S	0	0	0	0	0
	Materials	2,115	1,013	598	1,611	1,861
	Contractor	16,669	12,236	7,214	19,450	22,472
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	1,089	820	483	1,303	1,505
	Contingency	0	0	0	0	0
2	**Other Equipment**	**357**	**670**	**168**	**838**	**670**
	Labor	3	7	2	8	7
	Capitalized E&S	0	0	0	0	0
	Materials	254	483	121	603	483
	Contractor	73	134	34	168	134
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	28	47	12	59	47
	Contingency	0	0	0	0	0
3	**Total Facilities & Shared Services**	**21,298**	**15,573**	**8,955**	**24,528**	**28,041**
	Labor	1,071	841	494	1,335	1,539
	Capitalized E&S	0	0	0	0	0
	Materials	2,369	1,496	718	2,214	2,344
	Contractor	16,742	12,370	7,248	19,617	22,606
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	1,116	867	495	1,362	1,552
	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-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Facilities & Shared Services
($000)

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
Page: 3 of 6
Witness: QAGuinn
Date: June 2025

(a)	(b)	(c)	(d)	(e)
		Projected*		
	4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
4 Asset Preservation	**4,738**	**18,953**	**27,371**	**51,062**
Labor	265	1,061	1,533	2,859
Capitalized E&S	0	0	0	0
Materials	322	1,289	1,861	3,472
Contractor	3,890	15,560	22,472	41,922
Non-Labor Overhead	0	0	0	0
Non-Labor Other	261	1,042	1,505	2,808
Contingency	0	0	0	0
5 Other Equipment	**168**	**670**	**670**	**1,508**
Labor	2	7	7	15
Capitalized E&S	0	0	0	0
Materials	121	483	483	1,086
Contractor	34	134	134	302
Non-Labor Overhead	0	0	0	0
Non-Labor Other	12	47	47	106
Contingency	0	0	0	0
6 Total Facilities & Shared Services	**4,905**	**19,623**	**28,041**	**52,569**
Labor	267	1,068	1,539	2,875
Capitalized E&S	0	0	0	0
Materials	443	1,771	2,344	4,558
Contractor	3,923	15,694	22,606	42,223
Non-Labor Overhead	0	0	0	0
Non-Labor Other	272	1,089	1,552	2,914
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.).*

Schedule: B-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Fleet Services
($000)

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
Page: 4 of 6
Witness: QAGuinn
Date: June 2025

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period* 12 Mos Ending 12/31/2025	(d) Projected Bridge Period* 4 Mos Ending 4/30/2026	(e) Projected Bridge Period* 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	Fleet Vehicle Capital Replacement	16,293	19,882	4,282	24,164	20,778
2	Fleet Vehicle Electrification	0	800	0	800	840
3	Fleet Expansion	0	648	0	648	46,070
4	Fleet Business Partner Funded	55	0	0	0	0
5	Fleet Tools - Garage	280	251	86	336	259
6	Total Fleet Services Capital	16,628	21,581	4,368	25,948	67,947

Line No	Description	Projected* 4 Mos Ending 4/30/2025	Projected* 12 Mos Ending 4/30/2026	Projected* 12 Mos Ending 4/30/2027	Projected* 28 Mos Ending 4/30/2027
7	Fleet Vehicle Capital Replacement	5,470	19,494	20,778	45,742
8	Fleet Vehicle Electrification	0	0	840	840
9	Fleet Expansion	0	648	46,070	46,718
10	Fleet Business Partner Funded	0	0	0	0
11	Fleet Tools - Garage	84	253	259	595
12	Total Fleet Services Capital	5,554	20,394	67,947	93,895

**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-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Fleet Services
($000)

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
Page: 5 of 6
Witness: QAGuinn
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year*			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2024	12 Mos Ending 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	**Fleet Vehicle Capital Replacement**	**16,293**	**19,882**	**4,282**	**24,164**	**20,778**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	13,295	16,616	3,578	20,194	17,364
	Contractor	2,232	2,970	640	3,610	3,104
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	766	296	64	360	310
	Contingency	0	0	0	0	0
2	**Fleet Vehicle Electrification**	**0**	**800**	**0**	**800**	**840**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	0	800	0	800	840
	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
3	**Fleet Expansion**	**0**	**648**	**0**	**648**	**46,070**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	0	542	0	542	38,501
	Contractor	0	97	0	97	6,883
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	10	0	10	686
	Contingency	0	0	0	0	0
4	**Fleet Business Partner Funded**	**55**	**0**	**0**	**0**	**0**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	45	0	0	0	0
	Contractor	8	0	0	0	0
	Non-Labor Overhead		0	0	0	0
	Non-Labor Other	3	0	0	0	0
	Contingency	0	0	0	0	0
5	**Fleet Tools - Garage**	**280**	**251**	**86**	**336**	**259**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	280	251	86	336	259
	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
6	**Total Fleet Services Capital**	**16,628**	**21,581**	**4,368**	**25,948**	**67,947**
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	13,620	18,208	3,664	21,872	56,964
	Contractor	2,240	3,067	640	3,707	9,987
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	768	306	64	370	996
	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.).*

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Fleet Services
($000)

Case No.: U-21870
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
Page: 6 of 6
Witness: QAGuinn
Date: June 2025

	(a)	(b)	(c)	(d)	(e)
		Projected*			
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
7	**Fleet Vehicle Capital Replacement**	**5,470**	**19,494**	**20,778**	**45,742**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	4,571	16,291	17,364	38,226
	Contractor	817	2,912	3,104	6,834
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	82	290	310	682
	Contingency	0	0	0	0
8	**Fleet Vehicle Electrification**	**0**	**0**	**840**	**840**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	840	840
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
9	**Fleet Expansion**	**0**	**648**	**46,070**	**46,718**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	542	38,501	39,042
	Contractor	0	97	6,883	6,980
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	10	686	696
	Contingency	0	0	0	0
10	**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
11	**Fleet Tools - Garage**	**84**	**253**	**259**	**595**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	84	253	259	595
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
12	**Total Fleet Services Capital**	**5,554**	**20,394**	**67,947**	**93,895**
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	4,655	17,085	56,964	78,704
	Contractor	817	3,009	9,987	13,813
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	82	300	996	1,378
	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.).*

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Distribution Summary of Actual and Projected Capital Expenditures
($000)

Case No.: U-21870
Exhibit No.: A-12 (MPK-1)
Schedule: B-5.7
Page: 1 of 1
Witness: MPKelly
Date: June 2025

Line No	Description	(a)	(b) Historical Year	(c) Projected Bridge Period	(d) Projected Bridge Period	(e) Projected Bridge Period	(f) Projected Test Year
			12 Mos Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	New Business Program		308,029	358,808	133,700	492,508	389,759
2	Reliability Program		219,105	404,613	206,293	610,906	697,127
3	Capacity Program		98,235	109,131	33,785	142,916	140,809
4	Demand Failures Program		222,634	189,233	62,835	252,068	185,431
5	Asset Relocation Program		63,767	83,078	32,125	115,203	100,393
6	Electric Other Program		8,669	8,358	2,090	10,448	8,542
7	Wildfire Mitigation & Vulnerable Community		-	-	-	-	30,000
8	**Total Capital**		920,439	1,153,221	470,828	1,624,049	1,552,062
9	IIJA Grant Funding		-	(1,000)	(25,000)	(25,999)	(22,148)
10	**Total Capital net of IIJA Grants**		920,439	1,152,221	445,828	1,598,050	1,529,914

Line No	Description	Projected 4 Mos Ending 4/30/2025	Projected 12 Mos Ending 4/30/2026	Projected 12 Mos Ending 4/30/2027	Projected 26 Mos Ending 4/30/2027
11	New Business Program	119,603	372,905	389,759	882,267
12	Reliability Program	134,871	476,035	697,127	1,308,034
13	Capacity Program	36,377	106,539	140,809	283,725
14	Demand Failures Program	63,078	188,991	185,431	437,500
15	Asset Relocation Program	27,693	87,510	100,393	215,596
16	Electric Other Program	2,786	7,662	8,542	18,990
17	Wildfire Mitigation & Vulnerable Community	-	-	30,000	30,000
18	**Total Capital**	384,407	1,239,642	1,552,062	3,176,111
19	IIJA Grant Funding	(333)	(25,667)	(22,148)	(48,148)
20	**Total Capital net of IIJA Grants**	384,074	1,213,976	1,529,914	3,127,963

Schedule: B-5.8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Add Description
($000)

Case No.: U-21870
Exhibit No.: A-12 (JAM-1)
Schedule: B-5.8
Page: 1 of 3
Witness: JAMyrom
Date: June 2025

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2024	(c) Projected Bridge Period 12 Mos Ended 12/31/2025	(d) Projected Bridge Period 4 Mos Ending 4/30/2026	(e) Projected Bridge Period 16 Mos Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
1	Customer Billing	1,231	13	0	13	0
2	Analytics & Outreach	14	0	0	0	0
3	Credit & Assistance	0	0	680	680	1,870
4	Demand Response (C&I)	287	1,350	60	1,410	180
5	Demand Response (Res)	4,868	656	208	864	1,375
6	PowerMiDrive	1,162	0	229	229	171
7	PowerMiFleet	269	0	0	0	0
8	Total Capital	7,831	2,019	1,177	3,196	3,596

		Projected 4 Mos Ending 4/30/2025	Projected 12 Mos Ending 4/30/2026	Projected 12 Mos Ending 4/30/2027	Projected 28 Mos Ending 4/30/2027
9	Customer Billing	13	0	0	13
10	Analytics & Outreach	0	0	0	0
11	Credit & Assistance	0	680	1,870	2,550
12	Demand Response (C&I)	450	960	180	1,590
13	Demand Response (Res)	202	662	1,375	2,239
14	PowerMiDrive	0	229	171	400
15	PowerMiFleet	0	0	0	0
16	Total Capital	665	2,531	3,596	6,792

Schedule: B-5.8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Add Description
($000)

Case No.: U-21870
Exhibit No.: A-12 (JAM-1)
Schedule: B-5.8
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Witness: JAMyrom
Date: June 2025

(a)	(b)	(c)	(d)	(e)	(f)
	Historical Year	Projected Bridge Year			Projected Test Year
Line No / Description	12 Mos Ended 12/31/2024	12 Mos Ending 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1 PowerMiDrive	1,162	0	229	229	171
2 Labor	176	-	35	35	26
3 Capitalized E&S	-	-	-	0	-
4 Materials	139	-	27	27	21
5 Contractor	178	-	35	35	26
6 Non-Labor Overhead	487	-	96	96	72
7 Non-Labor Other	181	-	36	36	27
8 Contingency	-	-	-	0	-
9 PowerMiFleet	269	0	0	0	0
10 Labor	41	-	-	0	-
11 Capitalized E&S	-	-	-	0	-
12 Materials	32	-	-	0	-
13 Contractor	41	-	-	0	-
14 Non-Labor Overhead	113	-	-	0	-
15 Non-Labor Other	42	-	-	0	-
16 Contingency	-	-	-	0	-
17 Total "Electric Transportation" Capital	1,431	0	229	229	171
18 Labor	217	0	35	35	26
19 Capitalized E&S	0	0	0	0	0
20 Materials	172	0	27	27	21
21 Contractor	219	0	35	35	26
22 Non-Labor Overhead	600	0	96	96	72
23 Non-Labor Other	223	0	36	36	27
24 Contingency	0	0	0	0	0

Schedule: B-5.8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Add Description
($000)

Case No.: U-21870
Exhibit No.: A-12 (JAM-1)
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Date: June 2025

(a)		(b)	(c)	(d)	(e)
			Projected		
Line No		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
1	PowerMiDrive	0	229	171	400
2	Labor	-	35	26	61
3	Capitalized E&S	-	-	0	0
4	Materials	-	27	21	48
5	Contractor	-	35	26	61
6	Non-Labor Overhead	-	96	72	168
7	Non-Labor Other	-	36	27	62
8	Contingency	-	-	0	0
9	PowerMiFleet	0	0	0	0
10	Labor	-	-	0	0
11	Capitalized E&S	-	-	0	0
12	Materials	-	-	0	0
13	Contractor	-	-	0	0
14	Non-Labor Overhead	-	-	0	0
15	Non-Labor Other	-	-	0	0
16	Contingency	-	-	0	0
17	Total "Electric Transportation" Capital	0	229	171	400
18	Labor	0	35	26	61
19	Capitalized E&S	0	0	0	0
20	Materials	0	27	21	48
21	Contractor	0	35	26	61
22	Non-Labor Overhead	0	96	72	168
23	Non-Labor Other	0	36	27	62
24	Contingency	0	0	0	0

Schedule B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2020 through 2027
($000's)

Case No.: U-21870
Exhibit No.: A-12 (DAS-1)
Schedule: B-5.9
Page: 1 of 4
Witness: DASchmoekel
Date: June 2025

Streetlight Capital Expenditures
($000)

Line No.	(a) Description	(b) 2020 Actuals	(c) 2021 Actuals	(d) 2022 Actuals	(e) 2023 Actuals	(f) Historical 12 Months Ended 12/31/2024	(g) Projected Bridge Period 12 Mos Ended 12/31/2025	(h) Projected Bridge Period 4 Mos Ending 4/30/2026	(i) Projected Bridge Period 16 Mos Ending 4/30/2026	(j) Projected Test Year 12 Mos Ending 4/30/2027
1	New Business	$ 4,957	$ 2,320	$ 2,799	$ 2,524	$ 5,178	$ 3,630	$ 1,239	$ 4,869	$ 3,727
2	Planned Conversions - Mercury Vapor	$ 1,119							$ -	
3	Planned Conversions - Center Suspension		$ 1,023	$ 77					$ -	
4	Planned Conversions - Vicinity Conversions			$ 805	$ 412	$ 236	$ 1,000	$ 334	$ 1,334	$ 1,018
5	Demand Failures	$ 11,853	$ 12,210	$ 11,220	$ 8,769	$ 13,127	$ 15,998	$ 4,231	$ 20,229	$ 11,800
6	Grand Total	$ 17,929	$ 15,553	$ 14,901	$ 11,705	$ 18,541	$ 20,628	$ 5,804	$ 26,432	$ 16,545

Notes:
1 5-year average for demand failures and new business escalated by 2.1% for 2025
2 5-year average for demand failures and new business escalated by 2.4% for 2026
3 5-year average for demand failures and new business escalated by 0.8% for 2027

Line No.	(a) Description	(b) Projected 4 Mos Ending 4/30/2025	(c) Projected 12 Mos Ending 4/30/2026	(d) Projected 12 Mos Ending 4/30/2027	(e) Projected 26 Mos Ending 2/28/2027
7	New Business	$ 1,210	$ 3,659	$ 3,727	$ 8,597
8	Planned Conversions - Mercury Vapor				
9	Planned Conversions - Center Suspension				
10	Planned Conversions - Vicinity Conversions	$ 333	$ 1,001	$ 1,018	$ 2,352
11	Demand Failures	$ 5,333	$ 14,896	$ 11,800	$ 32,029
12	Grand Total	$ 6,876	$ 19,556	$ 16,545	$ 42,978

Schedule B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2020 through 2027

Case No.: U-21870
Exhibit No.: A-12 (DAS-1)
Schedule: B-5.9
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Date: June 2025

Streetlight Capital Expenditures
Unit Costs

Line No.	(a) Description	(b) 2020 Actuals	(c) 2021 Actuals	(d) 2022 Actuals	(e) 2023 Actuals	(f) Historical 12 Months Ended 12/31/2024	(g) Projected Bridge Period 12 Mos Ended 12/31/2025	(h) Projected Bridge Period 4 Mos Ending 4/30/2026	(i) Projected Bridge Period 16 Mos Ending 4/30/2026	(j) Projected Test Year 12 Mos Ending 4/30/2027
1	New Business Units	268	188	242	195	208	220	73	294	220
2	New Business Unit Cost	$ 18,497	$ 12,339	$ 11,565	$ 12,945	$ 24,895	$ 16,486	$ 16,882	$ 16,585	$ 16,927
3	Planned Conversions - Mercury Vapor (MV)	1,325								
4	Planned Conversions Unit Cost - MV	$ 845								
5	Planned Conversions - Center Suspension (CS)		183	19						
6	Planned Conversions Unit Cost - CS		$ 5,590	$ 4,053						
7	Planned Conversions - Vicinity Conversions (VC)			1,788	783	478	1,060	353	1,413	1,040
8	Planned Conversions Unit Cost - VC			$ 450	$ 526	$ 493	$ 505	$ 946	$ 944	$ 979
9	Demand Failures	15,310	15,775	16,407	11,974	21,205	15,021	5,007	20,028	13,800
10	Demand Failures Unit Costs	$ 774	$ 774	$ 684	$ 732	$ 619	$ 1,065	$ 845	$ 1,010	$ 855

Line No.	(a) Description	(b) Projected 4 Mos Ending 4/30/2025	(c) Projected 12 Mos Ending 4/30/2026	(d) Projected 12 Mos Ending 4/30/2027	(e) Projected 26 Mos Ending 2/28/2027
11	New Business Units	73	220	220	514
12	New Business Unit Cost	$ 16,486	$ 16,618	$ 16,927	$ 16,732
13	Planned Conversions - Mercury Vapor (MV)				
14	Planned Conversions Unit Cost - MV				
15	Planned Conversions - Center Suspension (CS)				
16	Planned Conversions Unit Cost - CS				
17	Planned Conversions - Vicinity Conversions (VC)	353	1,060	1,040	2,453
18	Planned Conversions Unit Cost - VC	943	944	979	$ 959
19	Demand Failures	5,007	15,021	13,800	33,828
20	Demand Failures Unit Costs	$ 1,065	$ 992	$ 855	$ 947

Schedule B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-12 (DAS-1)
Schedule: B-5.9
Page: 3 of 4
Witness: DASchmoekel
Date: June 2025

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Streetlight Capital Expenditures

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2024	(c) Projected Bridge Period 12 Months Ending 12/31/2025	(d) Projected Bridge Period 4 Months Ending 4/30/2026	(e) Projected Bridge Period 14 Months Ending 4/30/2026	(f) Projected Test Year 12 Mos Ending 4/30/2027
	New Business					
1	Contractor	$ 960	$ 673	$ 230	$ 902	$ 691
2	Labor	$ 1,015	$ 712	$ 243	$ 955	$ 731
3	Materials	$ 1,464	$ 1,026	$ 350	$ 1,377	$ 1,054
4	Business Expenses	$ 9	$ 6	$ 2	$ 9	$ 7
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 1,730	$ 1,213	$ 414	$ 1,627	$ 1,245
	SubTotal	$ 5,178	$ 3,630	$ 1,239	$ 4,869	$ 3,727
	Planned Conversions					
1	Contractor	$ 43	$ 181	$ 60	$ 242	$ 184
2	Labor	$ 21	$ 91	$ 30	$ 122	$ 93
3	Materials	$ 89	$ 378	$ 126	$ 505	$ 385
4	Business Expenses	$ -	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 82	$ 350	$ 117	$ 466	$ 356
	SubTotal	$ 236	$ 1,000	$ 334	$ 1,334	$ 1,018
	Demand Failures					
1	Contractor	$ 826	$ 1,007	$ 266	$ 1,273	$ 742
2	Labor	$ 1,611	$ 1,964	$ 519	$ 2,483	$ 1,449
3	Materials	$ 5,937	$ 7,235	$ 1,914	$ 9,149	$ 5,337
4	Business Expenses	$ -	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 4,753	$ 5,792	$ 1,532	$ 7,324	$ 4,272
	SubTotal	$ 13,127	$ 15,998	$ 4,231	$ 20,229	$ 11,800
	Total Streetlighting					
1	Contractor	$ 1,828	$ 1,861	$ 556	$ 2,417	$ 1,618
2	Labor	$ 2,648	$ 2,767	$ 793	$ 3,560	$ 2,272
3	Materials	$ 7,490	$ 8,640	$ 2,390	$ 11,030	$ 6,776
4	Business Expenses	$ 9	$ 6	$ 2	$ 9	$ 7
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 6,565	$ 7,354	$ 2,063	$ 9,417	$ 5,873
	Total	$ 18,541	$ 20,628	$ 5,804	$ 26,432	$ 16,545

Schedule B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-12 (DAS-1)
Schedule: B-5.9
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Witness: DASchmoekel
Date: June 2025

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Streetlight Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
			Projected		
Line No.	**Description**	**4 Mos Ending 4/30/2025**	**12 Mos Ending 4/30/2026**	**12 Mos Ending 4/30/2027**	**26 Mos Ending 2/28/2027**
	New Business				
1	Contractor	$ 224	$ 678	$ 691	$ 1,593
2	Labor	$ 237	$ 717	$ 731	$ 1,686
3	Materials	$ 342	$ 1,035	$ 1,054	$ 2,431
4	Business Expenses	$ 2	$ 6	$ 7	$ 15
5	Contingency	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 404	$ 1,222	$ 1,245	$ 2,872
	SubTotal	$ 1,210	$ 3,659	$ 3,727	$ 8,597
	Planned Conversions				
1	Contractor	$ 60	$ 181	$ 184	$ 426
2	Labor	$ 30	$ 91	$ 93	$ 214
3	Materials	$ 126	$ 379	$ 385	$ 890
4	Business Expenses	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 117	$ 350	$ 356	$ 822
	SubTotal	$ 333	$ 1,001	$ 1,018	$ 2,352
	Demand Failures				
1	Contractor	$ 336	$ 937	$ 742	$ 2,015
2	Labor	$ 655	$ 1,829	$ 1,449	$ 3,932
3	Materials	$ 2,412	$ 6,737	$ 5,337	$ 14,486
4	Business Expenses	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 1,931	$ 5,393	$ 4,272	$ 11,596
	SubTotal	$ 5,333	$ 14,896	$ 11,800	$ 32,029
	Total Streetlighting				
1	Contractor	$ 620	$ 1,797	$ 1,618	$ 4,035
2	Labor	$ 922	$ 2,637	$ 2,272	$ 5,832
3	Materials	$ 2,880	$ 8,150	$ 6,776	$ 17,806
4	Business Expenses	$ 2	$ 6	$ 7	$ 15
5	Contingency	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 2,451	$ 6,966	$ 5,873	$ 15,290
	Total	$ 6,876	$ 19,556	$ 16,545	$ 42,978

Schedule: C-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-36)
Schedule: C-1
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Sales revenues	Exhibit No.: A-13 (PDD-39)	4,758,415
2	Wholesale revenues	Exhibit No.: A-13 (PDD-39)	-
3	Other electric revenues	Exhibit No.: A-13 (PDD-39)	262,208
4	Total operating revenues	Sum Lines 1 - 3	5,020,623
5	Power supply costs	Exhibit No.: A-13 (PDD-40)	2,313,242
6	Operations and maintenance	Exhibit No.: A-13 (PDD-41)	804,952
7	Depreciation and amortization	Exhibit No.: A-13 (PDD-43)	813,088
8	Property taxes	Exhibit No.: A-13 (PDD-44)	280,500
9	General taxes	Exhibit No.: A-13 (PDD-44)	36,638
10	Other (local) taxes	Exhibit No.: A-13 (PDD-47)	1,150
11	State income taxes	Exhibit No.: A-13 (PDD-46)	33,324
12	Federal income taxes	Exhibit No.: A-13 (PDD-45)	46,009
13	Total operating expenses	Sum Lines 5 - 12	4,328,903
14	Net operating income	Line 4 - Line 13	691,720
15	AFUDC	Exhibit No.: A-13 (PDD-48)	16,026
16	Net operating income, including AFUDC	Line 14 + Line 15	707,746
	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	707,746

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 (PDD-49) and Exhibit No.: A-13 (PDD-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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-37)
Schedule: C-1.1
Page 1 of 1
Witness: PDDaly
Date: June 2025

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		4,586,002	207,553	207,255	1,879,918	916,939	884,676	244,132	35,299	1,668	43,503	41,181	953,495	24,362	977,858
	Historical Year Adjustments															
2	Weather normalization	Exhibit No.: A-15 (EMB-3), Schedule E-2	669	-	-	-	-	-	-	-	1	35	133	500	-	500
3	Purchased power administration fee revenue	WP-PDD-13	(752)	-	-	-	-	-	-	-	(1)	(39)	(149)	(562)	-	(562)
4	Surcharge Revenues	WP-PDD-14	(545,901)	-	-	-	(249,146)	(166,189)	(11,766)	74,783	(310)	(10,144)	(38,457)	(144,672)	-	(144,672)
5	Jobwork revenues	Exhibit No.: A-15 (EMB-3), Schedule E-2	-	-	1,663	-	-	-	-	-	3	87	330	1,243	-	1,243
6	Interest income on cash operating accounts	WP-PDD-15	-	-	1,622	-	-	-	-	-	3	85	322	1,212	-	1,212
7	Excess MDNR fees	WP-PDD-12	-	-	-	-	(517)	-	-	-	1	27	103	387	-	387
8	Compensation expenses	WP-PDD-16	-	-	-	-	(712)	-	-	-	1	37	141	532	-	532
9	Advertising expenses	WP-PDD-17	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Dues & donations expenses	WP-PDD-18	-	-	-	-	(674)	-	-	-	1	35	134	504	-	504
11	Jobwork expenses	Exhibit No.: A-15 (EMB-3), Schedule E-2	-	-	-	-	1,278	-	-	-	(2)	(67)	(254)	(955)	-	(955)
12	Interest expense on security deposits	WP-PDD-19	-	-	-	-	298	-	-	-	(0)	(16)	(59)	(223)	-	(223)
13	One-time Legal Consultant Expense	Exhibit No.: A-91 (MJF-2)	-	-	-	-	(3,812)	-	-	-	6	200	757	2,849	-	2,849
14	Income Tax Effect of Interest	Exhibit No.: A-3 (PDD-21)	-	-	-	-	-	-	-	-	60	1,975	7,489	(9,524)	-	(9,524)
15	Interest Synchronization Adjustment	Exhibit No.: A-3 (PDD-22)	-	-	-	-	-	-	-	-	(2)	(73)	(275)	350	-	350
16	Adjusted net operating income - historical year		4,040,018	207,553	210,541	1,879,918	663,654	718,487	232,366	110,082	1,428	35,646	11,396	805,136	24,362	829,498
	Test Year Adjustments															
17	Sales revenues		718,397	-	-	-	-	-	-	-	1,149	37,644	142,717	536,887	-	536,887
18	Wholesale revenues		-	(207,553)	-	-	-	-	-	-	(332)	(10,876)	(41,232)	(155,113)	-	(155,113)
19	Other electric revenues		-	-	51,667	-	-	-	-	-	83	2,707	10,264	38,613	-	38,613
20	Fuel and P&I expenses		-	-	-	433,324	-	-	-	-	(693)	(22,706)	(86,084)	(323,841)	-	(323,841)
21	Other operation and maintenance		-	-	-	-	141,298	-	-	-	(226)	(7,404)	(28,070)	(105,598)	-	(105,598)
22	Depreciation and amortization		-	-	-	-	-	94,601	-	-	(151)	(4,957)	(18,793)	(70,699)	-	(70,699)
23	Property taxes		-	-	-	-	-	-	48,134	-	(77)	(2,522)	(9,562)	(35,973)	-	(35,973)
24	Other general taxes		-	-	-	-	-	-	-	(73,444)	118	3,848	14,590	54,887	-	54,887
25	Other (local) income taxes		-	-	-	-	-	-	-	-	(147)	-	31	116	-	116
26	State income taxes		-	-	-	-	-	-	-	-	-	1,943	(408)	(1,535)	-	(1,535)
27	Federal income taxes		-	-	-	-	-	-	-	-	-	-	51,162	(51,162)	-	(51,162)
28	AFUDC		-	-	-	-	-	-	-	-	-	-	-	-	(8,336)	(8,336)
29	Adjusted net operating income - projected test year		4,758,415	-	262,208	2,313,242	804,952	813,088	280,500	36,638	1,150	33,324	46,009	691,720	16,026	707,746

Notes

Line 1, Col. (c) - Col. (p) Source: Exhibit No.: A-3 (PDD-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, 2027

Case No.: U-21870
Exhibit No.: A-13 (PDD-38)
Schedule: C-2
Page: 1 of 1
Witness: PDDaly
Date: June 2025

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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-39)
Schedule: C-3
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Sales revenues	Exhibit No.: A-15 (EMB-3), Schedule E-2	4,758,415
2	Wholesale revenues	N/A	-
3	Other electric revenue	Exhibit No.: A-15 (EMB-3), Schedule E-2	262,208
4	Total operating revenues	Sum Lines 1 - 3	5,020,623

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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-40)
Schedule: C-4
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Total fuel and purchased power	Exhibit No.: A-52 (EMB-6)	2,313,242

Schedule: C-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operation and Maintenance Expenses
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-41)
Schedule: C-5
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) Source	(c) Historical Year	(d) Change	(e) Projected Test Year
1	Electric Division - Electric & Common	Exhibit No.: A-122 (MPK-12)	246,620	54,373	300,994
2	Forestry	Exhibit No.: A-175 (SES-6)	110,225	76,459	186,684
3	Generation	Exhibit No.: A-43 (RTB-4)	128,438	(24,706)	103,732
4	Operations Support	Exhibit No.: A-102 (QAG-3)	14,564	(964)	13,600
5	Information Technology Operations	Exhibit No.: A-17 (SHB-1)	42,127	13,170	55,297
6	Information Technology Investments	Exhibit No.: A-19 (SHB-3)	7,835	16,955	24,789
7	Information Technology - Security Operations	Exhibit No.: A-17 (SHB-1)	9,277	2,085	11,362
8	Information Technology - Security Investments	Exhibit No.: A-19 (SHB-3)	702	811	1,513
9	Customer Interactions	Exhibit No.: A-53 (JRB-2)	20,951	2,581	23,532
10	Billing & Payment	Exhibit No.: A-53 (JRB-2)	10,176	1,251	11,427
11	Demand Response	Exhibit No.: A-95 (AMG-2)	31,240	3,391	34,630
12	Pension Plans A/B	Exhibit No.: A-97 (KKG-1)	(51,785)	6,629	(45,156)
13	Defined Company Contribution Plan	Exhibit No.: A-97 (KKG-1)	14,774	1,733	16,507
14	401(k) Employees' Savings Plan	Exhibit No.: A-97 (KKG-1)	11,396	1,335	12,731
15	Active Health Care/Life Insurance/LTD	Exhibit No.: A-97 (KKG-1)	29,089	4,296	33,385
16	Retiree Health Care and Life Insurance	Exhibit No.: A-97 (KKG-1)	(47,536)	(1,331)	(48,867)
17	Other Benefits	Exhibit No.: A-97 (KKG-1)	2,601	179	2,780
18	Pension/OPEB Volatility Mechanism Amortization	Exhibit No.: A-97 (KKG-1)	15,491	(15,590)	(99)
19	Corporate Services	Exhibit No.: A-90 (MJF-1)	37,543	(574)	36,968
20	Uncollectible Expense	Exhibit No.: A-90 (MJF-1)	18,074	2,200	20,274
21	Injuries & Damages	Exhibit No.: A-90 (MJF-1)	7,677	(2,594)	5,083
22	Incentive Compensation	Exhibit No.: A-73 (AMC-3)	2,750	(539)	2,211
23	Job Work Expense	Exhibit No.: A-15 (EMB-3), Schedule E-2	1,278	-	1,278
24	Interest expense on security deposits	WP-PDD-19	298	-	298
25	Total operation and maintenance expenses	Sum Lines 1 - 24	663,802	141,150	804,952

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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-42)
Schedule: C-5.1
Page: 1 of 1
Witness: PDDaly
Date: June 2025

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Projected Adjustments					
Line No.	Description	Source	Historical 12 Months Ended 12/31/2024	Inflation for the 12 Months Ended 12/31/2025	Inflation for the 12 Months Ended 12/31/2026	4 Months Ended 4/30/2027	Other Adjustments	Total Projected Adjustments	Projected 12 Months Ended 4/30/2027
								∑ (d) thru (g)	(c) + (h)
1	Electric Division - Electric & Common	Exhibit No.: A-128 (MPK-18)	246,620	3,971	4,633	1,581	44,188	54,373	300,994
2	Forestry	Exhibit No.: A-175 (SES-6)	110,225	-	-	-	76,459	76,459	186,684
3	Generation	Exhibit No.: A-43 (RTB-4)	128,438	2,697	3,147	1,074	(31,625)	(24,706)	103,732
4	Operations Support	Exhibit No.: A-102 (QAG-3)	14,564	26	31	10	(1,031)	(964)	13,600
5	Information Technology Operations	Exhibit No.: A-17 (SHB-1)	42,127	195	227	78	12,670	13,170	55,297
6	Information Technology Investments	Exhibit No.: A-19 (SHB-3)	7,835	-	-	-	16,955	16,955	24,789
7	Information Technology - Security Operation	Exhibit No.: A-17 (SHB-1)	9,277	81	94	32	1,878	2,085	11,362
8	Information Technology - Security Investmer	Exhibit No.: A-19 (SHB-3)	702	-	-	-	811	811	1,513
9	Customer Interactions	Exhibit No.: A-53 (JRB-2)	20,951	440	513	175	1,452	2,581	23,532
10	Billing & Payment	Exhibit No.: A-53 (JRB-2)	10,176	214	249	85	703	1,251	11,427
11	Demand Response	Exhibit No.: A-95 (AMG-2)	31,240	656	765	261	1,708	3,391	34,630
12	Pension Plans A/B	Exhibit No.: A-97 (KKG-1)	(51,785)	(1,087)	(1,269)	(433)	9,419	6,629	(45,156)
13	Defined Company Contribution Plan	Exhibit No.: A-97 (KKG-1)	14,774	310	362	124	937	1,733	16,507
14	401(k) Employees' Savings Plan	Exhibit No.: A-97 (KKG-1)	11,396	239	279	95	721	1,335	12,731
15	Active Health Care/Life Insurance/LTD	Exhibit No.: A-97 (KKG-1)	29,089	611	713	243	2,729	4,296	33,385
16	Retiree Health Care and Life Insurance	Exhibit No.: A-97 (KKG-1)	(47,536)	(998)	(1,165)	(398)	1,230	(1,331)	(48,867)
17	Other Benefits	Exhibit No.: A-97 (KKG-1)	2,601	55	64	22	39	179	2,780
18	Pension/OPEB Volatility Mechanism Amortiz	Exhibit No.: A-97 (KKG-1)	15,491	325	380	130	(16,424)	(15,590)	(99)
19	Corporate Services	Exhibit No.: A-91 (MJF-2)	37,543	788	920	314	(2,597)	(575)	36,968
20	Uncollectible Expense	N/A	18,074	-	-	-	2,200	2,200	20,274
21	Injuries & Damages	N/A	7,677	-	-	-	(2,594)	(2,594)	5,083
22	Incentive Compensation	Exhibit No.: A-73 (AMC-3)	2,750	44	51	18	(653)	(539)	2,211
23	Job Work Expense	Exhibit No.: A-15 (EMB-3), Schedule E-2	1,278	-	-	-	-	-	1,278
24	Interest expense on security deposits	WP-PDD-19	298	-	-	-	-	-	298
25	Projected inflation of other O&M expenses	Sum Lines 1 - 24	663,802	8,566	9,996	3,412	119,176	141,150	804,952

Schedule: C-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation and Amortization Expenses
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-43)
Schedule: C-6
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Distribution	WP-PDD-24 Col. (d), Line 60	422,195
2	Production (Hydro)	WP-PDD-24 Col. (d), Line 61	46,435
3	Production (Hydro Ludington)	WP-PDD-24 Col. (d), Line 62	17,519
4	Production (Steam)	WP-PDD-24 Col. (d), Line 63	18,211
5	Production (Solar)	WP-PDD-24 Col. (d), Line 64	-
6	Production (Other)	WP-PDD-24 Col. (d), Line 65	46,150
7	Intangibles	WP-PDD-24 Col. (d), Line 66	52,988
8	E-GP Structures	WP-PDD-24 Col. (d), Line 67	4,803
9	E-GP Computers	WP-PDD-24 Col. (d), Line 68	2,459
10	E-GP Transportation	WP-PDD-24 Col. (d), Line 69	-
11	E-GP Other	WP-PDD-24 Col. (d), Line 70	4,104
12	C-GP Structures	WP-PDD-24 Col. (d), Line 71	2,719
13	C-GP Computers	WP-PDD-24 Col. (d), Line 72	10,341
14	C-GP Transportation	WP-PDD-24 Col. (d), Line 73	-
15	C-GP Other	WP-PDD-24 Col. (d), Line 74	6,094
16	Production Acq Adjustment	WP-PDD-24 Col. (d), Line 75	20,285
17	PowerMiDrive	Exhibit No.: A-75 (PDD-51)	3,738
18	PowerMiFleet	Exhibit No.: A-75 (PDD-51)	1,782
19	Karn Plant Retention and Separation Costs	Exhibit No.: A-76 (PDD-52)	334
20	Campbell Plant Retention and Separation Costs	Exhibit No.: A-76 (PDD-52)	8,480
21	Campbell Net Book Value Amortization	Exhibit No.: A-77 (PDD-53)	125,559
22	Karn 1-2 Decommissioning Costs Amortization	Exhibit No.: A-78 (PDD-54)	8,543
23	Campbell Decommissioning Costs Amortization	Exhibit No.: A-78 (PDD-54)	2,198
24	Karn 1-2 and Classic 7 Ash Disposal Amortization	Exhibit No.: A-79 (PDD-55)	8,150
25	Total depreciation and amortization expenses	Sum Lines 1 - 24	813,088

Schedule: C-7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
General Taxes
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-44)
Schedule: C-7
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Total Amount
1	Real and personal property taxes	Exhibit No.: A-181 (BJV-1)	280,500
	Projected payroll taxes		
2	Total payroll taxes - historical year	Exhibit No.: A-3 (PDD-16)	24,047
3	Inflation factor 2025	WP-PDD-37	102.1%
4	Inflation factor 2026	WP-PDD-37	102.4%
5	Inflation factor 2027	WP-PDD-37	100.8%
6	Total payroll taxes - projected year	Line 2 * Line 3 * Line 4 * Line 5	25,343
	Projected other general taxes		
7	State MPSC assessment - historical year	Exhibit No.: A-3 (PDD-16)	11,104
8	Total operating revenues - historical year	Exhibit No.: A-3 (PDD-11)	5,000,811
9	Average State MPSC assessment rate	Line 7 / Line 8	0.22%
10	Total operating revenues - projected year	Exhibit No.: A-13 (PDD-39)	5,020,623
11	Average State MPSC assessment rate	Line 9	0.22%
12	Projected State MPSC assessment	Line 10 * Line 11	11,148
13	Incremental change in State MPSC assessment	Line 12 - Line 7	44
14	Other general taxes - historical year	Exhibit No.: A-3 (PDD-16)	11,252
15	Total other general taxes - projected year	Line 13 + Line 14	11,296
16	Total general taxes	Line 1 + Line 6 + Line 15	317,138

Schedule: C-8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Federal Income Taxes
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-45)
Schedule: C-8
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) Source	(c) Amount
1	Operating revenues	Exhibit No.: A-13 (PDD-39)	5,020,623
2	Power supply costs	Exhibit No.: A-13 (PDD-40)	(2,313,242)
3	Other O&M expenses	Exhibit No.: A-13 (PDD-41)	(804,952)
4	Depreciation and amortization expenses	Exhibit No.: A-13 (PDD-43)	(813,088)
5	General taxes	Exhibit No.: A-13 (PDD-44)	(317,138)
6	State income taxes	Exhibit No.: A-13 (PDD-46), Line 20 * -1	(33,324)
7	Other (local) income taxes	Exhibit No.: A-13 (PDD-47), Line 18 * -1	(1,150)
8	Net operating income	Sum Lines 1 - 7	737,729
9	Allowable interest expense	Exhibit No.: A-13 (PDD-49)	(293,225)
10	Allowable JDITC interest expense	Exhibit No.: A-13 (PDD-50)	(1,588)
11	Pre-tax operating income	Sum Lines 8 - 10	442,916
	Permanent Differences		
12	Meals and entertainment	Tax Department	901
13	Non-deductible parking	Tax Department	103
14	Total permanent differences	Sum Lines 12 - 13	1,004
	Temporary Differences		
15	Book depreciation	Exhibit No.: A-13 (PDD-43)	813,088
16	Tax depreciation	Tax Department	(744,776)
17	263A - mixed service costs deduction	Tax Department	(29,232)
18	Tax repairs	Tax Department	(217,000)
19	Contributions in aid of construction/Grants	Tax Department	9,056
20	Cost of removal	Tax Department	(144,663)
21	Gain/loss on ACRS/MACRS dispositions	Tax Department	(19,356)
22	Software expense	Tax Department	-
23	Tax interest during construction	Tax Department	42,210
24	Bad debt allowance	Tax Department	-
25	OPEB - book expense	Exhibit No.: A-13 (PDD-41), Line 16	(48,867)
26	OPEB - payments	Tax Department	-
27	Other revenue reserves	Tax Department	-
28	Pension book expense	Exhibit No.: A-13 (PDD-41), Line 12	(45,156)
29	Pension - payments	Tax Department	-
30	Securitization Amortization	Tax Department	115,733
31	Premium, discount & debt expense amortization	Tax Department	2,528
32	Real and personal property taxes	Tax Department	(32,306)
33	Renewable energy reserve	Tax Department	(90,712)
34	Deferred state income taxes	Tax Department	31,288
35	Deferred city income taxes	Tax Department	1,011
36	Total temporary differences	Sum Lines 15 - 33	(357,154)
37	Federal taxable income	Line 11 + Line 14 + Line 36	86,765
	Calculation of Current Federal Income Tax Expenses		
38	Current federal income taxes	Line 37 * 21.00% Federal Income Tax Rate	18,221
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	16,929
	Calculation of Deferred Federal Income Tax Expenses		
42	Deferred federal income taxes	(Line 36 * 21.00% Federal Income Tax Rate) * -1	75,002
43	FAS 109	Tax Department	(110)
44	Investment tax credit amortization	Tax Department	(5,599)
45	TCJA amortization - ARAM	Tax Department	(28,379)
46	TCJA amortization - non-ARAM	Tax Department	(4,148)
47	TCJA Tracker	Tax Department	(7,907)
48	Repealed Medicare subsidy benefit	Tax Department	221
49	Total deferred federal income tax expenses	Sum Lines 42 - 48	29,080
50	Total federal income taxes	Line 41 + Line 49	46,009

Schedule: C-9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
State Income Taxes
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-46)
Schedule: C-9
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) Source	(c) Amount
1	Operating revenues	Exhibit No.: A-13 (PDD-39)	5,020,623
2	Power supply costs	Exhibit No.: A-13 (PDD-40)	(2,313,242)
3	Other O&M expenses	Exhibit No.: A-13 (PDD-41)	(804,952)
4	Depreciation and amortization expenses	Exhibit No.: A-13 (PDD-43)	(813,088)
5	General taxes	Exhibit No.: A-13 (PDD-44)	(317,138)
6	Net operating income	Sum Lines 1 - 5	772,203
7	Interest expense	Exhibit No.: A-13 (PDD-49)	(293,225)
8	Interest synchronization	Exhibit No.: A-13 (PDD-50)	(1,588)
9	Pre-tax operating income	Sum Lines 6 - 8	477,390
10	Total permanent differences	Exhibit No.: A-13 (PDD-45)	1,004
11	Schedule M temp diff, excluding DSIT and DCIT	Exhibit No.: A-13 (PDD-45)	(389,453)
12	Depreciation/gain-loss adjustment	Tax Department	(50,090)
13	State taxable income	Sum Lines 9 - 12	38,850
14	Current state income taxes	Line 13 * 5.24% State Income Tax Rate	2,036
	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	23,032
16	FAS 109 - AFUDC-equity flow-through reversal	Tax Department	963
17	Deferred - amortization of Medicare Subsidy benefit - state	Tax Department	38
18	Deferred - amortization of state income tax transition reg asset	Tax Department	7,255
19	Deferred state income taxes	Sum Lines 15 - 18	31,288
20	Total state income taxes	Line 14 + Line 19	33,324

Schedule: C-10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Other (or Local) Taxes
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-47)
Schedule: C-10
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Operating revenues	Exhibit No.: A-13 (PDD-39)	5,020,623
2	Power supply costs	Exhibit No.: A-13 (PDD-40)	(2,313,242)
3	Other O&M expenses	Exhibit No.: A-13 (PDD-41)	(804,952)
4	Depreciation and amortization expenses	Exhibit No.: A-13 (PDD-43)	(813,088)
5	General taxes	Exhibit No.: A-13 (PDD-44)	(317,138)
6	State income taxes	Exhibit No.: A-13 (PDD-46)	(33,324)
7	Net operating income	Sum Lines 1 - 6	738,879
8	Interest expense	Exhibit No.: A-13 (PDD-49)	(293,225)
9	Interest synchronization	Exhibit No.: A-13 (PDD-50)	(1,588)
10	Pre-tax operating income	Sum Lines 7 - 9	444,066
11	Total permanent differences	Exhibit No.: A-13 (PDD-45)	1,004
12	Schedule M temp diff, excluding DCIT	Exhibit No.: A-13 (PDD-45)	(358,165)
13	Other (local) taxable income	Sum Lines 10 - 12	86,905
14	Current other (local) income taxes	Line 13 * 0.16% Other (Local) Income Tax Rate	139
	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	573
16	Deferred - amortization of reg asset	Exhibit No.: A-13 (PDD-45)	438
17	Total deferred other (local) income taxes	Line 15 + Line 16	1,011
18	Total other (local) income taxes	Line 14 + Line 17	1,150

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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-48)
Schedule: C-11
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No	(a) Description	(b) Source	(c) Amount
1	Total allowance for funds used during construction	WP-PDD-25	16,026

Schedule: C-12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Income Tax Effect of Interest
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-49)
Schedule: C-12
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-12 (PDD-31)	15,367,518
2	Weighted cost of debt {1}	Exhibit No.: A-14 (MRB-1), Schedule D-1	0.0191
3	Allowable interest expense	Line 1 * Line 2	293,225
4	Pro forma interest expense - historical year	Exhibit No.: A-3 (PDD-21)	249,872
5	Increase/ (decrease) in allowable interest deduction	Line 3 - Line 4	43,353
6	Impact on taxable income	Line 5 * -1	(43,353)
7	Impact on state and local income taxes	Line 6 * 5.40% State and Local Income Tax Rate	(2,341)
8	Impact on federal taxable income	Line 6 - Line 7	(41,012)
9	Impact on federal income taxes	Line 8 * 21.00% Federal Income Tax Rate	(8,613)
10	Total impact on net operating income	(Line 7 + Line 9) * -1	10,954

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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-50)
Schedule: C-13
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-12 (PDD-31)	15,367,518
2	JDITC debt-related portion of the capital structure	Exhibit No.: A-14 (MRB-1), Schedule D-1	0.0023
3	Portion of rate base funded by JDITC	Line 1 * Line 2	34,987
4	Cost of JDITC - debt portion	Exhibit No.: A-14 (MRB-1), Schedule D-1	0.0454
5	Allowable JDITC interest expense	Line 3 * Line 4	1,588
6	Allowable JDITC interest expense - historical year	Exhibit No.: A-3 (PDD-22)	1,385
7	Increase/ (decrease) in allowable JDITC interest expense	Line 5 - Line 6	202
8	Impact on taxable income	Line 7 * -1	(202)
9	Impact on state and local income taxes	Line 8 * 5.40% State and Local Income Tax Rate	(11)
10	Impact on federal taxable income	Line 8 - Line 9	(191)
11	Impact on federal income taxes	Line 10 * 21.00% Federal Income Tax Rate	(40)
12	Total impact on net operating income	(Line 9 + Line 11) * -1	51

Schedule D-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Overall Rate of Return Summary
for the Projected Year Ending April 30, 2027

Case No.: U-21870
Exhibit No.: A-14 (MRB-1)
Schedule: D-1
Page: 1 of 1
Witness: MRBleckman
Date: June 2025

Line No.	(a) Description	(b) Amount ($000,000) (1)	(c) Capital Structure Percent Permanent Capital (2)	(d) Percent of Total Capital	(e) Cost Rate %	(f) Permanent Capital (7)	(g) Weighted Cost Total Cost % (8)	(h) Conversion Factor	(i) Pre-Tax Return (9)
1									
2	Long-Term Debt	$ 13,465	49.11%	41.55%	4.54% (3)	2.23%	1.89%	1.0000	1.89%
3									
4	Preferred Stock	37	0.14%	0.12%	4.50% (4)	0.01%	0.01%	1.3381	0.01%
5									
6	Common Shareholder's Equity	13,916	50.75%	42.94%	10.25% (5)	5.20%	4.40%	1.3381	5.89%
7									
8	Total Permanent Capital	$ 27,418	100.00%						
9									
10	Short-Term Debt	148		0.46%	4.92% (6)		0.02%	1.0000	0.02%
11									
12	Deferred Income Taxes	4,692		14.48%	0.00%		0.00%	1.0000	0.00%
13									
14	Investment Tax Credit								
15	Long-Term Debt	74		0.23%	4.54%		0.01%	1.0000	0.01%
16	Preferred Stock	0		0.00%	4.50%		0.00%	1.3381	0.00%
17	Common Equity	74		0.23%	10.25%		0.02%	1.3381	0.03%
18									
19	Total	$ 32,407		100.00%			6.35%		7.85%

(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, 2027

Case No.: U-21870
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
Page: 1 of 4
Witness: MRBleckman
Date: June 2025

Line No.	(a) Description	(b) Historical Capital Structure 13-Month Avg. For Yr. Ended December 31, 2024 Amount Outstanding (000,000)	(c) % of Permanent Capital	(d) % of Total Capital	(e) Balances as of Dec. 31, 2024 (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	$ 11,136	50.46%	42.09%	$ 11,392	$ 2,073	$ 13,465	49.11%	41.55%
3									
4	Preferred Stock	37	0.17%	0.14%	37	-	37	0.14%	0.12%
5									
6	Common Equity	10,894	49.37%	41.17%	11,405	2,511	13,916	50.75%	42.94%
7									
8	Total Permanent Capital	$ 22,067	100.00%		$ 22,834	$ 4,584	$ 27,418	100.00%	
9									
10	Short-Term Debt	62		0.24%	116	32	148		0.46%
11									
12	Deferred Income Taxes	4,206		15.90%	4,289	404	4,692		14.48%
13									
14	Investment Tax Credit								
15	Long-Term Debt	63		0.24%	61	13	74		0.23%
16	Preferred Stock	0		0.00%	0	0	0		0.00%
17	Common Equity	61		0.23%	61	13	74		0.23%
18									
19	Total Investment Tax Credit	124		0.47%	122	26	148		0.46%
20									
21	Total Capitalization	$ 26,460		100.00%	$ 27,361	$ 5,046	$ 32,407		100.00%

Sources and Support, by Column:

(b) Consumers Energy General Ledger 13-month average balances as of December 31, 2024.
(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, 2024.
(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, 2027
(in millions)

Case No.: U-21870
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
Page: 2 of 4
Witness: MRBleckman
Date: June 2025

Line No.	(a) Long-Term Debt	(b) Actual Jan-24	(c) Actual Feb-24	(d) Actual Mar-24	(e) Actual Apr-24	(f) Actual May-24	(g) Actual Jun-24	(h) Actual Jul-24	(i) Actual Aug-24	(j) Actual Sep-24	(k) Actual Oct-24	(l) Actual Nov-24	(m) Actual Dec-24
1													
2	Beginning Balance	$ 10,507	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,807	$ 11,557	$ 11,557	$ 11,557
3	Add: Issuances	600	-	-	-	-	-	-	700	-	-	-	-
4	Less: Retirements	-	-	-	-	-	-	-	-	(250)	-	-	(52)
5	Subtotal	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,807	$ 11,557	$ 11,557	$ 11,557	$ 11,505
6													
7	Less: Unamortized Fees	(115)	(114)	(113)	(113)	(112)	(112)	(111)	(116)	(116)	(115)	(114)	(113)
8													
9	Ending Balance	$ 10,992	$ 10,993	$ 10,994	$ 10,994	$ 10,995	$ 10,995	$ 10,996	$ 11,691	$ 11,441	$ 11,442	$ 11,443	$ 11,392
10													
11													
12													
13	Long-Term Debt	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
14													
15	Beginning Balance	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 11,980	$ 11,980	$ 11,980	$ 12,630	$ 12,630	$ 12,630	$ 12,630
16	Add: Issuances	-	-	-	-	475	-	-	650	-	-	-	-
17	Less: Retirements	-	-	-	-	-	-	-	-	-	-	-	-
18	Subtotal	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 11,980	$ 11,980	$ 11,980	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 12,630
19													
20	Less: Unamortized Fees	(113)	(112)	(111)	(110)	(114)	(114)	(113)	(118)	(117)	(116)	(115)	(114)
21													
22	Ending Balance	$ 11,392	$ 11,393	$ 11,394	$ 11,395	$ 11,866	$ 11,866	$ 11,867	$ 12,512	$ 12,513	$ 12,514	$ 12,515	$ 12,516
23													
24													
25													
26	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
27													
28	Beginning Balance	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 13,115	$ 13,115	$ 13,115	$ 13,840	$ 13,840	$ 13,840	$ 13,840
29	Add: Issuances	-	-	-	-	600	-	-	725	-	-	-	-
30	Less: Retirements	-	-	-	-	(115)	-	-	-	-	-	-	-
31	Subtotal	$ 12,630	$ 12,630	$ 12,630	$ 12,630	$ 13,115	$ 13,115	$ 13,115	$ 13,840	$ 13,840	$ 13,840	$ 13,840	$ 13,840
32													
33	Less: Unamortized Fees	(113)	(112)	(111)	(110)	(115)	(114)	(113)	(119)	(118)	(117)	(116)	(115)
34													
35	Ending Balance	$ 12,517	$ 12,518	$ 12,519	$ 12,520	$ 13,000	$ 13,001	$ 13,002	$ 13,721	$ 13,722	$ 13,723	$ 13,724	$ 13,725
36													
37													
38													
39	Long-Term Debt	Jan-27	Feb-27	Mar-27	Apr-27								
40													
41	Beginning Balance	$ 13,840	$ 13,840	$ 13,840	$ 13,840								
42	Add: Issuances	-	-	-	-								
43	Less: Retirements	-	-	-	-								
44	Subtotal	$ 13,840	$ 13,840	$ 13,840	$ 13,840								
45													
46	Less: Unamortized Fees	(114)	(113)	(112)	(111)								
47													
48	Ending Balance	$ 13,726	$ 13,727	$ 13,728	$ 13,729								
49													
50	**Test Year 13-Month Average:**												
51	Subtotal				$ 13,580								
52	Less: Unamortized Fees				(114)								
53	Ending Balance				**$ 13,465**								

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development - Projected Common Equity Balance
for the Projected Year Ending April 30, 2027
(in millions)

Case No.: U-21870
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
Page: 3 of 4
Witness: MRBleckman
Date: June 2025

Line No.	(a) Common Equity	(b) Actual Jan-24	(c) Actual Feb-24	(d) Actual Mar-24	(e) Actual Apr-24	(f) Actual May-24	(g) Actual Jun-24	(h) Actual Jul-24	(i) Actual Aug-24	(j) Actual Sep-24	(k) Actual Oct-24	(l) Actual Nov-24	(m) Actual Dec-24
1													
2	Beginning Balance	$10,779	$10,898	$10,712	$10,788	$10,790	$10,848	$10,872	$10,796	$10,885	$10,960	$10,759	$11,135
3	Ret. Earnings	119	(186)	76	2	58	24	(76)	89	75	(201)	76	155
4	Equity Infusion	-	-	-	-	-	-	-	-	-	-	300	115
5	Ending Balance	$ 10,898	$ 10,712	$ 10,788	$ 10,790	$ 10,848	$ 10,872	$ 10,796	$ 10,885	$ 10,960	$ 10,759	$ 11,135	$ 11,405
6													
7													
8													
9	Common Equity	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
10													
11	Beginning Balance	$11,405	$11,421	$11,588	$11,605	$11,622	$11,914	$12,355	$12,372	$12,389	$12,406	$12,463	$12,479
12	Ret. Earnings	17	17	17	17	17	17	17	17	17	17	17	17
13	Equity Infusion	-	150	-	-	275	425	-	-	-	40	-	-
14	Ending Balance	$ 11,421	$ 11,588	$ 11,605	$ 11,622	$ 11,914	$ 12,355	$ 12,372	$ 12,389	$ 12,406	$ 12,463	$ 12,479	$ 12,496
15													
16													
17													
18	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
19													
20	Beginning Balance	$12,496	$12,513	$13,055	$13,071	$13,088	$13,105	$13,797	$13,814	$13,830	$13,847	$13,864	$13,881
21	Ret. Earnings	17	17	17	17	17	17	17	17	17	17	17	17
22	Equity Infusion	-	525	-	-	-	675	-	-	-	-	-	-
23	Ending Balance	$ 12,513	$ 13,055	$ 13,071	$ 13,088	$ 13,105	$ 13,797	$ 13,814	$ 13,830	$ 13,847	$ 13,864	$ 13,881	$ 13,898
24													
25													
26													
27	Common Equity	Jan-27	Feb-27	Mar-27	Apr-27								
28													
29	Beginning Balance	$13,898	$13,914	$14,606	$14,623								
30	Ret. Earnings	17	17	17	17								
31	Equity Infusion	-	675	-	-								
32	Ending Balance	$ 13,914	$ 14,606	$ 14,623	$ 14,640								
33													
34													
35	**Test Year 13-Month Average**				**$ 13,916**								

(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Test Year Impact of Retained Earnings			Test Year Impact of Equity Infusions		
	2025	**2026**	**2027**	**2025**	**2026**	**2027**
Jan	$ 17	$ 218	$ 420	$ -	$ 890	$ 2,090
Feb	$ 34	$ 235	$ 436	$ 150	$ 1,415	$ 2,765
Mar	$ 50	$ 252	$ 453	$ 150	$ 1,415	$ 2,765
Apr	$ 67	$ 269	$ 470	$ 150	$ 1,415	$ 2,765
May	$ 84	$ 285		$ 425	$ 1,415	
Jun	$ 101	$ 302		$ 850	$ 2,090	
Jul	$ 117	$ 319		$ 850	$ 2,090	
Aug	$ 134	$ 336		$ 850	$ 2,090	
Sep	$ 151	$ 352		$ 850	$ 2,090	
Oct	$ 168	$ 369		$ 890	$ 2,090	
Nov	$ 185	$ 386		$ 890	$ 2,090	
Dec	$ 201	$ 403		$ 890	$ 2,090	
13-Month Avg.			$ 369			$ 2,142

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, 2027
(in millions)

Case No.: U-21870
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
Page: 4 of 4
Witness: MRBleckman
Date: June 2025

Deferred Income Tax Ending Balance

Line No.	(a) Actual Jan-24	(b) Actual Feb-24	(c) Actual Mar-24	(d) Actual Apr-24	(e) Actual May-24	(f) Actual Jun-24	(g) Actual Jul-24	(h) Actual Aug-24	(i) Actual Sep-24	(j) Actual Oct-24	(k) Actual Nov-24	(l) Actual Dec-24
1	$ 4,116	$ 4,129	$ 4,142	$ 4,155	$ 4,169	$ 4,182	$ 4,195	$ 4,208	$ 4,221	$ 4,234	$ 4,247	$ 4,289
2												
3												
4												
5	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
6	$ 4,307	$ 4,326	$ 4,344	$ 4,363	$ 4,382	$ 4,400	$ 4,419	$ 4,437	$ 4,456	$ 4,474	$ 4,493	$ 4,512
7												
8												
9												
10	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
11	$ 4,530	$ 4,548	$ 4,566	$ 4,584	$ 4,603	$ 4,621	$ 4,639	$ 4,657	$ 4,675	$ 4,694	$ 4,712	$ 4,730
12												
13												
14												
15	Jan-27	Feb-27	Mar-27	Apr-27								
16	$ 4,747	$ 4,764	$ 4,780	$ 4,797								
17												
18												
19	**Test Year 13-Month Avg**			**$ 4,692**								

Schedule D-1b

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Development of Capital Structure
for the Projected Year Ending April 30, 2027

Case No.: U-21870
Exhibit No.: A-14 (MRB-3)
Schedule: D-1b
Page: 1 of 1
Witness: MRBleckman
Date: June 2025

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, 2027

Case No.: U-21870
Exhibit No.: A-14 (MRB-4)
Schedule: D-2
Page: 1 of 1
Witness: MRBleckman
Date: June 2025

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%	35,500	1,220
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%	100,000	3,701
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	3.300%	4	75,649	100.00%	1.000%	756.49	0.99%	751.55	0.00	98.007%	3.3828%	75,649	2,559
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	3.300%	4	134,349	100.00%	1.000%	1,343.49	0.29%	390.52	0.00	98.709%	3.3533%	134,349	4,505
31	Floating Rate FMB	07-Oct-20	07-Oct-70	3.300%	4	126,497	100.00%	1.000%	1,264.97	0.25%	315.63	0.00	98.750%	3.3516%	126,497	4,240
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%	425,000	20,689
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	5.24% (Private Placement)	15-May-23	15-May-26	5.240%	2	115,000	100.00%	0.875%	1,006.25	0.20%	230.00	0.00	98.925%	5.6345%	8,846	498
38	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
39	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
40	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
41	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
42	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
43	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
44	New Debt Issue #1	01-May-25	01-May-55	6.240%	2	475,000	100.00%	0.875%	4,156.25	0.20%	950.00	0.00	98.925%	6.3204%	475,000	30,022
45	New Debt Issue #2	01-Aug-25	01-Aug-55	6.240%	2	650,000	100.00%	0.875%	5,687.50	0.20%	1,300.00	0.00	98.925%	6.3204%	650,000	41,082
46	New Debt Issue #3	01-May-26	02-May-56	6.270%	2	600,000	100.00%	0.875%	5,250.00	0.20%	1,200.00	0.00	98.925%	6.3506%	553,846	35,173
47	New Debt Issue #4	01-Aug-26	01-Aug-56	6.270%	2	725,000	100.00%	0.875%	6,343.75	0.20%	1,450.00	0.00	98.925%	6.3506%	501,923	31,875
48	Total Mortgage Bonds														$ 13,469,610	$ 603,666
49																
50	**Other Long-Term Debt**															
51	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
52	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
53															$ 110,000	$ 2,920
54																
55																
56	Total Long-Term Debt														$ 13,579,610	$ 606,586
57																
58	Amortization of Losses on Reacquired Debt with Refunding (including Call Premiums)															4,342
59																
60	Total Long-Term Debt Before Unamortized Expense and Premium													4.50%	$ 13,579,610	$ 610,928
61																
62	Unamortized Debt Discount, Expense and Premium														(114,385)	
63																
64	Total Long-Term Debt Balance														$ 13,465,226	
65																
66	Annual Cost													4.54%		
67																

Ties to 13-Month Average in Exhibit A-14 (MRB-2), Schedule D-1a, pg. 2

68 **Calculations:**
69 Column (i) = Yield formula based on inputs from column (b),column (c), column (d), column (d1), and column (h) calculated on an annualized basis.
70 Column (j) = Represents the average amount of debt outstanding for the test year.
71 Column (k) = column (i)*column (j).
72 Lines 27, 30, and 31 Coupon Rate = Projected SOFR Rate of 3.34% minus 0.04%.
73 Lines 37, 46, and 47 - As this is a partial year debt outstanding, pro-rata balance and pro-rata interest expense are used which would result
74 in the same cost rate as an annual analysis, but provides a more accurate average debt balance for the Test Year. This would make
75 the Total Debt balance line 64 tie to the debt balance shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.
76 Line 58 - Amortization of losses on reacquired debt projected for the test year ending April 30, 2027.
77
78 Projected SOFR Rate — Test Year Avg.
79
80 Bloomberg (Apr. 14, 2025) 3.34%

Projected New Debt Issue Interest Rates	New Debt #1 May 2025	New Debt #2 Aug. 2025	New Debt #3 May 2026	New Debt #4 Aug. 2026
Projected 30-Yr Treasury Rate (Bloomberg)	4.86%	4.86%	4.89%	4.89%
Add: Historical 30-Year Bond Spread	1.38%	1.38%	1.38%	1.38%
	6.24%	**6.24%**	**6.27%**	**6.27%**

Schedule D-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Short-Term Debt
for the Projected Year Ending April 30, 2027
(in millions)

Case No.: U-21870
Exhibit No.: A-14 (MRB-5)
Schedule: D-3
Page: 1 of 2
Witness: MRBleckman
Date: June 2025

Line No.		(a) **Average Borrowings**	(b) **Cost of Borrowings**	(c) **Cost Rate**
1	Short-Term Debt	$ 148.3	$ 7.3	4.92%

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, 2027
(in millions)

Case No.: U-21870
Exhibit No.: A-14 (MRB-5)
Schedule: D-3
Page: 2 of 2
Witness: MRBleckman
Date: June 2025

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	Jun. 2018	Dec. 2027	$ 1,100.0	$ -	$ 28.1	$ 1,071.9	$ 0.4
2	2. Commercial Paper Facility	Sep. 2014	N/A	$ 500.0	$ 148.3	$ -	$ -	$ -
3	3. Scotiabank Revolver	Nov. 2018	Nov. 2025	$ 250.0	$ -	$ 58.3	$ 191.7	$ 0.3

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	3.34%	0.850%	4.19%	$ -	$ -
2. Commercial Paper Facility	3.34%	0.000%	3.34%	148.3	5.0
3. Scotiabank Revolver	3.34%	0.800%	4.14%	-	-
					$ 5.0

(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	0.850%	$ 28.1	$ 0.2
2. Commercial Paper Facility	N/A	N/A	-	-
3. Scotiabank Revolver	MISO Margin & Other	0.800%	58.3	0.5
				$ 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	0.070%	$ 1,071.9	$ 0.8
2. Commercial Paper Facility	N/A	-	-
3. Scotiabank Revolver	0.075%	$ 191.7	$ 0.1
			$ 0.9

(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. Scotiabank Revolver	0.3
	$ 0.7

Total Cost of Short-Term Debt **$ 7.3**

[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, 2027

Case No.: U-21870
Exhibit No.: A-14 (MRB-6)
Schedule: D-4
Page: 1 of 1
Witness: MRBleckman
Date: June 2025

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).

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	8.92%	10.24%	11.18%
90-Day Avg. Stock Price	9.06%	10.38%	11.32%
180-Day Avg. Stock Price	9.16%	10.47%	11.42%
Average	9.05%	10.36%	11.31%
Median Results:			
30-Day Avg. Stock Price	9.47%	10.07%	10.77%
90-Day Avg. Stock Price	9.62%	10.27%	10.88%
180-Day Avg. Stock Price	9.79%	10.43%	11.01%
Average	9.63%	10.26%	10.89%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	12.18%	12.18%	12.17%
Current Bloomberg Beta	10.85%	10.83%	10.78%
Long-term Avg. *Value Line* Beta	10.85%	10.83%	10.79%
ECAPM:			
Current *Value Line* Beta	12.28%	12.28%	12.27%
Current Bloomberg Beta	11.28%	11.26%	11.23%
Long-term Avg. *Value Line* Beta	11.29%	11.27%	11.24%
Bond Yield Risk Premium	10.67%	10.62%	10.49%

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 > 40%	[6] Regulated Elec. Operating Income / Total Operating Income > 60%	[7] Announced Merger
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	75.72%	88.17%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	72.83%	84.73%	No
American Electric Power Company, Inc.	AEP	Yes	BBB+	Yes	Yes	52.31%	99.95%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	60.28%	73.88%	No
Dominion Resources, Inc.	D	Yes	BBB+	Yes	Yes	78.55%	95.13%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	84.17%	71.10%	No
Duke Energy Corporation	DUK	Yes	BBB+	Yes	Yes	80.86%	90.37%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	71.73%	97.99%	No
Evergy, Inc.	EVRG	Yes	BBB+	Yes	Yes	62.48%	100.00%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	62.48%	99.98%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	96.37%	88.15%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	57.78%	85.59%	No
OGE Energy Corporation	OGE	Yes	A-	Yes	Yes	45.23%	100.00%	No
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Yes	Yes	72.64%	100.00%	No
TXNM Energy	TXNM	Yes	BBB	Yes	Yes	50.48%	100.00%	No
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	54.70%	100.00%	No
PPL Corporation	PPL	Yes	A-	Yes	Yes	41.64%	94.24%	No
Southern Company	SO	Yes	A-	Yes	Yes	76.55%	73.40%	No
Xcel Energy Inc.	XEL	Yes	BBB+	Yes	Yes	58.13%	85.90%	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 2023, 2022, and 2021
[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	$2.03	$63.18	3.21%	3.32%	6.00%	6.81%	6.70%	6.50%	9.31%	9.82%	10.14%
Ameren Corporation	AEE	$2.84	$98.76	2.88%	2.97%	6.50%	6.88%	6.70%	6.69%	9.47%	9.66%	9.85%
American Electric Power Company, Inc.	AEP	$3.72	$105.20	3.54%	3.65%	6.50%	6.69%	6.30%	6.50%	9.95%	10.15%	10.35%
Avista Corporation	AVA	$1.96	$39.32	4.98%	5.13%	5.50%	5.88%	6.10%	5.83%	10.62%	10.96%	11.24%
Dominion Resources, Inc.	D	$2.67	$55.10	4.85%	5.09%	3.50%	13.49%	13.60%	10.20%	8.43%	15.29%	18.78%
DTE Energy Company	DTE	$4.36	$132.97	3.28%	3.39%	4.50%	7.87%	7.60%	6.66%	7.85%	10.05%	11.28%
Duke Energy Corporation	DUK	$4.18	$117.26	3.56%	3.68%	6.00%	6.32%	6.30%	6.21%	9.67%	9.88%	9.99%
Entergy Corporation	ETR	$2.40	$84.52	2.84%	2.94%	3.00%	8.88%	9.50%	7.13%	5.88%	10.07%	12.47%
Evergy, Inc.	EVRG	$2.67	$67.12	3.98%	4.10%	7.50%	5.72%	5.70%	6.31%	9.79%	10.41%	11.63%
IDACORP, Inc.	IDA	$3.44	$114.74	3.00%	3.11%	6.00%	8.23%	8.50%	7.58%	9.09%	10.69%	11.63%
NextEra Energy, Inc.	NEE	$2.27	$70.92	3.20%	3.32%	8.50%	7.11%	7.80%	7.80%	10.42%	11.12%	11.83%
NorthWestern Corporation	NWE	$2.64	$54.98	4.80%	4.93%	4.50%	5.94%	6.10%	5.51%	9.41%	10.45%	11.05%
OGE Energy Corporation	OGE	$1.69	$44.89	3.75%	3.87%	6.50%	5.92%	6.10%	6.17%	9.78%	10.04%	10.38%
Pinnacle West Capital Corporation	PNW	$3.58	$92.41	3.87%	3.95%	4.00%	5.55%	2.10%	3.88%	6.01%	7.83%	9.54%
TXNM Energy	TXNM	$1.63	$52.10	3.13%	3.20%	4.00%	6.55%	3.00%	4.52%	6.18%	7.71%	9.78%
Portland General Electric Company	POR	$2.00	$43.72	4.57%	4.69%	5.50%	6.54%	3.40%	5.15%	8.05%	9.84%	11.26%
PPL Corporation	PPL	$1.09	$34.58	3.15%	3.27%	7.50%	7.27%	6.80%	7.19%	10.06%	10.46%	10.77%
Southern Company	SO	$2.88	$89.46	3.22%	3.32%	6.50%	6.33%	6.50%	6.44%	9.66%	9.77%	9.82%
Xcel Energy Inc.	XEL	$2.28	$69.25	3.29%	3.41%	6.50%	7.26%	6.90%	6.89%	9.90%	10.29%	10.67%
Mean				3.64%	3.75%	5.71%	7.12%	6.62%	6.48%	8.92%	10.24%	11.18%
Median				3.29%	3.41%	6.00%	6.69%	6.50%	6.50%	9.47%	10.07%	10.77%

Notes:
[1] Bloomberg Professional as of March 31, 2025
[2] Bloomberg Professional 30-day average as of March 31, 2025
[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	$2.03	$60.82	3.34%	3.45%	6.00%	6.81%	6.70%	6.50%	9.44%	9.95%	10.27%
Ameren Corporation	AEE	$2.84	$93.92	3.02%	3.12%	6.50%	6.88%	6.70%	6.69%	9.62%	9.82%	10.00%
American Electric Power Company, Inc.	AEP	$3.72	$98.66	3.77%	3.89%	6.50%	6.69%	6.30%	6.50%	10.19%	10.39%	10.59%
Avista Corporation	AVA	$1.96	$37.40	5.24%	5.39%	5.50%	5.88%	6.10%	5.83%	10.89%	11.22%	11.50%
Dominion Resources, Inc.	D	$2.67	$54.68	4.88%	5.13%	3.50%	13.49%	13.60%	10.20%	8.47%	15.33%	18.81%
DTE Energy Company	DTE	$4.36	$124.60	3.50%	3.62%	4.50%	7.87%	7.60%	6.66%	8.08%	10.27%	11.51%
Duke Energy Corporation	DUK	$4.18	$112.46	3.72%	3.83%	6.00%	6.32%	6.30%	6.21%	9.83%	10.04%	10.15%
Entergy Corporation	ETR	$2.40	$79.73	3.01%	3.12%	3.00%	8.88%	9.50%	7.13%	6.06%	10.24%	12.65%
Evergy, Inc.	EVRG	$2.67	$63.99	4.17%	4.30%	7.50%	5.72%	5.70%	6.31%	9.99%	10.61%	11.83%
IDACORP, Inc.	IDA	$3.44	$112.27	3.06%	3.18%	6.00%	8.23%	8.50%	7.58%	9.16%	10.76%	11.69%
NextEra Energy, Inc.	NEE	$2.27	$71.43	3.17%	3.30%	8.50%	7.11%	7.80%	7.80%	10.39%	11.10%	11.81%
NorthWestern Corporation	NWE	$2.64	$53.45	4.94%	5.08%	4.50%	5.94%	6.10%	5.51%	9.55%	10.59%	11.19%
OGE Energy Corporation	OGE	$1.69	$42.98	3.92%	4.04%	6.50%	5.92%	6.10%	6.17%	9.95%	10.21%	10.55%
Pinnacle West Capital Corporation	PNW	$3.58	$88.77	4.03%	4.11%	4.00%	5.55%	2.10%	3.88%	6.18%	8.00%	9.70%
TXNM Energy	TXNM	$1.63	$49.45	3.30%	3.37%	4.00%	6.55%	3.00%	4.52%	6.35%	7.89%	9.95%
Portland General Electric Company	POR	$2.00	$43.19	4.63%	4.75%	5.50%	6.54%	3.40%	5.15%	8.11%	9.90%	11.32%
PPL Corporation	PPL	$1.09	$33.46	3.26%	3.38%	7.50%	7.27%	6.80%	7.19%	10.17%	10.57%	10.88%
Southern Company	SO	$2.88	$85.62	3.36%	3.47%	6.50%	6.33%	6.50%	6.44%	9.80%	9.92%	9.97%
Xcel Energy Inc.	XEL	$2.28	$67.82	3.36%	3.48%	6.50%	7.26%	6.90%	6.89%	9.97%	10.36%	10.74%
Mean				3.77%	3.90%	5.71%	7.12%	6.62%	6.48%	9.06%	10.38%	11.32%
Median				3.50%	3.62%	6.00%	6.69%	6.50%	6.50%	9.62%	10.27%	10.88%

Notes:
[1] Bloomberg Professional as of March 31, 2025
[2] Bloomberg Professional 90-day average as of March 31, 2025
[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

	[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	$2.03	$59.14	3.43%	3.54%	6.00%	6.81%	6.70%	6.50%	9.54%	10.05%	10.36%
Ameren Corporation	AEE	$2.84	$88.17	3.22%	3.33%	6.50%	6.88%	6.70%	6.69%	9.83%	10.02%	10.21%
American Electric Power Company, Inc.	AEP	$3.72	$97.70	3.81%	3.93%	6.50%	6.69%	6.30%	6.50%	10.23%	10.43%	10.63%
Avista Corporation	AVA	$1.96	$37.20	5.27%	5.42%	5.50%	5.88%	6.10%	5.83%	10.91%	11.25%	11.53%
Dominion Resources, Inc.	D	$2.67	$54.80	4.87%	5.12%	3.50%	13.49%	13.60%	10.20%	8.46%	15.32%	18.80%
DTE Energy Company	DTE	$4.36	$122.55	3.56%	3.68%	4.50%	7.87%	7.60%	6.66%	8.14%	10.33%	11.57%
Duke Energy Corporation	DUK	$4.18	$111.84	3.74%	3.85%	6.00%	6.32%	6.30%	6.21%	9.85%	10.06%	10.17%
Entergy Corporation	ETR	$2.40	$71.01	3.38%	3.50%	3.00%	8.88%	9.50%	7.13%	6.43%	10.63%	13.04%
Evergy, Inc.	EVRG	$2.67	$61.15	4.37%	4.50%	7.50%	5.72%	5.70%	6.31%	10.19%	10.81%	12.03%
IDACORP, Inc.	IDA	$3.44	$106.75	3.22%	3.34%	6.00%	8.23%	8.50%	7.58%	9.32%	10.92%	11.86%
NextEra Energy, Inc.	NEE	$2.27	$74.78	3.03%	3.15%	8.50%	7.11%	7.80%	7.80%	10.25%	10.95%	11.66%
NorthWestern Corporation	NWE	$2.64	$53.10	4.97%	5.11%	4.50%	5.94%	6.10%	5.51%	9.58%	10.62%	11.22%
OGE Energy Corporation	OGE	$1.69	$41.11	4.10%	4.23%	6.50%	5.92%	6.10%	6.17%	10.14%	10.40%	10.73%
Pinnacle West Capital Corporation	PNW	$3.58	$87.11	4.11%	4.19%	4.00%	5.55%	2.10%	3.88%	6.25%	8.07%	9.78%
TXNM Energy	TXNM	$1.63	$45.50	3.58%	3.66%	4.00%	6.55%	3.00%	4.52%	6.64%	8.18%	10.25%
Portland General Electric Company	POR	$2.00	$44.59	4.49%	4.60%	5.50%	6.54%	3.40%	5.15%	7.96%	9.75%	11.17%
PPL Corporation	PPL	$1.09	$32.23	3.38%	3.50%	7.50%	7.27%	6.80%	7.19%	10.30%	10.69%	11.01%
Southern Company	SO	$2.88	$85.89	3.35%	3.46%	6.50%	6.33%	6.50%	6.44%	9.79%	9.91%	9.96%
Xcel Energy Inc.	XEL	$2.28	$64.31	3.55%	3.67%	6.50%	7.26%	6.90%	6.89%	10.16%	10.55%	10.93%
Mean				3.86%	3.99%	5.71%	7.12%	6.62%	6.48%	9.16%	10.47%	11.42%
Median				3.58%	3.68%	6.00%	6.69%	6.50%	6.50%	9.79%	10.43%	11.01%

Notes:
[1] Bloomberg Professional as of March 31, 2025
[2] Bloomberg Professional 180-day average as of March 31, 2025
[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 (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.61%	0.95	12.58%	7.97%	12.18%	12.28%
Ameren Corporation	AEE	4.61%	0.90	12.58%	7.97%	11.78%	11.98%
American Electric Power Company, Inc.	AEP	4.61%	0.85	12.58%	7.97%	11.39%	11.69%
Avista Corporation	AVA	4.61%	0.95	12.58%	7.97%	12.18%	12.28%
Dominion Resources, Inc.	D	4.61%	0.90	12.58%	7.97%	11.78%	11.98%
DTE Energy Company	DTE	4.61%	1.00	12.58%	7.97%	12.58%	12.58%
Duke Energy Corporation	DUK	4.61%	0.90	12.58%	7.97%	11.78%	11.98%
Entergy Corporation	ETR	4.61%	1.00	12.58%	7.97%	12.58%	12.58%
Evergy, Inc.	EVRG	4.61%	0.95	12.58%	7.97%	12.18%	12.28%
IDACORP, Inc.	IDA	4.61%	0.85	12.58%	7.97%	11.39%	11.69%
NextEra Energy, Inc.	NEE	4.61%	1.05	12.58%	7.97%	12.98%	12.88%
NorthWestern Corporation	NWE	4.61%	1.00	12.58%	7.97%	12.58%	12.58%
OGE Energy Corporation	OGE	4.61%	1.05	12.58%	7.97%	12.98%	12.88%
Pinnacle West Capital Corporation	PNW	4.61%	0.95	12.58%	7.97%	12.18%	12.28%
TXNM Energy	TXNM	4.61%	0.90	12.58%	7.97%	11.78%	11.98%
Portland General Electric Company	POR	4.61%	0.95	12.58%	7.97%	12.18%	12.28%
PPL Corporation	PPL	4.61%	1.10	12.58%	7.97%	13.38%	13.18%
Southern Company	SO	4.61%	0.95	12.58%	7.97%	12.18%	12.28%
Xcel Energy Inc.	XEL	4.61%	0.85	12.58%	7.97%	11.39%	11.69%
Mean						12.18%	12.28%
Median						12.18%	12.28%

Notes:
[1] Bloomberg Professional 30-day average as of March 31, 2025
[2] Value Line
[3] Market Return
[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.52%	0.95	12.58%	8.06%	12.18%	12.28%
Ameren Corporation	AEE	4.52%	0.90	12.58%	8.06%	11.78%	11.98%
American Electric Power Company, Inc.	AEP	4.52%	0.85	12.58%	8.06%	11.37%	11.68%
Avista Corporation	AVA	4.52%	0.95	12.58%	8.06%	12.18%	12.28%
Dominion Resources, Inc.	D	4.52%	0.90	12.58%	8.06%	11.78%	11.98%
DTE Energy Company	DTE	4.52%	1.00	12.58%	8.06%	12.58%	12.58%
Duke Energy Corporation	DUK	4.52%	0.90	12.58%	8.06%	11.78%	11.98%
Entergy Corporation	ETR	4.52%	1.00	12.58%	8.06%	12.58%	12.58%
Evergy, Inc.	EVRG	4.52%	0.95	12.58%	8.06%	12.18%	12.28%
IDACORP, Inc.	IDA	4.52%	0.85	12.58%	8.06%	11.37%	11.68%
NextEra Energy, Inc.	NEE	4.52%	1.05	12.58%	8.06%	12.99%	12.88%
NorthWestern Corporation	NWE	4.52%	1.00	12.58%	8.06%	12.58%	12.58%
OGE Energy Corporation	OGE	4.52%	1.05	12.58%	8.06%	12.99%	12.88%
Pinnacle West Capital Corporation	PNW	4.52%	0.95	12.58%	8.06%	12.18%	12.28%
TXNM Energy	TXNM	4.52%	0.90	12.58%	8.06%	11.78%	11.98%
Portland General Electric Company	POR	4.52%	0.95	12.58%	8.06%	12.18%	12.28%
PPL Corporation	PPL	4.52%	1.10	12.58%	8.06%	13.39%	13.19%
Southern Company	SO	4.52%	0.95	12.58%	8.06%	12.18%	12.28%
Xcel Energy Inc.	XEL	4.52%	0.85	12.58%	8.06%	11.37%	11.68%
Mean						12.18%	12.28%
Median						12.18%	12.28%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2
[2] Value Line
[3] Market Return
[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
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.30%	0.95	12.58%	8.28%	12.17%	12.27%
Ameren Corporation	AEE	4.30%	0.90	12.58%	8.28%	11.75%	11.96%
American Electric Power Company, Inc.	AEP	4.30%	0.85	12.58%	8.28%	11.34%	11.65%
Avista Corporation	AVA	4.30%	0.95	12.58%	8.28%	12.17%	12.27%
Dominion Resources, Inc.	D	4.30%	0.90	12.58%	8.28%	11.75%	11.96%
DTE Energy Company	DTE	4.30%	1.00	12.58%	8.28%	12.58%	12.58%
Duke Energy Corporation	DUK	4.30%	0.90	12.58%	8.28%	11.75%	11.96%
Entergy Corporation	ETR	4.30%	1.00	12.58%	8.28%	12.58%	12.58%
Evergy, Inc.	EVRG	4.30%	0.95	12.58%	8.28%	12.17%	12.27%
IDACORP, Inc.	IDA	4.30%	0.85	12.58%	8.28%	11.34%	11.65%
NextEra Energy, Inc.	NEE	4.30%	1.05	12.58%	8.28%	13.00%	12.89%
NorthWestern Corporation	NWE	4.30%	1.00	12.58%	8.28%	12.58%	12.58%
OGE Energy Corporation	OGE	4.30%	1.05	12.58%	8.28%	13.00%	12.89%
Pinnacle West Capital Corporation	PNW	4.30%	0.95	12.58%	8.28%	12.17%	12.27%
TXNM Energy	TXNM	4.30%	0.90	12.58%	8.28%	11.75%	11.96%
Portland General Electric Company	POR	4.30%	0.95	12.58%	8.28%	12.17%	12.27%
PPL Corporation	PPL	4.30%	1.10	12.58%	8.28%	13.41%	13.20%
Southern Company	SO	4.30%	0.95	12.58%	8.28%	12.17%	12.27%
Xcel Energy Inc.	XEL	4.30%	0.85	12.58%	8.28%	11.34%	11.65%
Mean						12.17%	12.27%
Median						12.17%	12.27%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14

[2] Value Line

[3] Market Return

[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 BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.61%	0.77	12.58%	7.97%	10.74%	11.20%
Ameren Corporation	AEE	4.61%	0.73	12.58%	7.97%	10.45%	10.98%
American Electric Power Company, Inc.	AEP	4.61%	0.74	12.58%	7.97%	10.48%	11.00%
Avista Corporation	AVA	4.61%	0.74	12.58%	7.97%	10.52%	11.04%
Dominion Resources, Inc.	D	4.61%	0.69	12.58%	7.97%	10.09%	10.71%
DTE Energy Company	DTE	4.61%	0.80	12.58%	7.97%	10.97%	11.37%
Duke Energy Corporation	DUK	4.61%	0.70	12.58%	7.97%	10.23%	10.82%
Entergy Corporation	ETR	4.61%	0.84	12.58%	7.97%	11.32%	11.63%
Evergy, Inc.	EVRG	4.61%	0.77	12.58%	7.97%	10.73%	11.19%
IDACORP, Inc.	IDA	4.61%	0.77	12.58%	7.97%	10.74%	11.20%
NextEra Energy, Inc.	NEE	4.61%	0.80	12.58%	7.97%	10.97%	11.37%
NorthWestern Corporation	NWE	4.61%	0.85	12.58%	7.97%	11.37%	11.67%
OGE Energy Corporation	OGE	4.61%	0.90	12.58%	7.97%	11.82%	12.01%
Pinnacle West Capital Corporation	PNW	4.61%	0.80	12.58%	7.97%	11.02%	11.41%
TXNM Energy	TXNM	4.61%	0.81	12.58%	7.97%	11.05%	11.43%
Portland General Electric Company	POR	4.61%	0.77	12.58%	7.97%	10.72%	11.19%
PPL Corporation	PPL	4.61%	0.91	12.58%	7.97%	11.87%	12.05%
Southern Company	SO	4.61%	0.76	12.58%	7.97%	10.66%	11.14%
Xcel Energy Inc.	XEL	4.61%	0.72	12.58%	7.97%	10.32%	10.88%
Mean						10.85%	11.28%
Median						10.74%	11.20%

Notes:
[1] Bloomberg Professional 30-day average as of March 31, 2025
[2] Bloomberg Professional
[3] Market Return
[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 BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.52%	0.77	12.58%	8.06%	10.72%	11.19%
Ameren Corporation	AEE	4.52%	0.73	12.58%	8.06%	10.43%	10.96%
American Electric Power Company, Inc.	AEP	4.52%	0.74	12.58%	8.06%	10.45%	10.99%
Avista Corporation	AVA	4.52%	0.74	12.58%	8.06%	10.50%	11.02%
Dominion Resources, Inc.	D	4.52%	0.69	12.58%	8.06%	10.06%	10.69%
DTE Energy Company	DTE	4.52%	0.80	12.58%	8.06%	10.95%	11.36%
Duke Energy Corporation	DUK	4.52%	0.70	12.58%	8.06%	10.20%	10.80%
Entergy Corporation	ETR	4.52%	0.84	12.58%	8.06%	11.30%	11.62%
Evergy, Inc.	EVRG	4.52%	0.77	12.58%	8.06%	10.71%	11.17%
IDACORP, Inc.	IDA	4.52%	0.77	12.58%	8.06%	10.72%	11.18%
NextEra Energy, Inc.	NEE	4.52%	0.80	12.58%	8.06%	10.95%	11.36%
NorthWestern Corporation	NWE	4.52%	0.85	12.58%	8.06%	11.36%	11.66%
OGE Energy Corporation	OGE	4.52%	0.90	12.58%	8.06%	11.81%	12.00%
Pinnacle West Capital Corporation	PNW	4.52%	0.80	12.58%	8.06%	11.01%	11.40%
TXNM Energy	TXNM	4.52%	0.81	12.58%	8.06%	11.03%	11.42%
Portland General Electric Company	POR	4.52%	0.77	12.58%	8.06%	10.70%	11.17%
PPL Corporation	PPL	4.52%	0.91	12.58%	8.06%	11.86%	12.04%
Southern Company	SO	4.52%	0.76	12.58%	8.06%	10.64%	11.13%
Xcel Energy Inc.	XEL	4.52%	0.72	12.58%	8.06%	10.29%	10.86%
Mean						10.83%	11.26%
Median						10.72%	11.18%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2
[2] Bloomberg Professional
[3] Market Return
[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
LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.30%	0.77	12.58%	8.28%	10.67%	11.15%
Ameren Corporation	AEE	4.30%	0.73	12.58%	8.28%	10.37%	10.92%
American Electric Power Company, Inc.	AEP	4.30%	0.74	12.58%	8.28%	10.39%	10.94%
Avista Corporation	AVA	4.30%	0.74	12.58%	8.28%	10.44%	10.98%
Dominion Resources, Inc.	D	4.30%	0.69	12.58%	8.28%	9.99%	10.64%
DTE Energy Company	DTE	4.30%	0.80	12.58%	8.28%	10.90%	11.32%
Duke Energy Corporation	DUK	4.30%	0.70	12.58%	8.28%	10.14%	10.75%
Entergy Corporation	ETR	4.30%	0.84	12.58%	8.28%	11.27%	11.60%
Evergy, Inc.	EVRG	4.30%	0.77	12.58%	8.28%	10.65%	11.14%
IDACORP, Inc.	IDA	4.30%	0.77	12.58%	8.28%	10.67%	11.15%
NextEra Energy, Inc.	NEE	4.30%	0.80	12.58%	8.28%	10.90%	11.32%
NorthWestern Corporation	NWE	4.30%	0.85	12.58%	8.28%	11.33%	11.64%
OGE Energy Corporation	OGE	4.30%	0.90	12.58%	8.28%	11.79%	11.99%
Pinnacle West Capital Corporation	PNW	4.30%	0.80	12.58%	8.28%	10.96%	11.37%
TXNM Energy	TXNM	4.30%	0.81	12.58%	8.28%	10.99%	11.39%
Portland General Electric Company	POR	4.30%	0.77	12.58%	8.28%	10.65%	11.13%
PPL Corporation	PPL	4.30%	0.91	12.58%	8.28%	11.85%	12.03%
Southern Company	SO	4.30%	0.76	12.58%	8.28%	10.59%	11.09%
Xcel Energy Inc.	XEL	4.30%	0.72	12.58%	8.28%	10.23%	10.82%
Mean						10.78%	11.23%
Median						10.67%	11.15%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14

[2] Bloomberg Professional

[3] Market Return

[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.61%	0.78	12.58%	7.97%	10.79%	11.24%
Ameren Corporation	AEE	4.61%	0.75	12.58%	7.97%	10.62%	11.11%
American Electric Power Company, Inc.	AEP	4.61%	0.70	12.58%	7.97%	10.16%	10.76%
Avista Corporation	AVA	4.61%	0.81	12.58%	7.97%	11.05%	11.44%
Dominion Resources, Inc.	D	4.61%	0.73	12.58%	7.97%	10.46%	10.99%
DTE Energy Company	DTE	4.61%	0.79	12.58%	7.97%	10.92%	11.34%
Duke Energy Corporation	DUK	4.61%	0.70	12.58%	7.97%	10.22%	10.81%
Entergy Corporation	ETR	4.61%	0.78	12.58%	7.97%	10.85%	11.29%
Evergy, Inc.	EVRG	4.61%	0.94	12.58%	7.97%	12.10%	12.22%
IDACORP, Inc.	IDA	4.61%	0.75	12.58%	7.97%	10.59%	11.09%
NextEra Energy, Inc.	NEE	4.61%	0.78	12.58%	7.97%	10.82%	11.26%
NorthWestern Corporation	NWE	4.61%	0.78	12.58%	7.97%	10.85%	11.29%
OGE Energy Corporation	OGE	4.61%	0.95	12.58%	7.97%	12.22%	12.31%
Pinnacle West Capital Corporation	PNW	4.61%	0.77	12.58%	7.97%	10.76%	11.21%
TXNM Energy	TXNM	4.61%	0.83	12.58%	7.97%	11.22%	11.56%
Portland General Electric Company	POR	4.61%	0.78	12.58%	7.97%	10.82%	11.26%
PPL Corporation	PPL	4.61%	0.86	12.58%	7.97%	11.45%	11.74%
Southern Company	SO	4.61%	0.70	12.58%	7.97%	10.22%	10.81%
Xcel Energy Inc.	XEL	4.61%	0.69	12.58%	7.97%	10.09%	10.71%
Mean						10.85%	11.29%
Median						10.82%	11.26%

Notes:

[1] Bloomberg Professional 30-day average as of March 31, 2025

[2] Long-Term Beta

[3] Market Return

[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.52%	0.78	12.58%	8.06%	10.77%	11.22%
Ameren Corporation	AEE	4.52%	0.75	12.58%	8.06%	10.60%	11.10%
American Electric Power Company, Inc.	AEP	4.52%	0.70	12.58%	8.06%	10.13%	10.74%
Avista Corporation	AVA	4.52%	0.81	12.58%	8.06%	11.04%	11.42%
Dominion Resources, Inc.	D	4.52%	0.73	12.58%	8.06%	10.43%	10.97%
DTE Energy Company	DTE	4.52%	0.79	12.58%	8.06%	10.90%	11.32%
Duke Energy Corporation	DUK	4.52%	0.70	12.58%	8.06%	10.20%	10.79%
Entergy Corporation	ETR	4.52%	0.78	12.58%	8.06%	10.84%	11.27%
Evergy, Inc.	EVRG	4.52%	0.94	12.58%	8.06%	12.10%	12.22%
IDACORP, Inc.	IDA	4.52%	0.75	12.58%	8.06%	10.57%	11.07%
NextEra Energy, Inc.	NEE	4.52%	0.78	12.58%	8.06%	10.80%	11.25%
NorthWestern Corporation	NWE	4.52%	0.78	12.58%	8.06%	10.84%	11.27%
OGE Energy Corporation	OGE	4.52%	0.95	12.58%	8.06%	12.21%	12.31%
Pinnacle West Capital Corporation	PNW	4.52%	0.77	12.58%	8.06%	10.73%	11.20%
TXNM Energy	TXNM	4.52%	0.83	12.58%	8.06%	11.20%	11.55%
Portland General Electric Company	POR	4.52%	0.78	12.58%	8.06%	10.80%	11.25%
PPL Corporation	PPL	4.52%	0.86	12.58%	8.06%	11.44%	11.73%
Southern Company	SO	4.52%	0.70	12.58%	8.06%	10.20%	10.79%
Xcel Energy Inc.	XEL	4.52%	0.69	12.58%	8.06%	10.06%	10.69%
Mean						10.83%	11.27%
Median						10.80%	11.25%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2
[2] Long-Term Beta
[3] Market Return
[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
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.30%	0.78	12.58%	8.28%	10.72%	11.18%
Ameren Corporation	AEE	4.30%	0.75	12.58%	8.28%	10.55%	11.06%
American Electric Power Company, Inc.	AEP	4.30%	0.70	12.58%	8.28%	10.06%	10.69%
Avista Corporation	AVA	4.30%	0.81	12.58%	8.28%	10.99%	11.39%
Dominion Resources, Inc.	D	4.30%	0.73	12.58%	8.28%	10.37%	10.93%
DTE Energy Company	DTE	4.30%	0.79	12.58%	8.28%	10.86%	11.29%
Duke Energy Corporation	DUK	4.30%	0.70	12.58%	8.28%	10.13%	10.74%
Entergy Corporation	ETR	4.30%	0.78	12.58%	8.28%	10.79%	11.24%
Evergy, Inc.	EVRG	4.30%	0.94	12.58%	8.28%	12.09%	12.21%
IDACORP, Inc.	IDA	4.30%	0.75	12.58%	8.28%	10.51%	11.03%
NextEra Energy, Inc.	NEE	4.30%	0.78	12.58%	8.28%	10.75%	11.21%
NorthWestern Corporation	NWE	4.30%	0.78	12.58%	8.28%	10.79%	11.24%
OGE Energy Corporation	OGE	4.30%	0.95	12.58%	8.28%	12.20%	12.30%
Pinnacle West Capital Corporation	PNW	4.30%	0.77	12.58%	8.28%	10.68%	11.16%
TXNM Energy	TXNM	4.30%	0.83	12.58%	8.28%	11.17%	11.52%
Portland General Electric Company	POR	4.30%	0.78	12.58%	8.28%	10.75%	11.21%
PPL Corporation	PPL	4.30%	0.86	12.58%	8.28%	11.41%	11.70%
Southern Company	SO	4.30%	0.70	12.58%	8.28%	10.13%	10.74%
Xcel Energy Inc.	XEL	4.30%	0.69	12.58%	8.28%	9.99%	10.64%
Mean						10.79%	11.24%
Median						10.75%	11.21%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14

[2] Long-Term Beta

[3] Market Return

[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] 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	0.78
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
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
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	0.81
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	0.73
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	0.79
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	0.70
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	0.78
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.90	0.90	0.95	0.94
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	0.75
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	0.78
NorthWestern Corporation	NWE	0.70	0.70	0.70	0.70	0.70	0.55	0.60	0.95	0.95	0.90	0.95	1.00	0.78
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	0.95
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	0.77
TXNM Energy	TXNM	0.95	0.85	0.80	0.75	0.75	0.65	0.60	0.95	0.95	0.90	0.90	0.90	0.83
Portland General Electric Company	POR	0.75	0.80	0.80	0.70	0.70	0.60	0.55	0.85	0.90	0.85	0.90	0.95	0.78
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	0.86
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	0.70
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	0.69
Mean		0.73	0.73	0.74	0.68	0.69	0.59	0.57	0.91	0.91	0.89	0.92	0.95	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] Average ([1] - [12])

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.36%
[2] Estimate of the S&P 500 Growth Rate	11.15%
[3] S&P 500 Estimated Required Market Return	12.58%

		[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	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	323.44617	70.4	22,770.61	0.07%	7.61%	0.00%	11.14%	0.01%
American Express Co	AXP	701.10952	269.05	188,633.52	0.54%	1.22%	0.01%	15.16%	0.08%
Verizon Communications Inc	VZ	4209.70396	45.36	190,952.17	0.55%	5.97%	0.03%	1.43%	0.01%
Texas Pacific Land Corp	TPL	22.9848	1324.99	30,454.63		0.48%			
Broadcom Inc	AVGO	4701.94872	167.43	787,247.27		1.41%		23.48%	
Boeing Co/The	BA	752.40749	170.55	128,323.10				30.85%	
Solventum Corp	SOLV	173.00293	76.04	13,155.14				-0.35%	
Caterpillar Inc	CAT	477.93202	329.8	157,621.98	0.45%	1.71%	0.01%	7.23%	0.03%
JPMorgan Chase & Co	JPM	2796.1061	245.3	685,884.83		2.28%			
Chevron Corp	CVX	1749.71578	167.29	292,709.95		4.09%			
Coca-Cola Co/The	KO	4303.56681	71.62	308,221.45	0.89%	2.85%	0.03%	5.69%	0.05%
AbbVie Inc	ABBV	1768.97828	209.52	370,636.33	1.07%	3.13%	0.03%	15.54%	0.17%
Walt Disney Co/The	DIS	1807.78887	98.7	178,428.76	0.51%	1.01%	0.01%	11.36%	0.06%
Corpay Inc	CPAY	70.24992	348.72	24,497.55	0.07%			12.58%	0.01%
Extra Space Storage Inc	EXR	211.99813	148.49	31,479.60		4.36%			
Exxon Mobil Corp	XOM	4339.14331	118.93	516,054.31		3.33%			
Phillips 66	PSX	407.69835	123.48	50,342.59		3.73%			
General Electric Co	GE	1066.57876	200.15	213,475.74	0.61%	0.72%	0.00%	18.22%	0.11%
HP Inc	HPQ	942.70303	27.69	26,103.45	0.08%	4.18%	0.00%	1.55%	0.00%
Home Depot Inc/The	HD	994.03217	366.49	364,302.85	1.05%	2.51%	0.03%	5.11%	0.05%
Monolithic Power Systems Inc	MPWR	47.866	579.98	27,761.32		1.08%			
International Business Machines Corp	IBM	927.26433	248.66	230,573.55	0.66%	2.69%	0.02%	3.46%	0.02%
Johnson & Johnson	JNJ	2409.84773	165.84	399,649.15		2.99%			
Lululemon Athletica Inc	LULU	115.52123	283.06	32,699.44	0.09%			9.55%	0.01%
McDonald's Corp	MCD	714.46114	312.37	223,176.23	0.64%	2.27%	0.01%	9.12%	0.06%
Merck & Co Inc	MRK	2526.03624	89.76	226,737.01	0.65%	3.61%	0.02%	14.65%	0.10%
3M Co	MMM	539.31834	146.86	79,204.29	0.23%	1.99%	0.00%	6.59%	0.02%
American Water Works Co Inc	AWK	195.01095	147.52	28,768.02		2.07%			
Bank of America Corp	BAC	7602.79833	41.73	317,264.77		2.49%			
Pfizer Inc	PFE	5671.45477	25.34	143,714.66		6.79%		-2.32%	
Procter & Gamble Co/The	PG	2344.85181	170.42	399,609.65	1.15%	2.36%	0.03%	6.24%	0.07%
AT&T Inc	T	7178.183	28.28	202,999.02	0.58%	3.93%	0.02%	5.16%	0.03%
Travelers Cos Inc/The	TRV	226.72658	264.46	59,960.11	0.17%	1.59%	0.00%	1.10%	0.00%
RTX Corp	RTX	1335.08992	132.46	176,846.01	0.51%	1.90%	0.01%	8.65%	0.04%
Analog Devices Inc	ADI	495.97648	201.67	100,023.58	0.29%	1.96%	0.01%	11.79%	0.03%
Walmart Inc	WMT	8016.84944	87.79	703,799.21	2.03%	1.07%	0.02%	7.43%	0.15%
Cisco Systems Inc	CSCO	3978.29243	61.71	245,500.43	0.71%	2.66%	0.02%	4.69%	0.03%
Intel Corp	INTC	4360.59164	22.71	99,029.04				28.44%	
General Motors Co	GM	995.00189	47.03	46,794.94	0.13%	1.02%	0.00%	8.53%	0.01%
Microsoft Corp	MSFT	7433.98224	375.39	2,790,642.59	8.03%	0.88%	0.07%	13.09%	1.05%
Dollar General Corp	DG	219.94708	87.93	19,339.95	0.06%	2.68%	0.00%	5.74%	0.00%
Cigna Group/The	CI	271.1081	329	89,194.56	0.26%	1.84%	0.00%	5.07%	0.01%
Kinder Morgan Inc	KMI	2221.96303	28.53	63,392.61		4.03%			
Citigroup Inc	C	1882.16004	70.99	133,614.54		3.16%			
American International Group Inc	AIG	593.33296	86.94	51,584.37	0.15%	1.84%	0.00%	12.18%	0.02%
Altria Group Inc	MO	1690.66164	60.02	101,473.51	0.29%	6.80%	0.02%	4.48%	0.01%
HCA Healthcare Inc	HCA	246.2033	345.55	85,075.55	0.24%	0.83%	0.00%	9.26%	0.02%
International Paper Co	IP	526.12561	53.35	28,068.80		3.47%			
Hewlett Packard Enterprise Co	HPE	1313.57824	15.43	20,268.51	0.06%	3.37%	0.00%	4.02%	0.00%
Abbott Laboratories	ABT	1734.32341	132.65	230,058.00	0.66%	1.78%	0.01%	10.26%	0.07%
Aflac Inc	AFL	545.8146	111.19	60,689.13	0.17%	2.09%	0.00%	4.80%	0.01%
Air Products and Chemicals Inc	APD	222.47567	293.1301	65,214.32	0.19%	2.44%	0.00%	6.37%	0.01%
Super Micro Computer Inc	SMCI	593.48135	34.24	20,320.80					
Royal Caribbean Cruises Ltd	RCL	269.12875	205.44	55,289.81	0.16%	1.46%	0.00%	19.67%	0.03%
Hess Corp	HES	308.29166	159.73	49,243.43		1.25%			
Lennox International Inc	LII	35.57966	560.83	19,954.14		0.82%			
Archer-Daniels-Midland Co	ADM	480.15568	48.01	23,052.27	0.07%	4.25%	0.00%	7.27%	0.00%
Automatic Data Processing Inc	ADP	406.87089	305.53	124,311.26	0.36%	2.02%	0.01%	9.07%	0.03%
Verisk Analytics Inc	VRSK	140.27617	297.62	41,748.99		0.60%			
AutoZone Inc	AZO	16.72866	3812.78	63,782.70	0.18%			9.56%	0.02%
Linde PLC	LIN	472.91162	465.64	220,206.57	0.63%	1.29%	0.01%	8.04%	0.05%
Avery Dennison Corp	AVY	78.966	177.97	14,053.58	0.04%	1.98%	0.00%	8.96%	0.00%
Enphase Energy Inc	ENPH	132.47051	62.05	8,219.80					
MSCI Inc	MSCI	77.60163	565.5	43,883.72		1.27%			
Ball Corp	BALL	282.37887	52.07	14,703.47	0.04%	1.54%	0.00%	11.85%	0.01%
Axon Enterprise Inc	AXON	76.62327	525.95	40,300.01				27.80%	
Dayforce Inc	DAY	158.26236	58.33	9,231.44					
Carrier Global Corp	CARR	863.98757	63.4	54,776.81	0.16%	1.42%	0.00%	13.57%	0.02%
Bank of New York Mellon Corp/The	BK	717.97392	83.87	60,216.47	0.17%	2.24%	0.00%	12.56%	0.02%
Otis Worldwide Corp	OTIS	396.51856	103.2	40,920.72		1.51%			
Baxter International Inc	BAX	512.92407	34.23	17,557.39	0.05%	1.99%	0.00%	14.67%	0.01%
Becton Dickinson & Co	BDX	287.13542	229.06	65,771.24	0.19%	1.82%	0.00%	9.31%	0.02%
Berkshire Hathaway Inc	BRK/B	1339.90564	532.58	713,606.95					
Best Buy Co Inc	BBY	211.36966	73.61	15,558.92	0.04%	5.16%	0.00%	5.78%	0.00%
Boston Scientific Corp	BSX	1479.0702	100.88	149,208.60	0.43%			12.77%	0.05%
Bristol-Myers Squibb Co	BMY	2034.7632	60.99	124,100.21		4.07%		82.16%	
Brown-Forman Corp	BF/B	303.53996	33.94	10,302.15		2.67%		-2.71%	
Coterra Energy Inc	CTRA	764.09613	28.9	22,082.38	0.06%	3.04%	0.00%	15.54%	0.01%
Hilton Worldwide Holdings Inc	HLT	239.61402	227.55	54,524.17	0.16%	0.26%	0.00%	13.66%	0.02%
Carnival Corp	CCL	1166.60698	19.53	22,783.83				25.25%	
Builders FirstSource Inc	BLDR	113.62137	124.94	14,195.85	0.04%			8.55%	0.00%
UDR Inc	UDR	331.13336	45.17	14,957.29	0.04%	3.81%	0.00%	1.98%	0.00%

		[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	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Clorox Co/The	CLX	123.18987	147.25	18,139.71	0.05%	3.31%	0.00%	8.97%	0.00%
Paycom Software Inc	PAYC	57.26472	218.48	12,511.20	0.04%	0.69%	0.00%	7.82%	0.00%
CMS Energy Corp	CMS	299.11468	75.11	22,466.50	0.06%	2.89%	0.00%	7.64%	0.00%
Colgate-Palmolive Co	CL	811.08435	93.7	75,998.60	0.22%	2.22%	0.00%	5.69%	0.01%
EPAM Systems Inc	EPAM	56.88813	168.84	9,604.99					
Conagra Brands Inc	CAG	477.32046	26.67	12,730.14		5.25%		-3.22%	
Airbnb Inc	ABNB	440.00213	119.46	52,562.65	0.15%			10.66%	0.02%
Consolidated Edison Inc	ED	353.07173	110.59	39,046.20	0.11%	3.07%	0.00%	4.89%	0.01%
Corning Inc	GLW	856.77702	45.78	39,223.25	0.11%	2.45%	0.00%	17.92%	0.02%
GoDaddy Inc	GDDY	141.35591	180.14	25,463.85					
Cummins Inc	CMI	137.48116	313.44	43,092.09	0.12%	2.32%	0.00%	10.37%	0.01%
Caesars Entertainment Inc	CZR	212.01331	25	5,300.33				51.64%	
Danaher Corp	DHR	715.45028	205	146,667.31	0.42%	0.62%	0.00%	8.67%	0.04%
Target Corp	TGT	455.57646	104.36	47,543.96	0.14%	4.29%	0.01%	11.25%	0.02%
Williams-Sonoma Inc	WSM	123.5095	158.1	19,526.85	0.06%	1.67%	0.00%	4.50%	0.00%
Deere & Co	DE	271.41393	469.35	127,388.13	0.37%	1.38%	0.01%	0.48%	0.00%
Dominion Energy Inc	D	852.21519	56.07	47,783.71		4.76%		23.10%	
Dover Corp	DOV	137.06227	175.68	24,079.10	0.07%	1.17%	0.00%	10.22%	0.01%
Alliant Energy Corp	LNT	256.69238	64.35	16,518.15	0.05%	3.15%	0.00%	6.14%	0.00%
Steel Dynamics Inc	STLD	149.89679	125.08	18,749.09	0.05%	1.60%	0.00%	14.29%	0.01%
Duke Energy Corp	DUK	777.02168	121.97	94,773.33	0.27%	3.43%	0.01%	7.90%	0.02%
Regency Centers Corp	REG	181.52587	73.76	13,389.35	0.04%	3.82%	0.00%	4.59%	0.00%
Eaton Corp PLC	ETN	391.76938	271.83	106,494.67	0.31%	1.53%	0.00%	11.73%	0.04%
Ecolab Inc	ECL	283.63255	253.52	71,906.52	0.21%	1.03%	0.00%	12.49%	0.03%
Revvity Inc	RVTY	120.14729	105.8	12,711.58	0.04%	0.26%	0.00%	8.81%	0.00%
Dell Technologies Inc	DELL	358.71036	91.15	32,696.45	0.09%	2.30%	0.00%	12.40%	0.01%
Emerson Electric Co	EMR	563.9	109.64	61,826.00	0.18%	1.92%	0.00%	8.28%	0.01%
EOG Resources Inc	EOG	551.5444	128.24	70,730.05		3.04%		-3.30%	
Aon PLC	AON	216.00111	399.09	86,203.88	0.25%	0.68%	0.00%	10.68%	0.03%
Entergy Corp	ETR	446.34088	85.49	38,157.68	0.11%	2.81%	0.00%	7.73%	0.01%
Equifax Inc	EFX	124.79869	243.56	30,395.97		0.64%			
EQT Corp	EQT	597.441	53.43	31,921.27		1.18%			
IQVIA Holdings Inc	IQV	176.31504	176.3	31,084.34	0.09%			8.80%	0.01%
Gartner Inc	IT	76.81819	419.74	32,243.67					
FedEx Corp	FDX	239.59892	243.78	58,409.42	0.17%	2.26%	0.00%	11.22%	0.02%
Brown & Brown Inc	BRO	286.62761	124.4	35,656.47	0.10%	0.48%	0.00%	9.12%	0.01%
Ford Motor Co	F	3905.6954	10.03	39,174.12	0.11%	1.50%	0.00%	0.18%	0.00%
NextEra Energy Inc	NEE	2057.02628	70.89	145,822.59	0.42%	3.20%	0.01%	7.09%	0.03%
Franklin Resources Inc	BEN	525.39798	19.25	10,113.91		6.65%			
Garmin Ltd	GRMN	192.40378	217.13	41,776.63		1.66%			
Freeport-McMoRan Inc	FCX	1437.07301	37.86	54,407.58	0.16%	1.58%	0.00%	14.30%	0.02%
Expand Energy Corp	EXE	232.69994	111.32	25,904.16		2.07%		-29.49%	
Dexcom Inc	DXCM	392.1075	68.29	26,777.02	0.08%			19.18%	0.01%
General Dynamics Corp	GD	268.38182	272.58	73,155.52	0.21%	2.20%	0.00%	13.45%	0.03%
General Mills Inc	GIS	547.60053	59.79	32,741.04		4.01%		-2.42%	
Genuine Parts Co	GPC	138.78203	119.14	16,534.49		3.46%			
Atmos Energy Corp	ATO	158.7282	154.58	24,536.21	0.07%	2.25%	0.00%	7.27%	0.01%
WW Grainger Inc	GWW	48.17143	987.83	47,585.18	0.14%	0.83%	0.00%	5.85%	0.01%
Halliburton Co	HAL	868.09162	25.37	22,023.48		2.68%		-2.16%	
L3Harris Technologies Inc	LHX	187.71635	209.31	39,290.91	0.11%	2.29%	0.00%	12.47%	0.01%
Healthpeak Properties Inc	DOC	698.59612	20.22	14,125.61	0.04%	6.03%	0.00%	4.91%	0.00%
Insulet Corp	PODD	70.2261	262.61	18,442.08				24.42%	
Fortive Corp	FTV	340.29013	73.18	24,902.43	0.07%	0.44%	0.00%	7.56%	0.01%
Hershey Co/The	HSY	147.94946	171.03	25,303.80		3.20%		-9.26%	
Synchrony Financial	SYF	388.74949	52.94	20,580.40	0.06%	1.89%	0.00%	14.88%	0.01%
Hormel Foods Corp	HRL	549.9125	30.94	17,014.29	0.05%	3.75%	0.00%	7.27%	0.00%
Arthur J Gallagher & Co	AJG	255.7348	345.24	88,289.88		0.75%			
Mondelez International Inc	MDLZ	1293.52517	67.85	87,765.68	0.25%	2.77%	0.01%	0.40%	0.00%
CenterPoint Energy Inc	CNP	652.72675	36.23	23,648.29	0.07%	2.43%	0.00%	8.15%	0.01%
Humana Inc	HUM	120.69263	264.6	31,935.27	0.09%	1.34%	0.00%	6.50%	0.01%
Willis Towers Watson PLC	WTW	99.38082	337.95	33,585.75	0.10%	1.09%	0.00%	7.49%	0.01%
Illinois Tool Works Inc	ITW	293.36598	248.01	72,757.70	0.21%	2.42%	0.01%	1.21%	0.00%
CDW Corp/DE	CDW	132.49227	160.26	21,233.21	0.06%	1.56%	0.00%	6.38%	0.00%
Trane Technologies PLC	TT	224.29096	336.92	75,568.11	0.22%	1.12%	0.00%	9.97%	0.02%
Interpublic Group of Cos Inc/The	IPG	372.64916	27.16	10,121.15		4.86%			
International Flavors & Fragrances Inc	IFF	255.73501	77.61	19,847.59	0.06%	2.06%	0.00%	7.72%	0.00%
Generac Holdings Inc	GNRC	59.61403	126.65	7,550.12	0.02%			19.45%	0.00%
NXP Semiconductors NV	NXPI	253.62012	190.06	48,203.04	0.14%	2.13%	0.00%	4.62%	0.01%
Kellanova	K	345.21592	82.49	28,476.86	0.08%	2.76%	0.00%	4.55%	0.00%
Broadridge Financial Solutions Inc	BR	117.01869	242.46	28,372.35		1.45%			
Kimberly-Clark Corp	KMB	331.65171	142.22	47,167.51	0.14%	3.54%	0.00%	3.87%	0.01%
Kimco Realty Corp	KIM	679.49863	21.24	14,432.55	0.04%	4.71%	0.00%	3.40%	0.00%
Oracle Corp	ORCL	2804.234	139.81	392,059.96	1.13%	1.43%	0.02%	8.75%	0.10%
Kroger Co/The	KR	723.60613	67.69	48,980.90	0.14%	1.89%	0.00%	6.11%	0.01%
Lennar Corp	LEN	232.68541	114.78	26,707.63		1.74%		-1.58%	
Eli Lilly & Co	LLY	947.98915	825.91	782,953.72	2.25%	0.73%	0.02%	20.00%	0.45%
Charter Communications Inc	CHTR	142.01418	368.53	52,336.49	0.15%			18.16%	0.03%
Loews Corp	L	212.8613	91.91	19,564.08		0.27%			
Lowe's Cos Inc	LOW	559.70654	233.23	130,540.36	0.38%	1.97%	0.01%	6.05%	0.02%
Hubbell Inc	HUBB	53.57336	330.91	17,727.96		1.60%			
IDEX Corp	IEX	75.54411	180.97	13,671.22		1.53%			
Marsh & McLennan Cos Inc	MMC	492.90312	244.03	120,283.15	0.35%	1.34%	0.00%	8.55%	0.03%
Masco Corp	MAS	211.65232	69.54	14,718.30	0.04%	1.78%	0.00%	9.14%	0.00%
S&P Global Inc	SPGI	313.84007	508.1	159,462.14		0.76%			
Medtronic PLC	MDT	1282.54351	89.86	115,249.36	0.33%	3.12%	0.01%	6.49%	0.02%
Viatris Inc	VTRS	1193.68875	8.71	10,397.03		5.51%		-3.79%	
CVS Health Corp	CVS	1260.79506	67.75	85,418.87	0.25%	3.93%	0.01%	14.47%	0.04%
DuPont de Nemours Inc	DD	418.04913	74.68	31,219.91	0.09%	2.20%	0.00%	8.02%	0.01%
Micron Technology Inc	MU	1117.57153	86.89	97,105.79		0.53%		86.81%	
Motorola Solutions Inc	MSI	166.96355	437.81	73,098.31	0.21%	1.00%	0.00%	7.04%	0.01%
Cboe Global Markets Inc	CBOE	104.7017	226.29	23,692.95	0.07%	1.11%	0.00%	13.35%	0.01%
Newmont Corp	NEM	1127.25753	48.28	54,423.99		2.07%		-4.72%	
NIKE Inc	NKE	1181.23914	63.48	74,985.06		2.52%		-7.00%	

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Name	Ticker	Shares Outstg	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
NiSource Inc	NI	470.60544	40.09	18,866.57		2.79%			
Norfolk Southern Corp	NSC	246.55807	236.85	58,397.28	0.17%	2.28%	0.00%	11.89%	0.02%
Principal Financial Group Inc	PFG	225.57133	84.37	19,031.45	0.05%	3.56%	0.00%	13.66%	0.01%
Eversource Energy	ES	367.0819	62.11	22,799.46	0.07%	4.85%	0.00%	4.42%	0.00%
Northrop Grumman Corp	NOC	144.75566	512.01	74,116.35	0.21%	1.61%	0.00%	5.70%	0.01%
Wells Fargo & Co	WFC	3265.15883	71.79	234,405.75	0.67%	2.23%	0.02%	16.95%	0.11%
Nucor Corp	NUE	230.74614	120.34	27,767.99	0.08%	1.83%	0.00%	19.06%	0.02%
Occidental Petroleum Corp	OXY	939.78256	49.36	46,387.67		1.94%			
Omnicom Group Inc	OMC	196.5563	82.91	16,296.48	0.05%	3.38%	0.00%	5.45%	0.00%
ONEOK Inc	OKE	624.33959	99.22	61,946.97		4.15%			
Raymond James Financial Inc	RJF	204.91003	138.4101	28,361.62	0.08%	1.44%	0.00%	15.42%	0.01%
PG&E Corp	PCG	2193.5768	17.18	37,685.65		0.58%			
Parker-Hannifin Corp	PH	128.76484	607.85	78,269.71	0.23%	1.07%	0.00%	7.54%	0.02%
Rollins Inc	ROL	485.07563	54.03	26,208.64		1.22%			
PPL Corp	PPL	738.29408	36.11	26,659.80		3.02%			
Aptiv PLC	APTV	229.44637	59.5	13,652.06	0.04%			15.17%	0.01%
ConocoPhillips	COP	1264.16535	105.02	132,762.65	0.38%	2.97%	0.01%	4.50%	0.02%
PulteGroup Inc	PHM	201.5854	102.8	20,722.98	0.06%	0.86%	0.00%	0.98%	0.00%
Pinnacle West Capital Corp	PNW	119.24351	95.25	11,357.94	0.03%	3.76%	0.00%	2.12%	0.00%
PNC Financial Services Group Inc/The	PNC	395.74958	175.77	69,560.90	0.20%	3.64%	0.01%	8.09%	0.02%
PPG Industries Inc	PPG	226.9749	109.35	24,819.71	0.07%	2.49%	0.00%	7.69%	0.01%
DoorDash Inc	DASH	394.48502	182.77	72,100.03					
Progressive Corp/The	PGR	586.23611	283.01	165,910.68	0.48%	0.14%	0.00%	14.79%	0.07%
Veralto Corp	VLTO	248.05176	97.45	24,172.64		0.45%			
Public Service Enterprise Group Inc	PEG	498.56147	82.3	41,031.61	0.12%	3.06%	0.00%	9.40%	0.01%
Cooper Cos Inc/The	COO	199.98118	84.35	16,868.41	0.05%			9.91%	0.00%
Edison International	EIX	385.02353	58.92	22,685.59		5.62%			
Schlumberger NV	SLB	1359.85528	41.8	56,841.95	0.16%	2.73%	0.00%	1.25%	0.00%
Charles Schwab Corp/The	SCHW	1813.56767	78.28	141,966.08		1.38%			
Sherwin-Williams Co/The	SHW	251.51015	349.19	87,824.83	0.25%	0.90%	0.00%	6.20%	0.02%
West Pharmaceutical Services Inc	WST	72.29273	223.88	16,184.90	0.05%	0.38%	0.00%	5.83%	0.00%
J M Smucker Co/The	SJM	106.41662	118.41	12,600.79		3.65%			
Snap-on Inc	SNA	52.41777	337.01	17,665.31	0.05%	2.54%	0.00%	4.26%	0.00%
AMETEK Inc	AME	230.74691	172.14	39,720.77	0.11%	0.72%	0.00%	8.60%	0.01%
Uber Technologies Inc	UBER	2091.25811	72.86	152,369.07				-6.02%	
Southern Co/The	SO	1094.63342	91.95	100,651.54	0.29%	3.13%	0.01%	6.37%	0.02%
Truist Financial Corp	TFC	1305.39071	41.15	53,716.83	0.15%	5.05%	0.01%	8.22%	0.01%
Southwest Airlines Co	LUV	592.66108	33.58	19,901.56		2.14%		50.33%	
W R Berkley Corp	WRB	379.22606	71.16	26,985.73	0.08%	0.45%	0.00%	8.92%	0.01%
Stanley Black & Decker Inc	SWK	154.53752	76.88	11,880.84		4.27%			
Public Storage	PSA	175.41553	299.29	52,500.11		4.01%			
Arista Networks Inc	ANET	1261.1226	77.48	97,711.78	0.28%			14.64%	0.04%
Sysco Corp	SYY	489.22964	75.04	36,711.79		2.72%			
Corteva Inc	CTVA	683.01458	62.93	42,982.11	0.12%	1.08%	0.00%	15.89%	0.02%
Texas Instruments Inc	TXN	909.91782	179.7	163,512.23	0.47%	3.03%	0.01%	12.68%	0.06%
Textron Inc	TXT	181.62092	72.25	13,122.11	0.04%	0.11%	0.00%	10.03%	0.00%
Thermo Fisher Scientific Inc	TMO	377.26118	497.6	187,725.16	0.54%	0.35%	0.00%	9.24%	0.05%
TJX Cos Inc/The	TJX	1124.15803	121.8	136,922.45	0.39%	1.40%	0.01%	7.62%	0.03%
Globe Life Inc	GL	83.24275	131.72	10,964.74		0.82%			
Johnson Controls International plc	JCI	660.13919	80.11	52,883.75	0.15%	1.85%	0.00%	9.69%	0.01%
Ulta Beauty Inc	ULTA	45.30949	366.54	16,607.74	0.05%			3.98%	0.00%
Union Pacific Corp	UNP	599.31818	236.24	141,582.93	0.41%	2.27%	0.01%	9.95%	0.04%
Keysight Technologies Inc	KEYS	172.81051	149.77	25,881.83	0.07%			12.64%	0.01%
UnitedHealth Group Inc	UNH	914.71233	523.75	479,080.58	1.38%	1.60%	0.02%	11.45%	0.16%
Blackstone Inc	BX	729.41593	139.78	101,957.76		4.12%		24.94%	
Ventas Inc	VTR	437.61657	68.76	30,090.52	0.09%	2.79%	0.00%	9.17%	0.01%
Labcorp Holdings Inc	LH	83.7	232.74	19,480.34	0.06%	1.24%	0.00%	10.01%	0.01%
Vulcan Materials Co	VMC	132.10118	233.3	30,819.21	0.09%	0.84%	0.00%	13.04%	0.01%
Weyerhaeuser Co	WY	725.84892	29.28	21,252.86	0.06%	2.87%	0.00%	8.13%	0.00%
Williams Cos Inc/The	WMB	1220.68675	59.76	72,948.24		3.35%			
Constellation Energy Corp	CEG	315.12094	201.63	63,537.84	0.18%	0.77%	0.00%	12.12%	0.02%
WEC Energy Group Inc	WEC	315.82083	108.98	34,418.15	0.10%	3.28%	0.00%	7.53%	0.01%
Adobe Inc	ADBE	426.2	383.53	163,460.49	0.47%			13.63%	0.06%
Vistra Corp	VST	340.15707	117.44	39,948.05		0.76%		-5.61%	
AES Corp/The	AES	711.90055	12.42	8,841.80	0.03%	5.67%	0.00%	3.32%	0.00%
Expeditors International of Washington Inc	EXPD	137.7567	120.25	16,565.24	0.05%	1.21%	0.00%	4.35%	0.00%
Amgen Inc	AMGN	537.20494	311.55	167,366.20	0.48%	3.06%	0.01%	6.91%	0.03%
Apple Inc	AAPL	15022.073	222.13	3,336,853.08	9.60%	0.45%	0.04%	14.47%	1.39%
Autodesk Inc	ADSK	213	261.8	55,763.40	0.16%			14.19%	0.02%
Cintas Corp	CTAS	403.54393	205.53	82,940.38		0.76%			
Comcast Corp	CMCSA	3771.57823	36.9	139,171.24	0.40%	3.58%	0.01%	4.62%	0.02%
Molson Coors Beverage Co	TAP	190.15798	60.87	11,574.92	0.03%	3.09%	0.00%	8.44%	0.00%
KLA Corp	KLAC	132.88675	679.8	90,336.41	0.26%	1.00%	0.00%	15.45%	0.04%
Marriott International Inc/MD	MAR	275.37279	238.2	65,593.80	0.19%	1.06%	0.00%	10.85%	0.02%
Fiserv Inc	FI	561.28894	220.83	123,949.44	0.36%			15.74%	0.06%
McCormick & Co Inc/MD	MKC	252.68174	82.31	20,798.23	0.06%	2.19%	0.00%	6.37%	0.00%
PACCAR Inc	PCAR	524.93477	97.37	51,112.90	0.15%	1.36%	0.00%	6.90%	0.01%
Costco Wholesale Corp	COST	443.68336	945.78	419,626.85	1.21%	0.49%	0.01%	8.86%	0.11%
Stryker Corp	SYK	381.68884	372.25	142,083.67	0.41%	0.90%	0.00%	9.83%	0.04%
Tyson Foods Inc	TSN	286.18537	63.81	18,261.49		3.13%		21.06%	
Lamb Weston Holdings Inc	LW	142.6407	53.3	7,602.75		2.78%		-11.26%	
Applied Materials Inc	AMAT	812.44085	145.12	117,901.42	0.34%	1.27%	0.00%	10.64%	0.04%
Cardinal Health Inc	CAH	241.56799	137.2644	33,158.69	0.10%	1.47%	0.00%	9.07%	0.01%
Cincinnati Financial Corp	CINF	156.56473	147.72	23,127.74	0.07%	2.36%	0.00%	2.85%	0.00%
Paramount Global	PARA	630.00763	11.96	7,534.89		1.67%			
DR Horton Inc	DHI	315.12249	127.13	40,061.52	0.12%	1.26%	0.00%	7.26%	0.01%
Electronic Arts Inc	EA	260.61759	144.52	37,664.45	0.11%	0.53%	0.00%	5.98%	0.01%
Erie Indemnity Co	ERIE	46.18907	419.05	19,355.53		1.30%			
Fair Isaac Corp	FICO	24.41814	1844.16	45,030.96					
Fastenal Co	FAST	573.45111	77.55	44,471.13	0.13%	2.22%	0.00%	10.52%	0.01%
M&T Bank Corp	MTB	164.29035	178.75	29,366.90	0.08%	3.02%	0.00%	11.88%	0.01%
Xcel Energy Inc	XEL	574.55269	70.79	40,672.58		3.22%			
Fifth Third Bancorp	FITB	668.09892	39.2	26,189.48		3.78%			

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outstg	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Gilead Sciences Inc	GILD	1245.16279	112.05	139,520.49		2.82%		21.66%	
Hasbro Inc	HAS	139.53131	61.49	8,579.78	0.02%	4.55%	0.00%	6.73%	0.00%
Huntington Bancshares Inc/OH	HBAN	1460.75396	15.01	21,925.92	0.06%	4.13%	0.00%	12.50%	0.01%
Welltower Inc	WELL	641.30806	153.21	98,254.81	0.28%	1.75%	0.00%	16.50%	0.05%
Biogen Inc	BIIB	146.37494	136.84	20,029.95					
Northern Trust Corp	NTRS	194.97161	98.65	19,233.95	0.06%	3.04%	0.00%	8.91%	0.00%
Packaging Corp of America	PKG	89.92812	198.02	17,807.57		2.52%			
Paychex Inc	PAYX	360.19067	154.28	55,570.22	0.16%	2.54%	0.00%	6.24%	0.01%
QUALCOMM Inc	QCOM	1106	153.61	169,892.66	0.49%	2.21%	0.01%	15.26%	0.07%
Ross Stores Inc	ROST	329.9292	127.79	42,161.65	0.12%	1.27%	0.00%	6.48%	0.01%
IDEXX Laboratories Inc	IDXX	81.03904	419.95	34,032.34	0.10%			12.27%	0.01%
Starbucks Corp	SBUX	1135.9	98.09	111,420.43	0.32%	2.49%	0.01%	9.20%	0.03%
KeyCorp	KEY	1095.71722	15.99	17,520.52	0.05%	5.13%	0.00%	18.11%	0.01%
Fox Corp	FOXA	217.84683	56.6	12,330.13	0.04%	0.95%	0.00%	8.98%	0.00%
Fox Corp	FOX	235.58103	52.71	12,417.48	0.04%	1.02%	0.00%	8.98%	0.00%
State Street Corp	STT	288.4691	88.77	25,607.40	0.07%	3.42%	0.00%	10.32%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	439.94482	18.96	8,341.35	0.02%			18.95%	0.00%
US Bancorp	USB	1558.01053	42.22	65,779.20	0.19%	4.74%	0.01%	9.30%	0.02%
A O Smith Corp	AOS	117.65899	65.36	7,690.19		2.08%			
Gen Digital Inc	GEN	616.30137	26.54	16,356.64	0.05%	1.88%	0.00%	11.23%	0.01%
T Rowe Price Group Inc	TROW	222.24239	91.87	20,417.41		5.53%			
Waste Management Inc	WM	402.11544	231.51	93,093.75	0.27%	1.43%	0.00%	10.93%	0.03%
Constellation Brands Inc	STZ	180.70456	183.52	33,162.90	0.10%	2.20%	0.00%	8.23%	0.01%
Invesco Ltd	IVZ	447.41359	15.17	6,787.26	0.02%	5.41%	0.00%	12.05%	0.00%
Intuit Inc	INTU	279.562	613.99	171,648.27	0.49%	0.68%	0.00%	13.97%	0.07%
Morgan Stanley	MS	1612.85559	116.67	188,171.86	0.54%	3.17%	0.02%	11.82%	0.06%
Microchip Technology Inc	MCHP	537.81897	48.41	26,035.82		3.76%		-33.30%	
Crowdstrike Holdings Inc	CRWD	247.87342	352.58	87,395.21				24.67%	
Chubb Ltd	CB	400.41208	301.99	120,920.44	0.35%	1.21%	0.00%	3.77%	0.01%
Hologic Inc	HOLX	225.72311	61.77	13,942.92	0.04%			9.04%	0.00%
Citizens Financial Group Inc	CFG	437.13389	40.97	17,909.38		4.10%		21.23%	
Jabil Inc	JBL	109.17853	136.07	14,855.92	0.04%	0.24%	0.00%	12.83%	0.01%
O'Reilly Automotive Inc	ORLY	57.24051	1432.58	82,001.61	0.24%			10.30%	0.02%
Allstate Corp/The	ALL	265.02605	207.07	54,878.94	0.16%	1.93%	0.00%	12.65%	0.02%
Equity Residential	EQR	379.70523	71.58	27,179.30	0.08%	3.87%	0.00%	4.03%	0.00%
Keurig Dr Pepper Inc	KDP	1356.75088	34.22	46,428.02	0.13%	2.69%	0.00%	6.20%	0.01%
Host Hotels & Resorts Inc	HST	699.10684	14.21	9,934.31		5.63%		-0.80%	
Incyte Corp	INCY	193.52435	60.55	11,717.90					
Simon Property Group Inc	SPG	326.24342	166.08	54,182.51	0.16%	5.06%	0.01%	1.29%	0.00%
Eastman Chemical Co	EMN	115.45991	88.11	10,173.17	0.03%	3.77%	0.00%	10.17%	0.00%
AvalonBay Communities Inc	AVB	142.25478	214.62	30,530.72	0.09%	3.26%	0.00%	5.26%	0.00%
Prudential Financial Inc	PRU	354.42709	111.68	39,582.42	0.11%	4.84%	0.01%	7.89%	0.01%
United Parcel Service Inc	UPS	733.48188	109.99	80,675.67	0.23%	5.96%	0.01%	7.91%	0.02%
Walgreens Boots Alliance Inc	WBA	864.73521	11.17	9,659.09				-21.88%	
STERIS PLC	STE	98.25079	226.65	22,268.54		1.01%			
McKesson Corp	MCK	125.32638	672.99	84,343.40	0.24%	0.42%	0.00%	13.47%	0.03%
Lockheed Martin Corp	LMT	234.57305	446.71	104,786.13	0.30%	2.95%	0.01%	11.65%	0.04%
Cencora Inc	COR	193.71259	278.09	53,869.53	0.16%	0.79%	0.00%	9.83%	0.02%
Capital One Financial Corp	COF	381.47946	179.3	68,399.27	0.20%	1.34%	0.00%	14.58%	0.03%
The Campbell's Company	CPB	298.18187	39.92	11,903.42	0.03%	3.91%	0.00%	2.22%	0.00%
Waters Corp	WAT	59.41094	368.57	21,897.09	0.06%			7.42%	0.00%
Nordson Corp	NDSN	56.91174	201.72	11,480.24		1.55%			
Dollar Tree Inc	DLTR	215.08301	75.07	16,146.28	0.05%			7.94%	0.00%
Darden Restaurants Inc	DRI	117.14679	207.76	24,338.42	0.07%	2.70%	0.00%	9.10%	0.01%
Evergy Inc	EVRG	229.74594	68.95	15,840.98	0.05%	3.87%	0.00%	5.71%	0.00%
Match Group Inc	MTCH	250.42913	31.2	7,813.39		2.44%			
NVR Inc	NVR	2.96901	7244.39	21,508.67	0.06%			6.01%	0.00%
NetApp Inc	NTAP	203.41152	87.84	17,867.67	0.05%	2.37%	0.00%	8.16%	0.00%
Old Dominion Freight Line Inc	ODFL	212.54508	165.45	35,165.58	0.10%	0.68%	0.00%	9.27%	0.01%
DaVita Inc	DVA	80	152.97	12,237.60	0.04%			10.03%	0.00%
Hartford Insurance Group Inc/The	HIG	285.38699	123.73	35,310.93	0.10%	1.68%	0.00%	8.76%	0.01%
Iron Mountain Inc	IRM	293.74091	86.04	25,273.47		3.65%			
Estee Lauder Cos Inc/The	EL	234.17342	66	15,455.45	0.04%	2.12%	0.00%	8.85%	0.00%
Cadence Design Systems Inc	CDNS	274.3136	254.33	69,766.18	0.20%			14.79%	0.03%
Tyler Technologies Inc	TYL	43.10602	581.39	25,061.41					
Universal Health Services Inc	UHS	57.7512	187.9	10,851.45	0.03%	0.43%	0.00%	11.19%	0.00%
Skyworks Solutions Inc	SWKS	153.57483	64.63	9,925.54		4.33%		-9.02%	
Quest Diagnostics Inc	DGX	110.97807	169.2	18,777.49	0.05%	1.89%	0.00%	9.07%	0.00%
Rockwell Automation Inc	ROK	113.07295	258.38	29,215.79	0.08%	2.03%	0.00%	12.57%	0.01%
Kraft Heinz Co/The	KHC	1193.39837	30.43	36,315.11		5.26%		-3.61%	
American Tower Corp	AMT	467.45726	217.6	101,718.70		3.13%		23.12%	
Regeneron Pharmaceuticals Inc	REGN	107.50754	634.23	68,184.51	0.20%	0.56%	0.00%	2.86%	0.01%
Amazon.com Inc	AMZN	10597.72935	190.26	2,016,323.99	5.80%			13.61%	0.79%
Jack Henry & Associates Inc	JKHY	72.89767	182.6	13,311.11	0.04%	1.27%	0.00%	9.25%	0.00%
Ralph Lauren Corp	RL	39.88294	220.74	8,803.76	0.03%	1.49%	0.00%	13.79%	0.00%
BXP Inc	BXP	158.2096	67.19	10,630.10	0.03%	5.83%	0.00%	1.55%	0.00%
Amphenol Corp	APH	1211.78331	65.59	79,480.87	0.23%	1.01%	0.00%	15.74%	0.04%
Howmet Aerospace Inc	HWM	405.02252	129.73	52,543.57	0.15%	0.31%	0.00%	12.69%	0.02%
Valero Energy Corp	VLO	314.46067	132.07	41,530.82		3.42%			
Synopsys Inc	SNPS	154.62008	428.85	66,308.82	0.19%			13.35%	0.03%
CH Robinson Worldwide Inc	CHRW	118.25755	102.4	12,109.57	0.03%	2.42%	0.00%	16.60%	0.01%
Accenture PLC	ACN	625.47994	312.04	195,174.76	0.56%	1.90%	0.01%	7.12%	0.04%
TransDigm Group Inc	TDG	56.08459	1383.29	77,581.25	0.22%			13.51%	0.03%
Yum! Brands Inc	YUM	279.10194	157.36	43,919.48	0.13%	1.80%	0.00%	10.30%	0.01%
Prologis Inc	PLD	926.175	111.79	103,537.10	0.30%	3.61%	0.01%	6.63%	0.02%
FirstEnergy Corp	FE	576.69742	40.42	23,310.11	0.07%	4.40%	0.00%	3.61%	0.00%
VeriSign Inc	VRSN	94.6	253.87	24,016.10					
Quanta Services Inc	PWR	148.19832	254.18	37,669.05	0.11%	0.16%	0.00%	13.20%	0.01%
Henry Schein Inc	HSIC	124.17678	68.49	8,504.87	0.02%			5.92%	0.00%
Ameren Corp	AEE	270.15767	100.4	27,123.83		2.83%			
ANSYS Inc	ANSS	87.65178	316.56	27,747.05					
FactSet Research Systems Inc	FDS	38.03005	454.64	17,289.98		0.92%			
NVIDIA Corp	NVDA	24400	108.38	2,644,472.00		0.04%		31.31%	
Cognizant Technology Solutions Corp	CTSH	494.61551	76.5	37,838.09	0.11%	1.62%	0.00%	6.14%	0.01%
Intuitive Surgical Inc	ISRG	358.27457	495.27	177,442.65	0.51%			16.58%	0.08%

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Name	Ticker	Shares Outstg	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Take-Two Interactive Software Inc	TTWO	176.49571	207.25	36,578.74				60.65%	
Republic Services Inc	RSG	312.28495	242.16	75,622.92	0.22%	0.96%	0.00%	8.71%	0.02%
eBay Inc	EBAY	466	67.73	31,562.18	0.09%	1.71%	0.00%	7.84%	0.01%
Goldman Sachs Group Inc/The	GS	310.79039	546.29	169,781.68	0.49%	2.20%	0.01%	9.26%	0.05%
SBA Communications Corp	SBAC	107.61524	220.01	23,676.43	0.07%	2.02%	0.00%	7.17%	0.00%
Sempra	SRE	651.91337	71.36	46,520.54	0.13%	3.62%	0.00%	7.02%	0.01%
Moody's Corp	MCO	179.88933	465.69	83,772.66		0.81%			
ON Semiconductor Corp	ON	421.42113	40.69	17,147.63				-0.17%	
Booking Holdings Inc	BKNG	32.8152	4606.91	151,176.67	0.44%	0.83%	0.00%	15.92%	0.07%
F5 Inc	FFIV	57.65226	266.27	15,351.07	0.04%			7.07%	0.00%
Akamai Technologies Inc	AKAM	150.38748	80.5	12,106.19					
Charles River Laboratories International Inc	CRL	51.14161	150.52	7,697.84	0.02%			3.82%	0.00%
MarketAxess Holdings Inc	MKTX	37.69322	216.35	8,154.93	0.02%	1.41%	0.00%	1.36%	0.00%
Devon Energy Corp	DVN	649	37.4	24,272.60		2.57%		-5.51%	
Bio-Techne Corp	TECH	158.08768	58.63	9,268.68		0.55%			
Alphabet Inc	GOOGL	5833	154.64	902,015.12	2.60%	0.52%	0.01%	12.25%	0.32%
Allegion plc	ALLE	86.29035	130.46	11,257.44	0.03%	1.56%	0.00%	4.12%	0.00%
Netflix Inc	NFLX	427.7571	932.53	398,896.33				22.93%	
Agilent Technologies Inc	A	285.10272	116.732	33,280.61	0.10%	0.85%	0.00%	8.80%	0.01%
Warner Bros Discovery Inc	WBD	2454.76434	10.73	26,339.62				41.11%	
Trimble Inc	TRMB	245.79205	65.65	16,136.25					
Elevance Health Inc	ELV	226.38693	434.96	98,469.26	0.28%	1.57%	0.00%	9.93%	0.03%
CME Group Inc	CME	360.37957	265.29	95,605.10	0.28%	1.88%	0.01%	3.60%	0.01%
Juniper Networks Inc	JNPR	333.18976	36.19	12,058.14	0.03%	2.43%	0.00%	12.36%	0.00%
DTE Energy Co	DTE	207.51775	138.27	28,693.48	0.08%	3.15%	0.00%	5.80%	0.00%
Nasdaq Inc	NDAQ	575.14532	75.86	43,630.52	0.13%	1.27%	0.00%	13.47%	0.02%
Philip Morris International Inc	PM	1556.48821	158.73	247,061.37	0.71%	3.40%	0.02%	10.11%	0.07%
Ingersoll Rand Inc	IR	403.08325	80.03	32,258.75		0.10%			
Salesforce Inc	CRM	961	268.36	257,893.96	0.74%	0.62%	0.00%	12.53%	0.09%
Roper Technologies Inc	ROP	107.38521	589.58	63,312.17		0.56%			
Huntington Ingalls Industries Inc	HII	39.23557	204.04	8,005.63	0.02%	2.65%	0.00%	13.85%	0.00%
MetLife Inc	MET	681.22803	80.29	54,695.80	0.16%	2.72%	0.00%	12.81%	0.02%
Tapestry Inc	TPR	207.01548	70.41	14,575.96	0.04%	1.99%	0.00%	9.55%	0.00%
CSX Corp	CSX	1884.74538	29.43	55,468.06	0.16%	1.77%	0.00%	8.69%	0.01%
Edwards Lifesciences Corp	EW	587.8649	72.48	42,608.45					
Ameriprise Financial Inc	AMP	95.81396	484.11	46,384.50	0.13%	1.22%	0.00%	11.93%	0.02%
Zebra Technologies Corp	ZBRA	51.14332	282.56	14,451.06					
Zimmer Biomet Holdings Inc	ZBH	199.06316	113.18	22,529.97		0.85%			
Camden Property Trust	CPT	108.79919	122.3	13,306.14	0.04%	3.43%	0.00%	1.25%	0.00%
CBRE Group Inc	CBRE	300.03748	130.78	39,238.90					
Mastercard Inc	MA	904.88952	548.12	495,988.04	1.43%	0.55%	0.01%	13.27%	0.19%
CarMax Inc	KMX	153.79997	77.92	11,984.09	0.03%			16.70%	0.01%
Intercontinental Exchange Inc	ICE	574.56486	172.5	99,112.44	0.29%	1.11%	0.00%	16.02%	0.05%
Fidelity National Information Services Inc	FIS	529.69159	74.68	39,557.37	0.11%	2.14%	0.00%	9.27%	0.01%
Smurfit WestRock PLC	SW	521.97622	45.06	23,520.25		3.82%		63.58%	
Chipotle Mexican Grill Inc	CMG	1355.337	50.21	68,051.47	0.20%			19.68%	0.04%
Wynn Resorts Ltd	WYNN	106.16733	83.5	8,864.97	0.03%	1.20%	0.00%	8.30%	0.00%
Live Nation Entertainment Inc	LYV	233.40116	130.58	30,477.52	0.09%			12.10%	0.01%
Assurant Inc	AIZ	50.79192	209.75	10,653.61		1.53%			
NRG Energy Inc	NRG	203.66697	95.46	19,442.05		1.84%			
Monster Beverage Corp	MNST	973.1589	58.52	56,949.26	0.16%			14.23%	0.02%
Regions Financial Corp	RF	905.46507	21.73	19,675.76	0.06%	4.60%	0.00%	5.90%	0.00%
Baker Hughes Co	BKR	990.34958	43.95	43,525.86		2.09%			
Mosaic Co/The	MOS	316.93923	27.01	8,560.53		3.26%		-8.84%	
Expedia Group Inc	EXPE	123.33362	168.1	20,732.38	0.06%	0.95%	0.00%	19.43%	0.01%
CF Industries Holdings Inc	CF	166.4672	78.15	13,009.41		2.56%		-6.30%	
APA Corp	APA	364.06432	21.02	7,652.63		4.76%		-13.72%	
Leidos Holdings Inc	LDOS	128.21387	134.94	17,301.18	0.05%	1.19%	0.00%	7.40%	0.00%
Alphabet Inc	GOOG	5497	156.23	858,796.31	2.47%	0.51%	0.01%	12.25%	0.30%
TKO Group Holdings Inc	TKO	81.55382	152.81	12,462.24		0.99%			
First Solar Inc	FSLR	107.06211	126.43	13,535.86				41.85%	
Discover Financial Services	DFS	251.60413	170.7	42,948.82		1.64%		-0.84%	
Visa Inc	V	1723.36235	350.46	603,969.57	1.74%	0.67%	0.01%	12.19%	0.21%
Mid-America Apartment Communities Inc	MAA	116.90178	167.58	19,590.40	0.06%	3.62%	0.00%	2.74%	0.00%
Xylem Inc/NY	XYL	243.34947	119.46	29,070.53		1.34%			
Marathon Petroleum Corp	MPC	311.53136	145.69	45,387.00		2.50%			
Tractor Supply Co	TSCO	531.61539	55.1	29,292.01	0.08%	1.67%	0.00%	9.11%	0.01%
Advanced Micro Devices Inc	AMD	1616.29752	102.74	166,058.41				23.60%	
ResMed Inc	RMD	146.86691	223.85	32,876.16	0.09%	0.95%	0.00%	14.08%	0.01%
Mettler-Toledo International Inc	MTD	20.84095	1180.91	24,611.29	0.07%			9.24%	0.01%
VICI Properties Inc	VICI	1056.70255	32.62	34,469.64	0.10%	5.30%	0.01%	2.59%	0.00%
Copart Inc	CPRT	966.09296	56.59	54,671.20					
Jacobs Solutions Inc	J	122.54367	120.89	14,814.30	0.04%	1.06%	0.00%	12.45%	0.01%
Albemarle Corp	ALB	117.65057	72.02	8,473.19		2.25%		79.84%	
Fortinet Inc	FTNT	768.97406	96.26	74,021.44	0.21%			9.01%	0.02%
Moderna Inc	MRNA	386.6226	28.35	10,960.75					
Essex Property Trust Inc	ESS	64.32558	306.57	19,720.29	0.06%	3.35%	0.00%	3.33%	0.00%
CoStar Group Inc	CSGP	421.76275	79.23	33,416.26					
Realty Income Corp	O	891.76916	57.7415	51,492.09		5.58%			
Westinghouse Air Brake Technologies Corp	WAB	170.84815	181.35	30,983.31	0.09%	0.55%	0.00%	15.34%	0.01%
Palantir Technologies Inc	PLTR	2248.95083	84.4	189,811.45				31.39%	
Pool Corp	POOL	37.7182	318.35	12,007.59	0.03%	1.51%	0.00%	8.77%	0.00%
Western Digital Corp	WDC	347.8239	40.43	14,062.52				189.78%	
PepsiCo Inc	PEP	1371.31157	149.94	205,614.46	0.59%	3.61%	0.02%	5.01%	0.03%
TE Connectivity PLC	TEL	298.35318	141.32	42,163.27	0.12%	2.01%	0.00%	7.32%	0.01%
Diamondback Energy Inc	FANG	289.4409	159.88	46,275.81		2.50%		-7.45%	
Palo Alto Networks Inc	PANW	662.1	170.64	112,980.74	0.33%			13.48%	0.04%
ServiceNow Inc	NOW	207.19939	796.14	164,959.72					
Church & Dwight Co Inc	CHD	246.109	110.09	27,094.14		1.07%			
Federal Realty Investment Trust	FRT	85.78007	96.72	8,296.65	0.02%	4.55%	0.00%	4.52%	0.00%
MGM Resorts International	MGM	282.95059	29.64	8,386.66	0.02%			17.73%	0.00%
American Electric Power Co Inc	AEP	533.98769	109.27	58,348.83	0.17%	3.40%	0.01%	5.15%	0.01%
Invitation Homes Inc	INVH	612.68959	34.85	21,352.23	0.06%	3.33%	0.00%	3.76%	0.00%

Name	Ticker	[4] Shares Outstg	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
PTC Inc	PTC	120.32354	154.95	18,644.13	0.05%			16.78%	0.01%
JB Hunt Transport Services Inc	JBHT	100.00821	147.95	14,796.21	0.04%	1.19%	0.00%	16.22%	0.01%
Lam Research Corp	LRCX	1283.662	72.7	93,322.23	0.27%	1.27%	0.00%	16.87%	0.05%
Mohawk Industries Inc	MHK	62.58723	114.18	7,146.21	0.02%			8.38%	0.00%
GE HealthCare Technologies Inc	GEHC	457.29831	80.71	36,908.55	0.11%	0.17%	0.00%	9.53%	0.01%
Pentair PLC	PNR	164.96968	87.48	14,431.55	0.04%	1.14%	0.00%	9.27%	0.00%
Vertex Pharmaceuticals Inc	VRTX	256.78987	484.82	124,496.86				305.00%	
Amcor PLC	AMCR	1445.34321	9.7	14,019.83	0.04%	5.26%	0.00%	7.10%	0.00%
Meta Platforms Inc	META	2189.89815	576.36	1,262,169.70	3.63%	0.36%	0.01%	13.81%	0.50%
T-Mobile US Inc	TMUS	1141.74495	266.71	304,514.80		1.32%			
United Rentals Inc	URI	65.33209	626.7	40,943.62	0.12%	1.14%	0.00%	9.68%	0.01%
Alexandria Real Estate Equities Inc	ARE	173.09176	92.51	16,012.72	0.05%	5.71%	0.00%	2.61%	0.00%
Honeywell International Inc	HON	648.76775	211.75	137,376.57		2.13%			
Delta Air Lines Inc	DAL	645.96201	43.6	28,163.94	0.08%	1.38%	0.00%	11.42%	0.01%
United Airlines Holdings Inc	UAL	328.80309	69.05	22,703.85	0.07%			12.86%	0.01%
Seagate Technology Holdings PLC	STX	211.70739	84.95	17,984.54		3.39%			
News Corp	NWS	189.34085	30.37	5,750.28		0.66%			
Centene Corp	CNC	496.06005	60.71	30,115.81	0.09%			7.97%	0.01%
Apollo Global Management Inc	APO	570.48047	136.94	78,121.60	0.22%	1.35%	0.00%	13.50%	0.03%
Martin Marietta Materials Inc	MLM	60.97415	478.13	29,153.57		0.66%		-11.04%	
Teradyne Inc	TER	161.53887	82.6	13,343.11	0.04%	0.58%	0.00%	6.69%	0.00%
PayPal Holdings Inc	PYPL	989.24245	65.25	64,548.07	0.19%			12.44%	0.02%
Tesla Inc	TSLA	3216.51704	259.16	833,592.56					
Blackrock Inc	BLK	155.25344	946.48	146,944.28		2.20%			
KKR & Co Inc	KKR	888.25053	115.61	102,690.64		0.61%			
Arch Capital Group Ltd	ACGL	375.71602	96.18	36,136.37	0.10%			2.86%	0.00%
Dow Inc	DOW	705.76446	34.92	24,645.29		8.02%		32.49%	
Everest Group Ltd	EG	42.9341	363.33	15,599.25		2.20%		28.71%	
Teledyne Technologies Inc	TDY	46.8373	497.71	23,311.39	0.07%			9.78%	0.01%
Domino's Pizza Inc	DPZ	34.29704	459.45	15,757.78	0.05%	1.51%	0.00%	9.24%	0.00%
GE Vernova Inc	GEV	273.34557	305.28	83,446.94		0.33%		97.07%	
News Corp	NWSA	378.05509	27.22	10,290.66		0.73%			
Exelon Corp	EXC	1009.53563	46.08	46,519.40	0.13%	3.47%	0.00%	8.40%	0.01%
Global Payments Inc	GPN	245.87628	97.92	24,076.21	0.07%	1.02%	0.00%	9.66%	0.01%
Crown Castle Inc	CCI	435.43378	104.23	45,385.26		6.01%		33.10%	
Align Technology Inc	ALGN	73.21033	158.86	11,630.19	0.03%			10.64%	0.00%
Kenvue Inc	KVUE	1911.24072	23.98	45,831.55		3.42%		34.17%	
Targa Resources Corp	TRGP	217.58533	200.47	43,619.33		1.50%			
Bunge Global SA	BG	133.96805	76.42	10,237.84	0.03%	3.56%	0.00%	3.46%	0.00%
LKQ Corp	LKQ	258.55312	42.54	10,998.85		2.82%			
Deckers Outdoor Corp	DECK	151.77364	111.81	16,969.81				22.63%	
Workday Inc	WDAY	215	233.53	50,208.95					
Zoetis Inc	ZTS	447.79192	164.65	73,728.94	0.21%	1.21%	0.00%	7.96%	0.02%
Equinix Inc	EQIX	97.33201	815.35	79,359.65		2.30%			
Digital Realty Trust Inc	DLR	336.64425	143.29	48,237.75		3.41%			
Molina Healthcare Inc	MOH	54.69986	329.39	18,017.59	0.05%			9.45%	0.00%
Las Vegas Sands Corp	LVS	715.93467	38.63	27,656.56	0.08%	2.59%	0.00%	7.35%	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, 2025
[5] Bloomberg Professional as of March 31, 2025
[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, 2025
[9] Equals [7] x [8]
[10] Value Line, as of March 31, 2025
[11] Equals [7] x [10]

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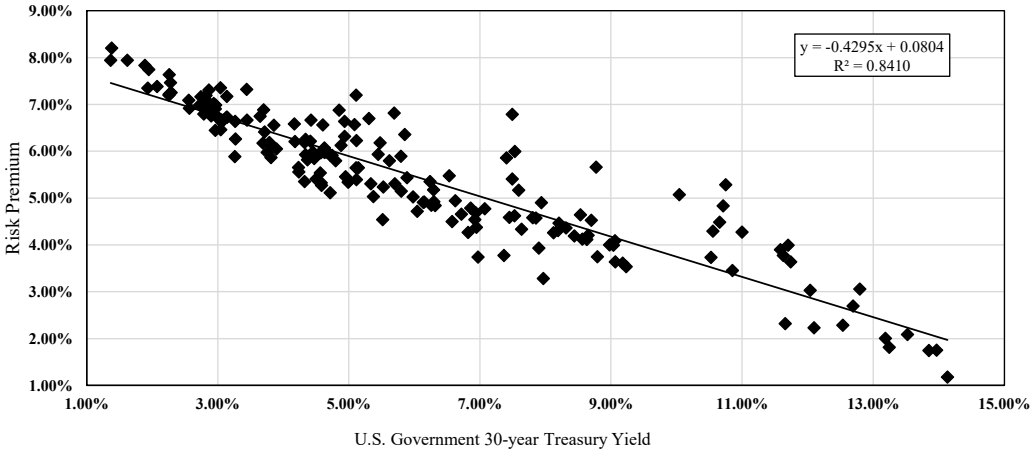


SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9170511
R Square	0.8409827
Adjusted R Square	0.8400943
Standard Error	0.0056936
Observations	181

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03069	0.03069	946.66349	0.00000
Residual	179	0.00580	0.00003		
Total	180	0.03649			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0804	0.00	85.21	0.0000	0.0785	0.0823	0.0785	0.0823
U.S. Govt. 30-year Treasury	(0.4295)	0.01	(30.77)	0.0000	(0.4571)	(0.4020)	(0.4571)	(0.4020)

	[7] U.S. Govt. 30-year Treasury [7]	[8] Risk Premium [8]	[9] ROE [9]
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.61%	6.06%	10.67%
Blue Chip Near-Term Projected Forecast (Q3 2025 - Q3 2026) [5]	4.52%	6.10%	10.62%
Blue Chip Long-Term Projected Forecast (2026-2030) [6]	4.30%	6.19%	10.49%
AVERAGE			10.59%

Notes:
[1] Source: Regulatory Research Associates, rate cases through March 31, 2025
[2] Source: 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] Source: S&P Capital IQ Pro, 30-day average as of March 31, 2025
[5] Source: Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.080389 + (-0.429537 x Column [7])
[9] 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%
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%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
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%
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%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
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%
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	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.26%	7.21%
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	9.50%	3.05%	6.45%
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	9.67%	3.81%	5.86%
2023.3	9.79%	4.23%	5.55%
2023.4	9.85%	4.58%	5.27%
2024.1	9.67%	4.32%	5.35%
2024.2	9.90%	4.58%	5.32%
2024.3	9.88%	4.23%	5.65%
2024.4	9.90%	4.50%	5.40%
2025.1	9.83%	4.72%	5.11%
AVERAGE	11.48%	6.04%	5.44%
MEDIAN	11.00%	5.14%	5.64%

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	$ 2.03	$ 63.18	3.21%	3.32%	3.44%	6.00%	6.81%	6.70%	6.50%	9.82%	9.95%
Ameren Corporation	AEE	$ 2.84	$ 98.76	2.88%	2.97%	3.08%	6.50%	6.88%	6.70%	6.69%	9.66%	9.78%
American Electric Power Company, Inc.	AEP	$ 3.72	$ 105.20	3.54%	3.65%	3.79%	6.50%	6.69%	6.30%	6.50%	10.15%	10.29%
Avista Corporation	AVA	$ 1.96	$ 39.32	4.98%	5.13%	5.32%	5.50%	5.88%	6.10%	5.83%	10.96%	11.15%
Dominion Resources, Inc.	D	$ 2.67	$ 55.10	4.85%	5.09%	5.28%	3.50%	13.49%	13.60%	10.20%	15.29%	15.48%
DTE Energy Company	DTE	$ 4.36	$ 132.97	3.28%	3.39%	3.51%	4.50%	7.87%	7.60%	6.66%	10.05%	10.17%
Duke Energy Corporation	DUK	$ 4.18	$ 117.26	3.56%	3.68%	3.81%	6.00%	6.32%	6.30%	6.21%	9.88%	10.02%
Entergy Corporation	ETR	$ 2.40	$ 84.52	2.84%	2.94%	3.05%	3.00%	8.88%	9.50%	7.13%	10.07%	10.18%
Evergy, Inc.	EVRG	$ 2.67	$ 67.12	3.98%	4.10%	4.26%	7.50%	5.72%	5.70%	6.31%	10.41%	10.56%
IDACORP, Inc.	IDA	$ 3.44	$ 114.74	3.00%	3.11%	3.23%	6.00%	8.23%	8.50%	7.58%	10.69%	10.81%
NextEra Energy, Inc.	NEE	$ 2.27	$ 70.92	3.20%	3.32%	3.44%	8.50%	7.11%	7.80%	7.80%	11.12%	11.25%
NorthWestern Corporation	NWE	$ 2.64	$ 54.98	4.80%	4.93%	5.12%	4.50%	5.94%	6.10%	5.51%	10.45%	10.63%
OGE Energy Corporation	OGE	$ 1.69	$ 44.89	3.75%	3.87%	4.01%	6.50%	5.92%	6.10%	6.17%	10.04%	10.19%
Pinnacle West Capital Corporation	PNW	$ 3.58	$ 92.41	3.87%	3.95%	4.10%	4.00%	5.55%	2.10%	3.88%	7.83%	7.98%
TXNM Energy	TXNM	$ 1.63	$ 52.10	3.13%	3.20%	3.32%	4.00%	6.55%	3.00%	4.52%	7.71%	7.83%
Portland General Electric Company	POR	$ 2.00	$ 43.72	4.57%	4.69%	4.87%	5.50%	6.54%	3.40%	5.15%	9.84%	10.01%
PPL Corporation	PPL	$ 1.09	$ 34.58	3.15%	3.27%	3.39%	7.50%	7.27%	6.80%	7.19%	10.46%	10.58%
Southern Company	SO	$ 2.88	$ 89.46	3.22%	3.32%	3.45%	6.50%	6.33%	6.50%	6.44%	9.77%	9.89%
Xcel Energy Inc.	XEL	$ 2.28	$ 69.25	3.29%	3.41%	3.53%	6.50%	7.26%	6.90%	6.89%	10.29%	10.42%
Mean											10.24%	10.38%
Median											10.07%	10.19%
Flotation Cost Adjustment (Mean)												0.14% [21]
Flotation Cost Adjustment (Median)												0.12% [22]

Notes:
[1] - [4] Sources: 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, 2025
[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)

2025-2029 CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT
($ Millions)

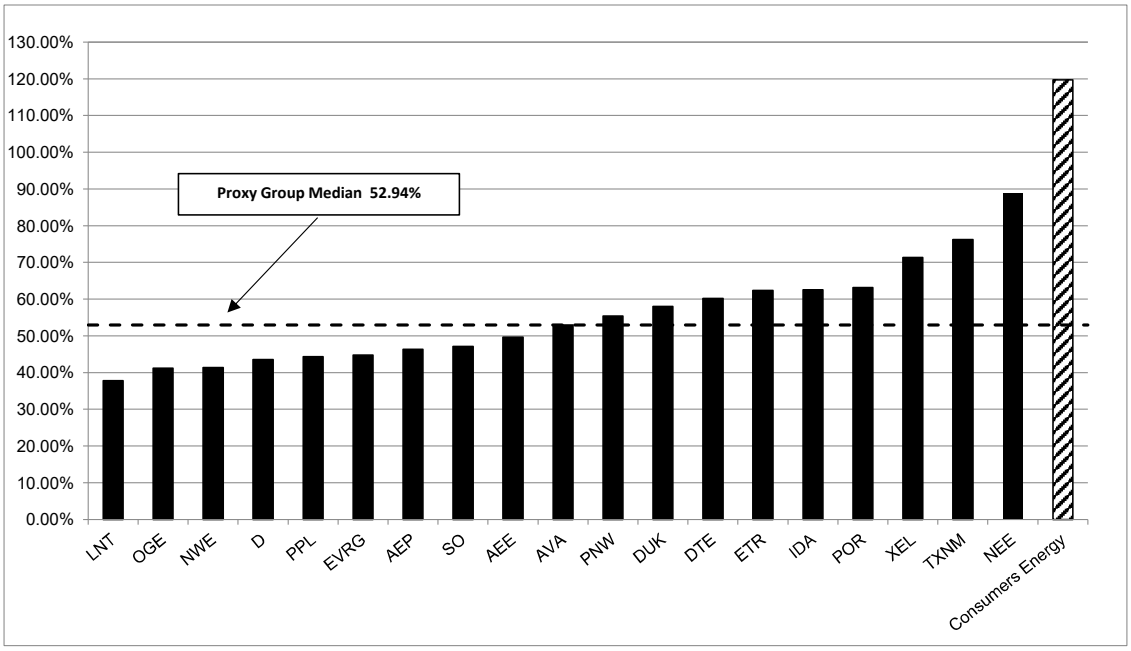
		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2024	2025	2026	2027	2028	2029	2025-29 Cap. Ex. / 2024 Net Plant
Alliant Energy Corporation	LNT							
Capital Spending per Share			$5.60	$5.60	$5.50	$5.40	$5.40	
Common Shares Outstanding			256.70	257.00	257.00	257.00	257.00	
Capital Expenditures			$1,437.5	$1,439.2	$1,413.5	$1,387.8	$1,387.8	37.78%
Net Plant		$18,701.0						
Ameren Corporation	AEE							
Capital Spending per Share			$12.80	$12.85	$12.93	$13.00	$13.00	
Common Shares Outstanding			272.00	275.00	280.00	285.00	285.00	
Capital Expenditures			$3,481.6	$3,533.8	$3,619.0	$3,705.0	$3,705.0	49.61%
Net Plant		$36,376.0						
American Electric Power Company, Inc.	AEP							
Capital Spending per Share			$14.10	$14.10	$14.05	$14.00	$14.00	
Common Shares Outstanding			535.00	540.00	545.00	550.00	550.00	
Capital Expenditures			$7,543.5	$7,614.0	$7,657.3	$7,700.0	$7,700.0	46.37%
Net Plant		$82,416.0						
Avista Corporation	AVA							
Capital Spending per Share			$7.20	$7.43	$7.65	$7.65	$7.65	
Common Shares Outstanding			81.00	83.00	85.00	85.00	85.00	
Capital Expenditures			$583.2	$616.3	$650.3	$650.3	$650.3	52.94%
Net Plant		$5,950.0						
D Dominion Resources, Inc.	D							
Capital Spending per Share			$14.50	$15.50	$15.50	$15.50	$15.50	
Common Shares Outstanding			347.00	348.00	351.50	355.00	355.00	
Capital Expenditures			$5,031.5	$5,394.0	$5,448.3	$5,502.5	$5,502.5	43.58%
Net Plant		$61,675.0						
DTE Energy Company	DTE							
Capital Spending per Share			$17.75	$17.95	$18.23	$18.50	$18.50	
Common Shares Outstanding			205.50	205.50	205.75	206.00	206.00	
Capital Expenditures			$3,647.6	$3,688.7	$3,749.8	$3,811.0	$3,811.0	60.19%
Net Plant		$31,081.0						
Duke Energy Corporation	DUK							
Capital Spending per Share			$17.75	$18.00	$18.38	$18.75	$18.75	
Common Shares Outstanding			773.00	774.00	775.50	777.00	777.00	
Capital Expenditures			$13,720.8	$13,932.0	$14,249.8	$14,568.8	$14,568.8	58.03%
Net Plant		$122,425.0						
Entergy Corporation	ETR							
Capital Spending per Share			$12.00	$12.50	$13.25	$14.00	$14.00	
Common Shares Outstanding			435.00	440.00	450.00	460.00	460.00	
Capital Expenditures			$5,220.0	$5,500.0	$5,962.5	$6,440.0	$6,440.0	62.34%
Net Plant		$47,423.0						
Evergy, Inc.	EVRG							
Capital Spending per Share			$9.30	$9.35	$9.43	$9.50	$9.50	
Common Shares Outstanding			230.00	230.00	230.00	230.00	230.00	
Capital Expenditures			$2,139.0	$2,150.5	$2,167.8	$2,185.0	$2,185.0	44.74%
Net Plant		$24,200.0						
IDACORP, Inc.	IDA							
Capital Spending per Share			$16.60	$15.00	$13.40	$13.40	$13.40	
Common Shares Outstanding			54.00	55.00	56.00	56.00	56.00	
Capital Expenditures			$896.4	$825.0	$750.4	$750.4	$750.4	62.56%
Net Plant		$6,350.0						
NextEra Energy, Inc.	NEE							
Capital Spending per Share			$11.00	$11.00	$11.50	$12.00	$12.00	
Common Shares Outstanding			2065.00	2100.00	2150.00	2200.00	2200.00	
Capital Expenditures			$22,715.0	$23,100.0	$24,725.0	$26,400.0	$26,400.0	88.83%
Net Plant		$138,852.0						
NorthWestern Corporation	NWE							
Capital Spending per Share			$8.15	$8.20	$8.25	$8.25	$8.25	
Common Shares Outstanding			62.00	63.00	64.00	64.00	64.00	
Capital Expenditures			$505.3	$516.6	$528.0	$528.0	$528.0	41.36%
Net Plant		$6,300.0						
OGE Energy Corporation	OGE							
Capital Spending per Share			$4.75	$4.75	$4.75	$4.75	$4.75	
Common Shares Outstanding			200.20	200.20	200.20	200.20	200.20	
Capital Expenditures			$951.0	$951.0	$951.0	$951.0	$951.0	41.21%
Net Plant		$11,538.0						
Pinnacle West Capital Corporation	PNW							
Capital Spending per Share			$17.00	$17.10	$17.20	$17.20	$17.20	
Common Shares Outstanding			118.00	121.50	125.00	125.00	125.00	
Capital Expenditures			$2,006.0	$2,077.7	$2,150.0	$2,150.0	$2,150.0	55.37%
Net Plant		$19,025.0						

2025-2029 CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2024	2025	2026	2027	2028	2029	2025-29 Cap. Ex. / 2024 Net Plant
TXNM Energy	TXNM							
Capital Spending per Share			$13.85	$13.68	$13.50	$13.50	$13.50	
Common Shares Outstanding			92.00	93.50	95.00	95.00	95.00	
Capital Expenditures			$1,274.2	$1,278.6	$1,282.5	$1,282.5	$1,282.5	76.19%
Net Plant		$8,400.0						
Portland General Electric Company	POR							
Capital Spending per Share			$11.00	$11.13	$11.25	$11.25	$11.25	
Common Shares Outstanding			110.00	115.00	120.00	120.00	120.00	
Capital Expenditures			$1,210.0	$1,279.4	$1,350.0	$1,350.0	$1,350.0	63.18%
Net Plant		$10,350.0						
PPL Corporation	PPL							
Capital Spending per Share			$3.70	$3.65	$3.83	$4.00	$4.00	
Common Shares Outstanding			737.40	737.50	737.75	738.00	738.00	
Capital Expenditures			$2,728.4	$2,691.9	$2,821.9	$2,952.0	$2,952.0	44.35%
Net Plant		$31,900.0						
Southern Company	SO							
Capital Spending per Share			$8.75	$8.70	$8.60	$8.50	$8.50	
Common Shares Outstanding			1,095.00	1095.00	1095.00	1095.00	1095.00	
Capital Expenditures			$9,581.3	$9,526.5	$9,417.0	$9,307.5	$9,307.5	47.14%
Net Plant		$100,000.0						
Xcel Energy Inc.	XEL							
Capital Spending per Share			$15.00	$14.00	$13.00	$13.00	$13.00	
Common Shares Outstanding			580.00	587.50	595.00	595.00	595.00	
Capital Expenditures			$8,700.0	$8,225.0	$7,735.0	$7,735.0	$7,735.0	71.37%
Net Plant		$56,225.0						
Consumers Energy Company	Consumers Energy							
Capital Expenditures [8]			$2,459	$2,817	$3,110	$2,696	$2,613	119.76%
Net Electric Plant in Service [9]		$ 11,436						
			Consumers Energy CapEx Total (2025-2029)					$13,695
			Consumers Energy CapEx Annual Average					$2,739
			Proxy Group Median					52.9%
			Consumers Energy as % Proxy Group Median					2.26

Notes:
[1] - [6] Value Line dated January 17, 2025, February 7, 2025, and March 7, 2025
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] - [9] Data provided by Consmers Energy.

2025-2029 CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT



	Company		2025-2029
1	Alliant Energy Corporation	LNT	37.78%
2	OGE Energy Corporation	OGE	41.21%
3	NorthWestern Corporation	NWE	41.36%
4	D	D	43.58%
5	PPL Corporation	PPL	44.35%
6	Evergy, Inc.	EVRG	44.74%
7	American Electric Power Company, Inc.	AEP	46.37%
8	Southern Company	SO	47.14%
9	Ameren Corporation	AEE	49.61%
10	Avista Corporation	AVA	52.94%
11	Pinnacle West Capital Corporation	PNW	55.37%
12	Duke Energy Corporation	DUK	58.03%
13	DTE Energy Company	DTE	60.19%
14	Entergy Corporation	ETR	62.34%
15	IDACORP, Inc.	IDA	62.56%
16	Portland General Electric Company	POR	63.18%
17	Xcel Energy Inc.	XEL	71.37%
18	TXNM Energy	TXNM	76.19%
19	NextEra Energy, Inc.	NEE	88.83%
20	Consumers Energy Company	Consumers Energy	119.76%
	Proxy Group Median		52.94%
	Consumers Energy / Proxy Group		2.26

Notes:
Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 27-28, col. [7]

COMPARISON OF CONSUMERS ENERGY AND PROXY GROUP COMPANIES
REGULATORY RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]
						Revenue Stabilization			
Company	Operating Subsidiary	State	Utility Type	Test Year Convention	Revenue Decoupling	Formula-Based Rates	Straight Fixed Variable Rate Design	Overall Revenue Stabilization	Capital Cost Recovery
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Fully Forecast	No	No	No	No	Yes
	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	Yes	No	No	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Southwestern Electric Power Co.	Louisiana	Electric	Historical	Yes	Yes	No	Yes	No
	Indiana Michigan Power Co.	Michigan	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Ohio Power Co.	Ohio	Electric	Partially Forecast	Yes	No	No	Yes	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	Yes
	Appalachian Power Co.	Virginia	Electric	Historical	No	No	No	No	Yes
	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	No
	Avista Corp.	Idaho	Gas	Historical	Yes	No	No	Yes	No
	Avista Corp.	Oregon	Gas	Fully Forecast	Yes	No	No	Yes	No
	Avista Corp.	Washington	Electric	Historical	Yes	No	No	Yes	No
	Avista Corp.	Washington	Gas	Historical	Yes	No	No	Yes	No
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	Fully Forecast	Yes	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	North Carolina	Electric	Historical	No	No	No	No	Yes
	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	Yes
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Historical	Yes	No	No	Yes	No
	Piedmont Natural Gas Co. Inc.	Tennessee	Gas	Historical	Yes	No	No	Yes	Yes
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Fully Forecast	Yes	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	No
	Entergy Louisiana LLC	Louisiana	Electric	Historical	Yes	Yes	No	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Historical	No	Yes	No	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Fully Forecast	Yes	Yes	No	Yes	No

COMPARISON OF CONSUMERS ENERGY AND PROXY GROUP COMPANIES
REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Decoupling	[3] Revenue Stabilization: Formula-Based Rates	[4] Revenue Stabilization: Straight Fixed Variable Rate Design	[5] Overall Revenue Stabilization	[6] Capital Cost Recovery
	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
	Pivotal Utility Holdings Inc.	Florida	Gas	Fully Forecast	No	No	No	No	Yes
	Lone Star Transmission LLC	Texas	Electric	Historical	No	No	No	No	Yes
NorthWestern Corporation	NorthWestern Corporation	Montana	Electric	Historical	No	No	No	No	No
	NorthWestern Corporation	Montana	Gas	Historical	No	No	No	No	No
	NorthWestern Corporation	Nebraska	Gas	Historical	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Electric	Historical	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Gas	Historical	No	No	No	No	No
OGE Energy Corporation	Oklahoma Gas and Electric Company	Arkansas	Electric	Historical	Yes	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
TXNM Energy	Public Service Co. of New Mexico	New Mexico	Electric	Fully Forecast	No	No	No	No	Yes
	Texas-New Mexico Power Co.	Texas	Electric	Historical	No	No	No	No	Yes
Portland General Electric Company	Portland General Electric Co.	Oregon	Electric	Fully Forecast	No	No	No	No	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	Yes	No	Yes	Yes
	Atlanta Gas & Light Co.	Georgia	Gas	Fully Forecast	No	Yes	Yes	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Historical	Yes	Yes	No	Yes	No
	Virginia Natural Gas Inc.	Virginia	Gas	Partially Forecast	Yes	No	No	Yes	Yes
Xcel Energy Inc.	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	No	No	No	No	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	No
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Fully Forecast	No	No	No	No	No
Proxy Group Totals				Fully Forecast 39					
				Partially Forecast 9				Yes 57	Yes 68
				Historical 47				No 38	No 27
				% Forecast 50.53%				% Yes 60.00%	% Yes 71.58%
Consumers Energy Company [7]		Michigan	Electric	Fully Forecast	No	No	No	No	Yes

Notes:
[1] Regulatory Research Associates, effective as of March 31, 2025.
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit. A designation of "Yes" indicates full or partial decoupling.
[3] S&P Capital IQ Pro, Alternative Regulation
[4] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[5] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[6] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. 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".
[7] Data provided by the Company.

Schedule D-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Short-Term Debt Utilization
for the Projected Year Ending April 30, 2027
(in millions)

Case No.: U-21870
Exhibit No.: A-14 (MRB-7)
Schedule: D-6
Page: 1 of 1
Witness: MRBleckman
Date: June 2025

Ending Short-Term Debt

Line No.	(a) Actual Jan-24	(b) Actual Feb-24	(c) Actual Mar-24	(d) Actual Apr-24	(e) Actual May-24	(f) Actual Jun-24	(g) Actual Jul-24	(h) Actual Aug-24	(i) Actual Sep-24	(j) Actual Oct-24	(k) Actual Nov-24	(l) Actual Dec-24
1												
2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 65
3												
4												
5	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
6												
7	$ -	$ 161	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 76	$ 431	$ 478
8												
9												
10	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
11												
12	$ 296	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 83	$ 288	$ 478	$ 483
13												
14												
15	Jan-27	Feb-27	Mar-27	Apr-27								
16												
17	$ 322	$ 274	$ -	$ -								
18												
19	**Test Year 13-Month Avg**			**$ 148**								

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-21870
Exhibit No.: A-15 (EMB-2)
Schedule: E-1
Page: 1 of 1
Witness: EMBreuring
Date: June 2025

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	2025	Fcst	12,521	12,505	11,952	145	37,122	2,094	5.3%	39,216
2	2026	Fcst	12,577	12,430	13,167	146	38,319	2,101	5.2%	40,420
3	Test Year	Fcst	12,599	12,454	13,464	145	38,662	2,051	5.0%	40,713
4	2027	Fcst	12,695	12,406	14,510	144	39,755	2,051	4.9%	41,806
5	2028	Fcst	12,854	12,383	14,948	143	40,329	2,084	4.9%	42,413
6	2029	Fcst	13,013	12,373	16,474	143	42,003	2,010	4.6%	44,013

Bundled Electric Deliveries

	Year		Residential	Commercial	Industrial	Other	Total	Losses & Company Use GWh	Losses & Company Use % of Output	System Output
7	2025	Fcst	12,521	11,594	9,263	145	33,522	2,025	5.7%	35,547
8	2026	Fcst	12,577	11,529	10,501	146	34,752	2,032	5.5%	36,784
9	Test Year	Fcst	12,599	11,554	10,817	145	35,115	1,985	5.3%	37,099
10	2027	Fcst	12,695	11,504	11,885	144	36,228	1,988	5.2%	38,217
11	2028	Fcst	12,854	11,485	12,373	143	36,855	2,023	5.2%	38,878
12	2029	Fcst	13,013	11,467	0 13,907	143	38,530	1,953	4.8%	40,483

Choice Electric Deliveries

	Year		Residential	Commercial	Industrial	Other	Total	Losses & Company Use GWh	Losses & Company Use % of Output	System Output
13	2025	Fcst	-	911	2,689	-	3,600	70	1.9%	3,670
14	2026	Fcst	-	901	2,666	-	3,567	69	1.9%	3,636
15	Test Year	Fcst	-	901	2,647	-	3,548	67	1.8%	3,614
16	2027	Fcst	-	902	2,625	-	3,527	62	1.7%	3,589
17	2028	Fcst	-	898	2,576	-	3,474	61	1.7%	3,535
18	2029	Fcst	-	906	2,567	-	3,473	57	1.6%	3,530

Schedule E-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year Total Company Electric Revenues & Deliveries
May 2026 - April 2027

Case No.: U-21870
Exhibit No.: A-15 (EMB-3)
Schedule: E-2
Page: 1 of 1
Witness: EMBreuring
Date: June 2025

Line No.	Description	(a) 2024 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 / LED	(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	$ 2,433,448	$ -	$ -	$ -	$ -	$ 352	$ (334,072)	$ 530,307	$ -	$ 2,630,035
2	GSG Power Supply (1)	8,624	(8,624)	-	-	-	-	-	-	15,603	15,603
3	Base PSCR	1,957,371	-	-	-	-	317	(297,454)	143,820	-	1,804,054
4	PSCR Factor	59,483	(59,483)	-	-	-	-	-	-	284,114	284,114
5	Total Cycle Billed Tariff Revenue	4,458,926	(68,107)	-	-	-	669	(631,526)	674,127	299,717	4,733,807
	Cycle Billed Surcharge Revenue										
6	Energy Optimization	213,573	-	(213,546)	-	(27)	-	-	-	-	-
7	Renewables	17,500	-	(17,500)	-	-	-	-	-	-	-
8	LIEAF	19,792	-	(19,792)	-	(0)	-	-	-	-	-
9	Power Plant Securization Credit	-	-	-	-	-	-	-	-	-	-
10	Power Plant Securization Charge	34,961	-	(32,946)	-	(2,015)	-	-	-	-	-
11	Karn Securitization Credit	(26,848)		26,848		-	-	-	-	-	-
12	Karn Securitization Surcharge	145,500		(138,933)		(6,567)	-	-	-	-	-
13	Distribution Deferral Surcharge	7,015		(7,015)		-	-	-	-	-	-
14	DR Surcharge	4,510		(4,510)		-	-	-	-	-	-
15	IRM	2,183		(2,183)		-	-	-	-	-	-
16	Other Provisions for Refund	(164,349)	-	164,349	-	-	-	-	-	-	-
17	Total Cycle Billed Surcharge Revenu	253,837	-	(245,229)	-	(8,608)	-	-	-	-	-
	Unbilled Revenue										
18	Base Tariff	30,742	-	-	(31,346)	605	-	-	-	-	-
19	Base PSCR	14,472	-	-	(14,472)	-	-	-	-	-	-
20	PSCR Factor	5,366	(5,366)	-	-	-	-	-	-	-	-
21	Total Unbilled Revenue	50,580	(5,366)	-	(45,818)	605	-	-	-	-	-
22	PSCR Over/Under Recovery	(136,699)	136,699	-	-	-	-	-	-	-	-
23	Total Calendar Revenue	4,626,644	63,226	(245,229)	(45,818)	(8,003)	669	(631,526)	674,127	299,717	4,733,807
24	Miscellaneous Revenue (2) (3) (4)	186,949	(752)	-	(149,398)	223,745	-	-	-	-	260,545
25	Intersystem Sales Revenue	187,217	-	-	(187,217)	-	-	-	24,609	-	24,609
26	Total Operating Revenue	$ 5,000,811	$ 62,474	$ (245,229)	$ (382,433)	$ 215,741	$ 669	$ (631,526)	$ 698,736	$ 299,717	$ 5,018,960
	Revenue Adjustments										
27	Jobwork Revenue	1,663	-	-	-	-	-	-	-	-	1,663
28	Jobwork Expense	(1,278)	-	-	-	-	-	-	-	-	(1,278)
29	Total Revenue Adjustments	385	-	-	-	-	-	-	-	-	385
30	Adjusted Total Operating Revenue	$ 5,001,196	$ 62,474	$ (245,229)	$ (382,433)	$ 215,741	$ 669	$ (631,526)	$ 698,736	$ 299,717	$ 5,019,346
	Electric Deliveries (MWh)										
31	Cycle Billed Bundled Service	32,771,775	-	-	-	2,319,156	82,075	(4,980,197)	-	-	30,192,808
32	Cycle Billed Self-generation	177,359	-	-	-	-	-	(4,058)	-	-	173,301
33	Cycle Billed Electric Choice	3,597,726	-	-	-	-	(12,078)	(33,025)	-	-	3,552,623
34	Intersystem Sales	6,396,630	-	-	(6,396,630)	-	-	-	-	-	-
35	Unbilled Bundled Service	248,222	-	-	(248,222)	42,434	-	(42,434)	-	-	-
36	Unbilled Electric Choice	(15,136)	-	-	15,136		-	-	-	-	-
37	Total Electric Deliveries	43,176,576	-	-	(6,629,716)	2,361,590	69,997	(5,059,714)	-	-	33,918,733

Notes:
(1) GSG Power Supply (ln2, col. i), (EMB-6)
(2) Miscellaneous Revenues (ln24, col. b): 2024 P-521, Page 301.1, Purchased Power Admin Fees
(3) Miscellaneous Revenues (ln24, col.d): Authorized Return on Renewable Energy Assets, FCM (2024 P-521, pg 301.1) removed, and LTILRR customer base tariff revenues (WP-2, ln 19 col. d) removed; Grand Rapids Streetlighting added
(4) Miscellaneous Revenues (ln24, col. e): LTILRR (Laura C) and LEDR (Laura C)

Schedule E-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Deliveries & Customer Counts by Rate Category
(Annual Deliveries in MWh)

Case No.: U-21870
Exhibit No.: A-15 (EMB-4)
Schedule: E-3
Page: 1 of 1
Witness: EMBreuring
Date: June 2025

Line No.	Description	(a) 2024 Avg. No. of Customers	(b) 2024 Annual Deliveries	(c) Test Year Avg. No. of Customers	(d) Test Year Annual Deliveries
	Bundled Residential Service				
1	Standard Service RS	10,787	103,833	10,973	108,263
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)	8,452	97,258	16,879	168,382
7	Summer On-Peak (RSP)	1,614,371	12,042,417	1,628,594	12,230,766
8	Smart Hours (RSH)	24,233	180,314	24,351	177,999
9	Total Bundled Residential	1,657,843	12,423,822	1,680,798	12,685,409
	Bundled Secondary Service				
10	Secondary Energy-only GS	204,356	4,087,646	204,973	4,043,300
11	Secondary Demand GSD	19,910	2,947,769	20,152	2,927,804
12	Secondary GSTU	2,004	91,360	1,891	83,093
13	Total Bundled Secondary	226,270	7,126,774	227,015	7,054,196
	Bundled Primary Service				
14	Primary Energy-only GP	1,362	670,575	1,360	659,010
15	Primary Demand GPD	1,030	7,735,609	855	4,994,897
16	Primary Time-of-Use GPTU	1,433	3,954,047	1,517	4,243,508
17	General Service Primary (EIP)	18	408,336	17	392,565
18	Special Contract (Rate_LED)	-	-	-	-
19	Total Bundled Primary	3,843	12,768,568	3,748	10,289,980
	Bundled Street Lighting Service				
20	Unmetered Lighting GUL	3,863	56,621	-	-
21	Metered Lighting GML	387	4,399	399	10,777
22	Unmetered GU	460	94,740	465	97,806
23	Unmetered Lighting GU-LED	841	21,964	-	-
24	Universal Unmetered Lighting UUL			4,696	54,640
25	Total Bundled Street Lighting	5,551	177,724	5,560	163,223
	Bundled Self-generation Service				
26	Self-generation GSG-1	-	-	-	-
27	Self-generation GSG-2	23	177,359	14	173,301
28	Total Bundled Self-generation	23	177,359	14	173,301
	Bundled Other Service				
29	Wholesale	1	260,664	-	-
30	Grand Rapids	1	14,220	-	-
31	Total Bundled Other	2	274,884	-	-
32	Cycle Billed Bundled Service	1,893,532	32,949,131	1,917,136	30,366,110
33	Unbilled		248,222		-
34	Calendar Bundled Service	1,893,532	33,197,353	1,917,136	30,366,110
	ROA Secondary Service				
35	Secondary Energy-only GS	80	18,520	85	18,386
36	Secondary Demand GSD	464	178,044	472	171,253
37	Total ROA Secondary	544	196,564	556	189,639
	ROA Primary Service				
38	Primary Energy-only GP	59	72,767	60	71,144
39	Primary Demand GPD	358	3,328,394	356	3,291,840
40	Total ROA Primary	417	3,401,161	417	3,362,984
41	Cycle Billed ROA Service	961	3,597,725	973	3,552,623
42	Unbilled ROA		(15,136)		-
43	Calendar ROA Service	961	3,582,589	973	3,552,623
44	**Cycle Billed Total Deliveries**	1,894,493	36,546,856	1,918,109	33,918,733
45	**Unbilled**	-	233,086		-
46	**Calendar Total Deliveries**	1,894,493	36,779,942	1,918,109	33,918,733

Schedule E-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Annual System Load Factor
2020 - 2024 Historical / 2025 - 2029 Forecast

Case No.: U-21870
Exhibit No.: A-15 (EMB-5)
Schedule: E-4
Page: 1 of 1
Witness: EMBreuring
Date: June 2025

Line No.	Year		(a) System Output GWh	(b) System Peak Demand MW	(c) Annual Load Factor
1	2020	Hist	38,195	8,215	52.9%
2	2021	Hist	39,021	7,951	56.0%
3	2022	Hist	40,108	8,061	56.8%
4	2023	Hist	39,000	8,067	55.2%
5	2024	Hist	39,731	8,030	56.3%
6	2025	Fcst	39,216	7,651	58.5%
7	2026	Fcst	40,420	7,631	60.5%
8	Test Year	Fcst	40,713	7,631	60.9%
9	2027	Fcst	41,806	7,839	60.9%
10	2028	Fcst	42,413	8,079	59.8%
11	2029	Fcst	44,013	8,226	61.1%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Projected 12-Month Period Ending April 30, 2027
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**	15,367,518	8,976,442	3,896,466	214,108	2,244,459	36,042
2	**Revenue**						
3	Total Rate Revenue	4,434,089	2,321,406	1,105,262	39,312	964,811	3,298
4	Total Revenue Credits	586,534	255,926	134,119	3,082	176,454	16,953
5	Total Revenue	5,020,623	2,577,332	1,239,381	42,393	1,141,265	20,252
6	**Expenses:**						
7	Fuel and P&I Expense	1,681,377	735,673	401,007	8,016	528,177	8,503
8	Transmission Expense	631,863	297,311	151,998	2,017	178,174	2,363
9	Other O & M Expense	804,952	506,369	191,604	6,477	99,096	1,406
10	Depreciation & Amortization Expense	813,088	462,045	200,827	13,734	134,503	1,980
11	Other Taxes	351,612	198,508	92,497	1,921	57,649	1,037
12	Federal Income Taxes	46,009	23,538	12,563	638	8,960	309
13	Total Expenses	4,328,901	2,223,445	1,050,497	32,802	1,006,559	15,599
14	Net Operating Income	691,722	353,887	188,885	9,592	134,706	4,653
15	Other Income Adjustments	16,026	9,174	4,157	74	2,581	40
16	Adjusted Net Operating Income	707,748	363,061	193,042	9,666	137,287	4,693
17	Return on Rate Base @ 6.35%	975,589	569,859	247,363	13,592	142,487	2,288
18	Income Deficiency (Sufficiency)	267,840	206,798	54,320	3,926	5,200	(2,404)
19	Revenue Deficiency (Sufficiency)	358,392	276,712	72,685	5,254	6,958	(3,217)
20	Additional Rev Requirement	77,486	37,910	18,574	219	20,485	298
21	Total Revenue Deficiency (Sufficiency)	435,877	314,623	91,259	5,472	27,443	(2,920)
22	Revenue Requirement/Total Cost of Service	5,456,501	2,891,955	1,330,641	47,865	1,168,708	17,332
23	Less: Revenue Credits	586,534	255,926	134,119	3,082	176,454	16,953
24	**Proposed Rate Design Revenue**	**4,869,967**	**2,636,029**	**1,196,522**	**44,784**	**992,254**	**379**
25	Production: Net Capacity Cost	417,794	212,965	100,403	805	102,257	1,364
26	Production: Capacity Related Cost Offset	800,952	384,727	191,455	2,551	219,553	2,667
27	Production: Non-Capacity Related Cost	1,415,735	628,094	344,633	6,344	443,985	(7,321)
28	Distribution: Demand Related Cost	1,978,181	1,216,144	513,498	33,571	211,414	3,554
29	Distribution: Customer Related Cost	257,305	194,099	46,533	1,513	15,046	114
30	Full Service MWH Sales	30,248,550	12,685,410	7,054,196	163,223	10,172,419	173,301
31	ROA MWH Sales	3,552,623	-	189,639	-	3,362,984	-
32	MWH Sales	33,801,173	12,685,410	7,243,836	163,223	13,535,403	173,301
33	Customers	1,918,106	1,680,798	227,572	5,560	4,163	14

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**	8,976,442	8,976,442	2,441,896	1,454,570	3,896,466	7,949	178,725	27,434	214,108
2	**Revenue**									
3	Total Rate Revenue	2,321,406	2,321,406	684,767	420,495	1,105,262	1,521	28,047	9,744	39,312
4	Total Revenue Credits	255,926	255,926	79,117	55,002	134,119	201	1,166	1,715	3,082
5	Total Revenue	2,577,332	2,577,332	763,884	475,497	1,239,381	1,721	29,213	11,459	42,393
6	**Expenses:**									
7	Fuel and P&I Expense	735,673	735,673	236,726	164,281	401,007	482	2,441	5,093	8,016
8	Transmission Expense	297,311	297,311	91,856	60,142	151,998	111	429	1,476	2,017
9	Other O & M Expense	506,369	506,369	121,248	70,356	191,604	331	4,767	1,378	6,477
10	Depreciation & Amortization Expense	462,045	462,045	126,604	74,223	200,827	396	11,871	1,466	13,734
11	Other Taxes	198,508	198,508	57,114	35,383	92,497	137	1,088	696	1,921
12	Federal Income Taxes	23,538	23,538	8,129	4,435	12,563	16	537	84	638
13	Total Expenses	2,223,445	2,223,445	641,676	408,821	1,050,497	1,474	21,134	10,194	32,802
14	Net Operating Income	353,887	353,887	122,208	66,677	188,885	247	8,079	1,265	9,592
15	Other Income Adjustments	9,174	9,174	2,558	1,599	4,157	6	37	32	74
16	Adjusted Net Operating Income	363,061	363,061	124,766	68,276	193,042	253	8,116	1,297	9,666
17	Return on Rate Base @ 6.35%	569,859	569,859	155,021	92,342	247,363	505	11,346	1,742	13,592
18	Income Deficiency (Sufficiency)	206,798	206,798	30,254	24,066	54,320	252	3,230	444	3,926
19	Revenue Deficiency (Sufficiency)	276,712	276,712	40,483	32,202	72,685	337	4,322	595	5,254
20	Additional Rev Requirement	37,910	37,910	11,235	7,339	18,574	7	36	175	219
21	Total Revenue Deficiency (Sufficiency)	314,623	314,623	51,718	39,541	91,259	344	4,358	770	5,472
22	Revenue Requirement/Total Cost of Service	2,891,955	2,891,955	815,602	515,039	1,330,641	2,065	33,571	12,229	47,865
23	Less: Revenue Credits	255,926	255,926	79,117	55,002	134,119	201	1,166	1,715	3,082
24	**Proposed Rate Design Revenue**	**2,636,029**	**2,636,029**	**736,485**	**460,036**	**1,196,522**	**1,865**	**32,405**	**10,514**	**44,784**
25	Production: Net Capacity Cost	212,965	212,965	61,392	39,011	100,403	3	-	801	805
26	Production: Capacity Related Cost Offset	384,727	384,727	115,438	76,016	191,455	105	494	1,952	2,551
27	Production: Non-Capacity Related Cost	628,094	628,094	204,672	139,961	344,633	380	1,819	4,145	6,344
28	Distribution: Demand Related Cost	1,216,144	1,216,144	317,853	195,645	513,498	1,297	28,743	3,531	33,571
29	Distribution: Customer Related Cost	194,099	194,099	37,130	9,403	46,533	79	1,349	85	1,513
30	Full Service MWH Sales	12,685,410	12,685,410	4,126,393	2,927,804	7,054,196	10,777	54,640	97,806	163,223
31	ROA MWH Sales	-	-	18,386	171,253	189,639	-	-	-	-
32	MWH Sales	12,685,410	12,685,410	4,144,779	3,099,057	7,243,836	10,777	54,640	97,806	163,223
33	Customers	1,680,798	1,680,798	206,948	20,624	227,572	399	4,696	465	5,560

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**	196,802	44,712	80,756	778,198	178,347	281,920	634,382	39,637	8,100	1,604	2,244,459
2	**Revenue**											
3	Total Rate Revenue	73,817	37,422	43,192	336,047	83,685	122,725	241,478	21,284	4,442	718	964,811
4	Total Revenue Credits	11,620	5,812	8,358	57,234	19,680	24,830	42,397	5,515	898	110	176,454
5	Total Revenue	85,437	43,234	51,550	393,282	103,365	147,555	283,875	26,799	5,340	828	1,141,265
6	**Expenses:**											
7	Fuel and P&I Expense	35,814	17,219	25,342	175,655	56,437	72,569	125,642	16,507	2,639	354	528,177
8	Transmission Expense	13,412	5,476	8,439	62,683	17,343	23,281	41,382	5,209	820	128	178,174
9	Other O & M Expense	8,425	1,928	3,442	36,034	6,614	11,430	29,109	1,699	344	73	99,096
10	Depreciation & Amortization Expense	11,830	3,231	5,357	47,577	10,784	16,022	36,212	2,895	507	89	134,503
11	Other Taxes	4,607	1,688	2,150	19,694	4,918	7,445	15,930	956	222	41	57,649
12	Federal Income Taxes	708	854	425	3,220	453	1,048	2,220	(29)	50	9	8,960
13	Total Expenses	74,796	30,395	45,155	344,864	96,549	131,795	250,494	27,237	4,582	693	1,006,559
14	Net Operating Income	10,642	12,839	6,395	48,418	6,816	15,760	33,381	(438)	758	134	134,706
15	Other Income Adjustments	214	55	99	932	179	313	726	50	10	2	2,581
16	Adjusted Net Operating Income	10,856	12,894	6,495	49,350	6,995	16,074	34,107	(388)	768	136	137,287
17	Return on Rate Base @ 6.35%	12,494	2,838	5,127	49,403	11,322	17,897	40,273	2,516	514	102	142,487
18	Income Deficiency (Sufficiency)	1,638	(10,056)	(1,368)	53	4,327	1,824	6,166	2,904	(254)	(34)	5,200
19	Revenue Deficiency (Sufficiency)	2,191	(13,455)	(1,830)	71	5,790	2,440	8,251	3,886	(340)	(46)	6,958
20	Additional Rev Requirement	1,554	628	956	7,251	1,813	2,563	5,051	570	88	12	20,485
21	Total Revenue Deficiency (Sufficiency)	3,746	(12,827)	(874)	7,322	7,603	5,003	13,301	4,456	(252)	(34)	27,443
22	Revenue Requirement/Total Cost of Service	89,183	30,407	50,676	400,603	110,968	152,558	297,176	31,254	5,088	793	1,168,708
23	Less: Revenue Credits	11,620	5,812	8,358	57,234	19,680	24,830	42,397	5,515	898	110	176,454
24	**Proposed Rate Design Revenue**	**77,563**	**24,595**	**42,318**	**343,369**	**91,288**	**127,728**	**254,779**	**25,740**	**4,190**	**683**	**992,254**
25	Production: Net Capacity Cost	8,184	2,990	4,660	37,195	8,363	12,328	25,472	2,621	392	52	102,257
26	Production: Capacity Related Cost Offset	16,505	4,644	10,117	77,849	19,870	27,665	54,829	6,867	1,061	146	219,553
27	Production: Non-Capacity Related Cost	31,046	14,175	21,311	150,289	46,743	60,435	103,713	13,757	2,190	325	443,985
28	Distribution: Demand Related Cost	18,762	2,635	5,751	72,741	15,642	26,281	66,548	2,396	511	147	211,414
29	Distribution: Customer Related Cost	3,066	150	480	5,296	669	1,019	4,217	100	36	14	15,046
30	Full Service MWH Sales	659,010	343,708	493,168	3,289,071	1,158,158	1,441,363	2,395,375	332,592	53,237	6,737	10,172,419
31	ROA MWH Sales	71,144	-	-	-	1,265,948	1,076,272	949,620	-	-	-	3,362,984
32	MWH Sales	730,153	343,708	493,168	3,289,071	2,424,106	2,517,636	3,344,995	332,592	53,237	6,737	13,535,403
33	Customers	1,420	21	80	1,413	36	98	1,077	5	7	5	4,163

Projected 12-Month Period Ending April 30, 2027
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(g) Total Lighting & Unmetered	(f) Total Primary	(h) Rate GSG
1	**Net Plant**						
2	Production	2,260,789	1,106,100	541,939	6,377	597,691	8,682
3	Transmission	-	-	-	-	-	-
4	Distribution	10,295,898	6,195,814	2,686,503	190,920	1,200,971	21,690
5	General/Common/Intangible	751,416	461,000	179,035	5,568	104,331	1,482
6	Plant Purchased/Sold	0	0	0	0	0	0
7	Total Net Plant	13,308,103	7,762,914	3,407,477	202,865	1,902,993	31,855
8	**Working Capital**						
9	Total Current Assets	3,145,271	1,862,960	760,129	28,284	487,452	6,446
10	Total Current Liabilities	1,019,384	608,512	254,150	15,629	138,955	2,137
11	Total Working Capital	2,125,887	1,254,448	505,979	12,654	348,496	4,309
	Adjustments to Rate Base						
13	Additions to Rate Base	0	0	0	0	0	0
14	Deductions from Rate Base	66,473	40,920	16,989	1,411	7,030	122
15	Total Adjustments to Rate Base	(66,473)	(40,920)	(16,989)	(1,411)	(7,030)	(122)
16	**Total Rate Base**	**15,367,518**	**8,976,442**	**3,896,466**	**214,108**	**2,244,459**	**36,042**
17	**Production Expense**						
18	Fuel Expense	548,348	232,032	130,596	2,911	179,851	2,959
19	Purchased & Interchange Power Expense	1,133,028	503,642	270,412	5,104	348,326	5,544
20	Total Fuel and P&I Expense	1,681,377	735,673	401,007	8,016	528,177	8,503
21	Fossil O&M Exp	55,255	26,416	13,227	183	15,200	230
22	Nuclear O&M Exp	0	-	-	-	-	-
23	Hydro O&M Exp	13,209	6,255	3,160	46	3,691	57
23	Other Power Gen O&M Exp	64,631	31,621	15,493	182	17,087	248
24	Other Power Supply O&M Exp	5,268	2,578	1,263	15	1,393	20
25	Total Production O&M Expense	138,363	66,869	33,143	426	37,370	555
26	Total Production (Inc. Fuel and P&I) O&M Expense	1,819,739	802,542	434,150	8,442	565,547	9,058
27	**Transmission & Distribution Expense**						
28	Trans O&M Exp	631,863	297,311	151,998	2,017	178,174	2,363
29	Other O&M Adjustments	0	0	0	0	0	0
30	Distr Oper Exp	129,682	85,509	31,542	3,510	8,994	127
31	Distr Maint Exp	359,273	233,468	90,727	1,464	33,110	504
32	Total Transmission & Distribution O&M Expense	1,120,818	616,289	274,267	6,991	220,278	2,994
33	**Customer Related Expense**						
34	Customer Accounts Exp	59,788	44,699	9,899	266	4,909	15
35	Customer Service Exp	7,158	4,319	1,222	28	1,569	20
36	Other Customer Exp	16,687	13,849	2,665	85	88	1
37	Total Customer O&M Expense	83,634	62,866	13,787	379	6,566	36
38	**Admin & General Expense**	94,000	57,657	22,405	697	13,056	186
39	**Total O&M Expense**	**3,118,192**	**1,539,354**	**744,609**	**16,509**	**805,447**	**12,273**

Line No.	(a) Description	(b)	(c) Rate RS	(d) Total Residential	(e) Rate GS	(f) Rate GSD	(g) Commercial Secondary	(m) Rate GML	(n) - Rate UUL	(o) Rate GU	(p) Total Lighting & Unmetered
1	**Net Plant**										
2	Production		1,106,100	1,106,100	327,807	214,132	541,939	219	1,041	5,116	6,377
3	Transmission		-	-	-	-	-	-	-	-	-
4	Distribution		6,195,814	6,195,814	1,696,573	989,930	2,686,503	6,800	167,074	17,046	190,920
5	General/Common/Intangible		461,000	461,000	112,510	66,525	179,035	281	3,963	1,323	5,568
6	Plant Purchased/Sold		0	0	0	0	0	0	0	0	0
7	Total Net Plant		7,762,914	7,762,914	2,136,890	1,270,587	3,407,477	7,300	172,079	23,486	202,865
8	**Working Capital**										
9	Total Current Assets		1,862,960	1,862,960	475,677	284,452	760,129	1,235	21,222	5,826	28,284
10	Total Current Liabilities		608,512	608,512	159,892	94,258	254,150	540	13,317	1,772	15,629
11	Total Working Capital		1,254,448	1,254,448	315,785	190,194	505,979	695	7,905	4,055	12,654
	Adjustments to Rate Base										
13	Additions to Rate Base		0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base		40,920	40,920	10,779	6,211	16,989	46	1,259	106	1,411
15	Total Adjustments to Rate Base		(40,920)	(40,920)	(10,779)	(6,211)	(16,989)	(46)	(1,259)	(106)	(1,411)
16	**Total Rate Base**		**8,976,442**	**8,976,442**	**2,441,896**	**1,454,570**	**3,896,466**	**7,949**	**178,725**	**27,434**	**214,108**
17	**Production Expense**										
18	Fuel Expense		232,032	232,032	76,562	54,034	130,596	186	948	1,778	2,911
19	Purchased & Interchange Power Expense		503,642	503,642	160,164	110,247	270,412	296	1,494	3,315	5,104
20	Total Fuel and P&I Expense		735,673	735,673	236,726	164,281	401,007	482	2,441	5,093	8,016
21	Fossil O&M Exp		26,416	26,416	7,953	5,274	13,227	8	39	135	183
22	Nuclear O&M Exp		-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp		6,255	6,255	1,896	1,265	3,160	2	11	33	46
23	Other Power Gen O&M Exp		31,621	31,621	9,371	6,122	15,493	6	30	146	182
24	Other Power Supply O&M Exp		2,578	2,578	764	499	1,263	1	2	12	15
25	Total Production O&M Expense		66,869	66,869	19,984	13,159	33,143	17	82	327	426
26	Total Production (Inc. Fuel and P&I) O&M Expense		802,542	802,542	256,710	177,440	434,150	499	2,524	5,420	8,442
27	**Transmission & Distribution Expense**										
28	Trans O&M Exp		297,311	297,311	91,856	60,142	151,998	111	429	1,476	2,017
29	Other O&M Adjustments		0	0	0	0	0	0	0	0	0
30	Distr Oper Exp		85,509	85,509	19,621	11,921	31,542	97	3,196	218	3,510
31	Distr Maint Exp		233,468	233,468	56,948	33,779	90,727	159	712	594	1,464
32	Total Transmission & Distribution O&M Expense		616,289	616,289	168,425	105,842	274,267	367	4,336	2,287	6,991
33	**Customer Related Expense**										
34	Customer Accounts Exp		44,699	44,699	7,439	2,461	9,899	15	195	55	266
35	Customer Service Exp		4,319	4,319	830	393	1,222	2	14	12	28
36	Other Customer Exp		13,849	13,849	2,346	319	2,665	6	71	7	85
37	Total Customer O&M Expense		62,866	62,866	10,615	3,172	13,787	23	281	75	379
38	**Admin & General Expense**		57,657	57,657	14,080	8,325	22,405	35	496	166	697
39	**Total O&M Expense**		**1,539,354**	**1,539,354**	**449,830**	**294,779**	**744,609**	**925**	**7,637**	**7,947**	**16,509**

Line No.	(a) Description	(b)	(c) 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		45,351	18,326	27,900	211,554	52,901	74,769	147,365	16,626	2,563	337	597,691
3	Transmission		-	-	-	-	-	-	-	-	-	-	-
4	Distribution		115,745	15,075	35,128	406,656	91,803	153,471	364,734	13,602	3,794	961	1,200,971
5	General/Common/Intangible		8,694	2,239	3,861	37,710	7,382	12,323	29,701	1,972	377	73	104,331
6	Plant Purchased/Sold		0	0	0	0	0	0	0	0	0	0	0
7	Total Net Plant		169,790	35,641	66,890	655,920	152,086	240,563	541,800	32,200	6,733	1,370	1,902,993
8	**Working Capital**												
9	Total Current Assets		40,022	11,914	18,987	173,415	37,468	59,138	134,356	9,932	1,879	340	487,452
10	Total Current Liabilities		12,315	2,758	4,923	48,721	10,691	16,927	39,611	2,418	491	100	138,955
11	Total Working Capital		27,707	9,156	14,064	124,694	26,777	42,211	94,746	7,514	1,388	240	348,496
	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		695	85	198	2,416	515	854	2,164	76	21	6	7,030
15	Total Adjustments to Rate Base		(695)	(85)	(198)	(2,416)	(515)	(854)	(2,164)	(76)	(21)	(6)	(7,030)
16	**Total Rate Base**		**196,802**	**44,712**	**80,756**	**778,198**	**178,347**	**281,920**	**634,382**	**39,637**	**8,100**	**1,604**	**2,244,459**
17	**Production Expense**												
18	Fuel Expense		11,870	5,941	8,682	58,950	19,958	25,207	42,432	5,760	927	125	179,851
19	Purchased & Interchange Power Expense		23,945	11,277	16,660	116,705	36,479	47,362	83,210	10,748	1,712	229	348,326
20	Total Fuel and P&I Expense		35,814	17,219	25,342	175,655	56,437	72,569	125,642	16,507	2,639	354	528,177
21	Fossil O&M Exp		1,123	477	718	5,308	1,395	1,935	3,729	439	68	9	15,200
22	Nuclear O&M Exp		-	-	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp		270	117	175	1,282	343	473	904	108	17	2	3,691
23	Other Power Gen O&M Exp		1,296	524	798	6,048	1,512	2,137	4,213	475	73	10	17,087
24	Other Power Supply O&M Exp		106	43	65	493	123	174	343	39	6	1	1,393
25	Total Production O&M Expense		2,794	1,160	1,755	13,131	3,374	4,720	9,189	1,061	165	22	37,370
26	Total Production (Inc. Fuel and P&I) O&M Expense		38,609	18,378	27,097	188,786	59,811	77,289	134,831	17,568	2,803	375	565,547
27	**Transmission & Distribution Expense**												
28	Trans O&M Exp		13,412	5,476	8,439	62,683	17,343	23,281	41,382	5,209	820	128	178,174
29	Other O&M Adjustments		0	0	0	0	0	0	0	0	0	0	0
30	Distr Oper Exp		776	52	155	3,545	339	795	3,255	50	18	8	8,994
31	Distr Maint Exp		3,271	209	769	12,529	1,263	3,453	11,314	190	84	29	33,110
32	Total Transmission & Distribution O&M Expense		17,459	5,737	9,363	78,757	18,945	27,529	55,951	5,450	923	165	220,278
33	**Customer Related Expense**												
34	Customer Accounts Exp		386	186	220	1,698	433	625	1,223	112	23	4	4,909
35	Customer Service Exp		87	40	57	382	280	291	388	38	6	1	1,569
36	Other Customer Exp		23	1	2	30	2	5	23	1	0	0	88
37	Total Customer O&M Expense		496	227	279	2,111	715	920	1,634	151	29	5	6,566
38	**Admin & General Expense**		1,088	280	483	4,719	924	1,542	3,717	247	47	9	13,056
39	**Total O&M Expense**		**57,651**	**24,623**	**37,222**	**274,372**	**80,395**	**107,280**	**196,132**	**23,415**	**3,803**	**554**	**805,447**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Case No.: U-21870
Exhibit No.:A-16 (EAD-1)
Schedule F-1
Page: 7 of 28
Witness: EADavis
Date: June 2025

Projected 12-Month Period Ending April 30, 2027
Version 1
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(g) Total Lighting & Unmetered	(f) Total Primary	(h) Rate GSG
	Input Allocation Schedules						
1	Energy @ Generation	100.000	42.781	23.790	0.550	32.323	0.557
2	Energy On-Peak @ Generation	100.000	40.400	25.227	0.415	33.526	0.432
3	Energy Off-Peak @ Generation	100.000	44.804	21.917	0.691	31.904	0.684
4	Energy On-Peak @ Generation Summer	100.000	41.357	25.482	0.340	32.381	0.440
5	Energy Off-Peak @ Generation Summer	100.000	45.009	22.115	0.614	31.526	0.736
6	Energy On-Peak @ Generation Non-Summer	100.000	39.837	25.077	0.459	34.199	0.428
7	Energy Off-Peak @ Generation Non-Summer	100.000	44.690	21.807	0.733	32.114	0.655
8	Energy Critical On-Peak @ Gen	100.000	43.786	25.634	0.257	30.012	0.310
9	Energy Summer Mid-Peak @ Gen	100.000	40.455	25.426	0.370	33.261	0.488
10	12CP Dmd @ Generation	100.000	47.053	24.056	0.319	28.198	0.374
11	4CP Dmd @ Generation	100.000	50.974	24.032	0.193	24.476	0.327
12	Class Peak @ Voltage 1	100.000	47.646	22.193	0.352	29.172	0.637
13	Production Revenue	100.000	45.243	24.069	0.404	30.272	0.012
14	Distribution Revenue	100.000	61.945	26.046	1.591	10.257	0.160
15	Total Rate Revenue	100.000	51.741	24.838	0.866	22.485	0.070
16	Billed Sales	100.000	37.529	21.431	0.483	40.044	0.513
17	Number Of Customers	100.000	87.628	11.864	0.290	0.217	0.001
18	Weighted Customer	100.000	60.171	28.622	0.054	11.116	0.038
	*Calculated Allocation Schedules						
19	4CP 75/0/25	100.000	48.925	23.971	0.282	26.437	0.384
20	4CP 75/0/25 Including ROA	100.000	47.609	23.179	0.404	28.402	0.406
21	4CP 75/0/25 Including ROA	100.000	47.609	23.179	0.404	28.402	0.406
22	4CP 75/0/25 Including ROA	100.000	47.609	23.179	0.404	28.402	0.406
23	Class Peak @ Voltage 2	100.000	50.507	23.525	0.373	24.919	0.676
24	Class Peak Voltage 1 Only	100.000	-	-	-	95.217	4.783
25	Class Peak Voltage 2 Only	100.000	-	-	-	95.360	4.640
26	Class Peak @ Voltage 1 excluding Voltage 2	100.000	50.758	23.642	0.375	24.849	0.376
27	Class Peak @ Voltage 3	100.000	54.198	25.244	0.400	20.079	0.078
28	Class Peak @ Voltage 4	100.000	67.881	31.618	0.501	-	-
29	Class Peak for Streetlighting	100.000	-	-	100.000	-	-
30	Class Peak @ Single Phase	100.000	67.881	31.618	0.501	-	-
31	Billed Sales - Primary	100.000	46.220	26.393	0.595	26.725	0.068
32	Customers - Residential	100.000	100.000	-	-	-	-
33	Customers - Drops	100.000	-	100.000	-	-	-
34	Customers - Non-Primary	100.000	88.057	11.922	0.021	-	-
35	Customers - NonMunicipal	100.000	87.883	11.899	-	0.218	0.001
36	Customers - Commercial & Primary	100.000	-	98.198	-	1.796	0.006
37	Customer Count (CCC)	100.000	93.559	6.441	-	-	-
38	Customer Count (BCC)	100.000	-	91.992	4.573	3.424	0.012
39	PIS - HVD (Voltage 1)	100.000	50.752	23.639	0.374	24.620	0.614
40	PIS - HVD (Voltage 2)	100.000	50.414	23.482	0.372	25.192	0.540
41	PIS - HVD (Voltage 1) Substations	100.000	50.507	23.525	0.373	24.919	0.676
42	PIS - HVD (Voltage 2) Substations	100.000	41.775	19.458	0.308	37.335	1.124
43	PIS - OH LVD System	100.000	64.018	29.818	0.472	5.669	0.022
44	PIS - LVD Distribution	100.000	63.318	25.881	2.402	8.278	0.122
45	PIS- OH (LVD & HVD) Lines & Services	100.000	66.522	25.401	0.389	7.595	0.093
46	PIS- UG LVD Distribution	100.000	63.659	29.651	0.470	6.132	0.088
47	PIS- Total Distribution	100.000	61.559	25.558	2.123	10.576	0.183

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

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Line No.	(a) Description	(b)	(c) Rate RS	(d) Total Residential	(e) Rate GS	(f) Rate GSD	(g) Commercial Secondary	(m) Rate GML	(n) Rate UUL	(o) Rate GU	(p) Lighting & Unmetered
	Input Allocation Schedules										
1	Energy @ Generation	100	42.781	42.781	13.916	9.874	23.790	0.036	0.184	0.330	0.550
2	Energy On-Peak @ Generation	101	40.400	40.400	15.034	10.193	25.227	0.018	0.096	0.300	0.415
3	Energy Off-Peak @ Generation	102	44.804	44.804	12.520	9.398	21.917	0.056	0.277	0.357	0.691
4	Energy On-Peak @ Generation Summer	103	41.357	41.357	15.224	10.258	25.482	0.009	0.058	0.273	0.340
5	Energy Off-Peak @ Generation Summer	104	45.009	45.009	12.643	9.472	22.115	0.046	0.237	0.331	0.614
6	Energy On-Peak @ Generation Non-Summer	105	39.837	39.837	14.922	10.155	25.077	0.023	0.119	0.317	0.459
7	Energy Off-Peak @ Generation Non-Summer	106	44.690	44.690	12.451	9.356	21.807	0.061	0.300	0.372	0.733
8	Energy Critical On-Peak @ Gen	107	43.786	43.786	15.378	10.256	25.634	0.001	0.004	0.252	0.257
9	Energy Summer Mid-Peak @ Gen	108	40.455	40.455	15.167	10.258	25.426	0.011	0.079	0.280	0.370
10	12CP Dmd @ Generation	120	47.053	47.053	14.537	9.518	24.056	0.018	0.068	0.234	0.319
11	4CP Dmd @ Generation	121	50.974	50.974	14.694	9.337	24.032	0.001	-	0.192	0.193
12	Class Peak @ Voltage 1	127	47.646	47.646	13.667	8.525	22.193	0.040	0.160	0.152	0.352
13	Production Revenue	141	45.243	45.243	14.305	9.764	24.069	0.022	0.108	0.273	0.404
14	Distribution Revenue	142	61.945	61.945	16.964	9.082	26.046	0.054	1.386	0.152	1.591
15	Total Rate Revenue	143	51.741	51.741	15.339	9.498	24.838	0.034	0.605	0.226	0.866
16	Billed Sales	150	37.529	37.529	12.262	9.168	21.431	0.032	0.162	0.289	0.483
17	Number Of Customers	160	87.628	87.628	10.789	1.075	11.864	0.021	0.245	0.024	0.290
18	Weighted Customer	170	60.171	60.171	23.312	5.310	28.622	0.054	-	-	0.054
	*Calculated Allocation Schedules										
19	4CP 75/0/25	220	48.925	48.925	14.500	9.472	23.971	0.010	0.046	0.226	0.282
20	4CP 75/0/25 Including ROA	222	47.609	47.609	14.037	9.142	23.179	0.040	0.169	0.195	0.404
21	4CP 75/0/25 Including ROA	224	47.609	47.609	14.037	9.142	23.179	0.040	0.169	0.195	0.404
22	4CP 75/0/25 Including ROA	226	47.609	47.609	14.037	9.142	23.179	0.040	0.169	0.195	0.404
23	Class Peak @ Voltage 2	122	50.507	50.507	14.488	9.037	23.525	0.042	0.169	0.161	0.373
24	Class Peak Voltage 1 Only	123	-	-	-	-	-	-	-	-	-
25	Class Peak Voltage 2 Only	124	-	-	-	-	-	-	-	-	-
26	Class Peak @ Voltage 1 excluding Voltage 2	125	50.758	50.758	14.560	9.082	23.642	0.042	0.170	0.162	0.375
27	Class Peak @ Voltage 3	230	54.198	54.198	15.547	9.697	25.244	0.045	0.182	0.173	0.400
28	Class Peak @ Voltage 4	231	67.881	67.881	19.472	12.146	31.618	0.057	0.228	0.216	0.501
29	Class Peak for Streetlighting	233	-	-	-	-	-	19.935	80.065	-	100.000
30	Class Peak @ Single Phase	235	67.881	67.881	19.472	12.146	31.618	0.057	0.228	0.216	0.501
31	Billed Sales - Primary	253	46.220	46.220	15.102	11.291	26.393	0.039	0.199	0.356	0.595
32	Customers - Residential	260	100.000	100.000	-	-	-	-	-	-	-
33	Customers - Drops	261	-	-	90.937	9.063	100.000	-	-	-	-
34	Customers - Non-Primary	263	88.057	88.057	10.842	1.080	11.922	0.021	-	-	0.021
35	Customers - NonMunicipal	264	87.883	87.883	10.821	1.078	11.899	-	-	-	-
36	Customers - Commercial & Primary	267	-	-	89.298	8.899	98.198	-	-	-	-
37	Customer Count (CCC)	161	93.559	93.559	6.388	0.054	6.441	-	-	-	-
38	Customer Count (BCC)	162	-	-	75.822	16.170	91.992	0.328	3.862	0.382	4.573
39	PIS - HVD (Voltage 1)	301	50.752	50.752	14.558	9.081	23.639	0.042	0.170	0.162	0.374
40	PIS - HVD (Voltage 2)	302	50.414	50.414	14.461	9.020	23.482	0.042	0.169	0.161	0.372
41	PIS - HVD (Voltage 1) Substations	303	50.507	50.507	14.488	9.037	23.525	0.042	0.169	0.161	0.373
42	PIS - HVD (Voltage 2) Substations	304	41.775	41.775	11.983	7.475	19.458	0.035	0.140	0.133	0.308
43	PIS - OH LVD System	305	64.018	64.018	18.364	11.455	29.818	0.053	0.215	0.204	0.472
44	PIS - LVD Distribution	306	63.318	63.318	16.490	9.391	25.881	0.073	2.169	0.160	2.402
45	PIS- OH (LVD & HVD) Lines & Services	307	66.522	66.522	15.897	9.504	25.401	0.044	0.177	0.168	0.389
46	PIS- UG LVD Distribution	308	63.659	63.659	18.261	11.390	29.651	0.053	0.214	0.203	0.470
47	PIS- Total Distribution	309	61.559	61.559	16.215	9.343	25.558	0.069	1.894	0.160	2.123

*Calculated allocation schedules may vary between productio

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Line No.	(a) Description	(b)	(c) 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	100	2.147	1.095	1.591	10.722	3.354	4.377	7.783	1.060	0.172	0.022	32.323
2	Energy On-Peak @ Generation	101	2.436	1.059	1.628	11.632	3.469	4.473	7.587	1.050	0.161	0.031	33.526
3	Energy Off-Peak @ Generation	102	1.805	1.120	1.529	9.594	3.882	4.778	7.947	1.056	0.181	0.011	31.904
4	Energy On-Peak @ Generation Summer	103	2.405	1.002	1.538	11.336	3.246	4.202	7.537	0.945	0.143	0.028	32.381
5	Energy Off-Peak @ Generation Summer	104	1.804	1.078	1.496	9.598	3.745	4.570	8.063	0.993	0.168	0.011	31.526
6	Energy On-Peak @ Generation Non-Summer	105	2.455	1.092	1.681	11.805	3.600	4.633	7.617	1.112	0.171	0.033	34.199
7	Energy Off-Peak @ Generation Non-Summer	106	1.805	1.144	1.548	9.592	3.958	4.894	7.882	1.092	0.189	0.012	32.114
8	Energy Critical On-Peak @ Gen	107	2.231	0.902	1.399	10.608	2.865	3.867	7.132	0.877	0.117	0.016	30.012
9	Energy Summer Mid-Peak @ Gen	108	2.470	1.039	1.590	11.606	3.387	4.326	7.687	0.970	0.152	0.033	33.261
10	12CP Dmd @ Generation	120	2.123	0.867	1.336	9.920	2.745	3.685	6.549	0.824	0.130	0.020	28.198
11	4CP Dmd @ Generation	121	1.959	0.716	1.115	8.903	2.002	2.951	6.097	0.627	0.094	0.013	24.476
12	Class Peak @ Voltage 1	127	2.145	0.697	1.008	8.183	4.318	4.630	7.420	0.640	0.112	0.019	29.172
13	Production Revenue	141	2.104	1.363	1.488	10.127	3.112	4.084	7.026	0.820	0.131	0.017	30.272
14	Distribution Revenue	142	1.056	0.075	0.270	4.096	0.268	1.014	3.354	0.043	0.064	0.016	10.257
15	Total Rate Revenue	143	1.696	0.862	1.014	7.781	2.006	2.890	5.598	0.518	0.105	0.017	22.485
16	Billed Sales	150	2.160	1.017	1.459	9.731	7.172	7.448	9.896	0.984	0.157	0.020	40.044
17	Number Of Customers	160	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	170	3.005	0.065	0.361	4.140	0.125	0.303	3.065	0.019	0.021	0.011	11.116
	*Calculated Allocation Schedules												
19	4CP 75/0/25	220	2.006	0.811	1.234	9.358	2.340	3.307	6.518	0.735	0.113	0.015	26.437
20	4CP 75/0/25 Including ROA	222	2.168	0.801	0.355	8.930	5.172	1.811	8.360	0.747	0.038	0.020	28.402
21	4CP 75/0/25 Including ROA	224	2.168	0.801	0.355	8.930	5.172	1.811	8.360	0.747	0.038	0.020	28.402
22	4CP 75/0/25 Including ROA	226	2.168	0.801	0.355	8.930	5.172	1.811	8.360	0.747	0.038	0.020	28.402
23	Class Peak @ Voltage 2	122	2.263	-	1.069	8.675	-	4.908	7.865	-	0.119	0.020	24.919
24	Class Peak Voltage 1 Only	123	0.169	11.714	-	-	72.583	-	-	10.752	-	-	95.217
25	Class Peak Voltage 2 Only	124	1.565	-	16.447	-	-	75.520	-	-	1.828	-	95.360
26	Class Peak @ Voltage 1 excluding Voltage 2	125	2.183	0.742	-	8.718	4.600	-	7.905	0.681	-	0.020	24.849
27	Class Peak @ Voltage 3	230	2.309	-	-	9.309	-	-	8.440	-	-	0.022	20.079
28	Class Peak @ Voltage 4	231	-	-	-	-	-	-	-	-	-	-	-
29	Class Peak for Streetlighting	233	-	-	-	-	-	-	-	-	-	-	-
30	Class Peak @ Single Phase	235	-	-	-	-	-	-	-	-	-	-	-
31	Billed Sales - Primary	253	2.529	-	-	11.984	-	-	12.188	-	-	0.025	26.725
32	Customers - Residential	260	-	-	-	-	-	-	-	-	-	-	-
33	Customers - Drops	261	-	-	-	-	-	-	-	-	-	-	-
34	Customers - Non-Primary	263	-	-	-	-	-	-	-	-	-	-	-
35	Customers - NonMunicipal	264	0.074	0.001	0.004	0.074	0.002	0.005	0.056	0.000	0.000	0.000	0.218
36	Customers - Commercial & Primary	267	0.613	0.009	0.035	0.610	0.016	0.042	0.465	0.002	0.003	0.002	1.796
37	Customer Count (CCC)	161	-	-	-	-	-	-	-	-	-	-	-
38	Customer Count (BCC)	162	1.168	0.018	0.066	1.162	0.030	0.080	0.886	0.004	0.006	0.004	3.424
39	PIS - HVD (Voltage 1)	301	2.262	0.036	0.952	8.717	0.221	4.371	7.904	0.033	0.106	0.020	24.620
40	PIS - HVD (Voltage 2)	302	1.934	-	1.685	7.149	-	7.738	6.482	-	0.187	0.017	25.192
41	PIS - HVD (Voltage 1) Substations	303	2.263	-	1.069	8.675	-	4.908	7.865	-	0.119	0.020	24.919
42	PIS - HVD (Voltage 2) Substations	304	2.138	-	3.770	7.175	-	17.311	6.506	-	0.419	0.017	37.335
43	PIS - OH LVD System	305	0.652	-	-	2.628	-	-	2.383	-	-	0.006	5.669
44	PIS - LVD Distribution	306	0.886	0.146	0.116	2.988	0.886	0.442	2.663	0.131	0.012	0.007	8.278
45	PIS- OH (LVD & HVD) Lines & Services	307	0.770	0.033	0.129	3.052	0.202	0.592	2.767	0.030	0.014	0.007	7.595
46	PIS- UG LVD Distribution	308	0.554	0.159	0.008	2.221	0.987	0.037	2.014	0.146	0.001	0.005	6.132
47	PIS- Total Distribution	309	1.046	0.128	0.297	3.635	0.775	1.285	3.255	0.115	0.032	0.009	10.576

*Calculated allocation schedules may vary between productic

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Projected 12-Month Period Ending April 30, 2027
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(thousands of dollars)

Line No.	(a) Description	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(g) Total Lighting & Unmetered	(f) Total Primary	(h) 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	66.558	31.001	0.491	1.942	0.008
5	PIS- Meters	100.000	60.171	28.622	0.054	11.116	0.038
6	PIS - General	100.000	81.876	11.173	0.347	6.511	0.093
7	Total PIS	100.000	58.992	25.109	1.648	14.025	0.225
8	Distribution Depreciation	100.000	65.069	24.363	2.703	7.753	0.113
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	100.000	36.016	16.775	0.266	45.287	1.656
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	100.000	50.804	23.663	0.375	24.664	0.494
11	PIS- LVD OH Lines & Services	100.000	69.145	25.742	0.392	4.704	0.018
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	100.000	-	-	-	95.217	4.783
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	100.000	52.478	24.443	0.387	22.364	0.329
14	CWIP	100.000	57.242	25.941	0.464	16.106	0.247
15	Rate Base- Total	100.000	58.412	25.355	1.393	14.605	0.235
16	Dist Op Expense (LVD) excl Sup & Eng	100.000	66.320	24.356	2.760	6.479	0.084
17	Dist Maint Expense (LVD) excl Sup & Eng	100.000	66.409	25.475	0.412	7.613	0.091
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	100.000	47.369	22.101	0.326	29.417	0.787
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	100.000	47.200	22.010	0.332	29.650	0.808
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.720	23.159	0.367	26.100	0.654
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.476	23.045	0.365	26.467	0.647
22	Total HVD Distribution O&M Expense	100.000	48.815	22.745	0.355	27.390	0.695
23	Total Distribution O&M Expense (excl. HVD)	100.000	66.418	25.162	1.056	7.276	0.089
24	Total Customer Accounts Expense (excl. Supv)	100.000	74.762	16.557	0.445	8.210	0.026
25	Total Customer Accounts & Service Expense	100.000	73.219	16.613	0.440	9.676	0.053
26	Jurisdictional Distribution O&M	100.000	65.236	25.006	1.017	8.611	0.129
27	Pre Tax NOI	100.000	51.160	27.306	1.387	19.474	0.673
28	Depreciation & Amortization Expense	100.000	56.826	24.699	1.689	16.542	0.243
29	Non PSCR O&M Expense	100.000	62.907	23.803	0.805	12.311	0.175
30	Distribution Depreciation Expense	100.000	61.756	25.401	2.916	9.775	0.152
31	Gen/Comm/Int Depreciation Expense	100.000	61.337	23.835	0.741	13.890	0.197
32	Production Labor	100.000	48.925	23.971	0.282	26.437	0.384
33	Total Labor	100.000	61.337	23.835	0.741	13.890	0.197
34	50% O&M, 50% Net Plant	100.000	56.630	25.277	1.336	16.488	0.269
35	50/50 PIS & Labor	100.000	60.165	24.472	1.195	13.957	0.211

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Line No.	(a) Description	(b)	(c) Rate RS	(d) Total Residential	(e) Rate GS	(f) Rate GSD	(g) Commercial Secondary	(m) Rate GML	(n) Rate UUL	(o) Rate GU	(p) Lighting & Unmetered
1	*Calculated Allocation Schedules										
2	PIS- Distribution Services	310	94.121	94.121	5.347	0.533	5.879	-	-	-	-
3	PIS- Streetlighting Equipment	311	-	-	-	-	-	1.423	98.577	-	100.000
4	PIS- Line Equipment	312	66.558	66.558	19.092	11.909	31.001	0.056	0.223	0.212	0.491
5	PIS- Meters	313	60.171	60.171	23.312	5.310	28.622	0.054	-	-	0.054
6	PIS - General	315	81.876	81.876	7.022	4.152	11.173	0.018	0.247	0.083	0.347
7	Total PIS	316	58.992	58.992	15.776	9.333	25.109	0.054	1.419	0.175	1.648
8	Distribution Depreciation	317	65.069	65.069	15.618	8.744	24.363	0.074	2.480	0.149	2.703
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	318	36.016	36.016	10.331	6.444	16.775	0.030	0.121	0.115	0.266
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	319	50.804	50.804	14.573	9.090	23.663	0.042	0.170	0.162	0.375
11	PIS- LVD OH Lines & Services	320	69.145	69.145	16.147	9.595	25.742	0.044	0.178	0.169	0.392
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	321	-	-	-	-	-	-	-	-	-
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	322	52.478	52.478	15.053	9.390	24.443	0.044	0.176	0.167	0.387
14	CWIP	330	57.242	57.242	15.963	9.977	25.941	0.035	0.229	0.200	0.464
15	Rate Base- Total	390	58.412	58.412	15.890	9.465	25.355	0.052	1.163	0.179	1.393
16	Dist Op Expense (LVD) excl Sup & Eng	400	66.320	66.320	15.154	9.202	24.356	0.076	2.517	0.168	2.760
17	Dist Maint Expense (LVD) excl Sup & Eng	401	66.409	66.409	16.014	9.461	25.475	0.045	0.202	0.166	0.412
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	402	47.369	47.369	13.597	8.504	22.101	0.034	0.137	0.155	0.326
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	403	47.200	47.200	13.546	8.465	22.010	0.036	0.143	0.153	0.332
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	404	49.720	49.720	14.262	8.896	23.159	0.042	0.167	0.159	0.367
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	405	49.476	49.476	14.192	8.853	23.045	0.041	0.166	0.158	0.365
22	Total HVD Distribution O&M Expense	406	48.815	48.815	14.005	8.740	22.745	0.040	0.159	0.156	0.355
23	Total Distribution O&M Expense (excl. HVD)	407	66.418	66.418	15.772	9.389	25.162	0.053	0.837	0.167	1.056
24	Total Customer Accounts Expense (excl. Supv)	408	74.762	74.762	12.442	4.116	16.557	0.026	0.327	0.092	0.445
25	Total Customer Accounts & Service Expense	409	73.219	73.219	12.351	4.262	16.613	0.026	0.313	0.100	0.440
26	Jurisdictional Distribution O&M	414	65.236	65.236	15.660	9.346	25.006	0.052	0.799	0.166	1.017
27	Pre Tax NOI	439	51.160	51.160	17.667	9.639	27.306	0.036	1.168	0.183	1.387
28	Depreciation & Amortization Expense	442	56.826	56.826	15.571	9.129	24.699	0.049	1.460	0.180	1.689
29	Non PSCR O&M Expense	443	62.907	62.907	15.063	8.740	23.803	0.041	0.592	0.171	0.805
30	Distribution Depreciation Expense	444	61.756	61.756	16.473	8.928	25.401	0.080	2.689	0.147	2.916
31	Gen/Comm/Int Depreciation Expense	445	61.337	61.337	14.978	8.856	23.835	0.037	0.528	0.176	0.741
32	Production Labor	500	48.925	48.925	14.500	9.472	23.971	0.010	0.046	0.226	0.282
33	Total Labor	502	61.337	61.337	14.978	8.856	23.835	0.037	0.528	0.176	0.741
34	50% O&M, 50% Net Plant	600	56.630	56.630	15.747	9.530	25.277	0.050	1.094	0.191	1.336
35	50/50 PIS & Labor	601	60.165	60.165	15.377	9.095	24.472	0.046	0.973	0.175	1.195

*Calculated allocation schedules may vary between productic

Line No.	(a) Description	(b)	(c) 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	310	-	-	-	-	-	-	-	-	-	-	-
3	PIS- Streetlighting Equipment	311	-	-	-	-	-	-	-	-	-	-	-
4	PIS- Line Equipment	312	0.223	-	-	0.900	-	-	0.816	-	-	0.002	1.942
5	PIS- Meters	313	3.005	0.065	0.361	4.140	0.125	0.303	3.065	0.019	0.021	0.011	11.116
6	PIS - General	315	0.543	0.140	0.241	2.353	0.461	0.769	1.854	0.123	0.023	0.005	6.511
7	Total PIS	316	1.248	0.278	0.502	4.893	1.106	1.720	3.966	0.251	0.050	0.010	14.025
8	Distribution Depreciation	317	0.839	0.075	0.181	2.837	0.447	0.751	2.531	0.066	0.019	0.007	7.753
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	318	1.592	3.930	-	6.186	24.349	-	5.609	3.607	-	0.014	45.287
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	319	2.264	-	1.007	8.726	-	4.623	7.912	-	0.112	0.020	24.664
11	PIS- LVD OH Lines & Services	320	0.541	-	-	2.181	-	-	1.977	-	-	0.005	4.704
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	321	0.169	11.714	-	-	72.583	-	-	10.752	-	-	95.217
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	322	2.287	-	0.503	9.013	-	2.311	8.172	-	0.056	0.021	22.364
14	CWIP	330	1.338	0.346	0.620	5.816	1.119	1.954	4.529	0.313	0.060	0.011	16.106
15	Rate Base- Total	390	1.281	0.291	0.525	5.064	1.161	1.835	4.128	0.258	0.053	0.010	14.605
16	Dist Op Expense (LVD) excl Sup & Eng	400	0.562	0.034	0.097	2.604	0.223	0.512	2.395	0.033	0.012	0.006	6.479
17	Dist Maint Expense (LVD) excl Sup & Eng	401	0.798	0.033	0.131	3.056	0.199	0.583	2.762	0.029	0.014	0.007	7.613
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	402	2.054	1.133	0.607	8.155	6.706	2.506	7.138	1.036	0.064	0.018	29.417
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	403	2.058	1.153	0.583	8.120	6.927	2.485	7.187	1.056	0.062	0.018	29.650
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	404	2.251	-	1.323	8.540	-	6.076	7.743	-	0.147	0.020	26.100
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	405	2.247	-	1.402	8.498	-	6.439	7.705	-	0.156	0.020	26.467
22	Total HVD Distribution O&M Expense	406	2.191	0.345	1.153	8.388	2.068	5.233	7.551	0.316	0.127	0.019	27.390
23	Total Distribution O&M Expense (excl. HVD)	407	0.730	0.032	0.120	2.926	0.202	0.559	2.656	0.030	0.013	0.007	7.276
24	Total Customer Accounts Expense (excl. Supv)	408	0.645	0.312	0.368	2.840	0.725	1.045	2.045	0.187	0.038	0.006	8.210
25	Total Customer Accounts & Service Expense	409	0.705	0.338	0.414	3.107	1.065	1.367	2.405	0.224	0.043	0.007	9.676
26	Jurisdictional Distribution O&M	414	0.828	0.053	0.189	3.287	0.327	0.869	2.980	0.049	0.021	0.008	8.611
27	Pre Tax NOI	439	1.538	1.856	0.925	7.000	0.985	2.278	4.826	(0.063)	0.110	0.019	19.474
28	Depreciation & Amortization Expense	442	1.455	0.397	0.659	5.851	1.326	1.970	4.454	0.356	0.062	0.011	16.542
29	Non PSCR O&M Expense	443	1.047	0.240	0.428	4.477	0.822	1.420	3.616	0.211	0.043	0.009	12.311
30	Distribution Depreciation Expense	444	1.109	0.110	0.263	3.434	0.647	1.049	3.032	0.096	0.027	0.008	9.775
31	Gen/Comm/Int Depreciation Expense	445	1.157	0.298	0.514	5.020	0.983	1.641	3.954	0.262	0.050	0.010	13.890
32	Production Labor	500	2.006	0.811	1.234	9.358	2.340	3.307	6.518	0.735	0.113	0.015	26.437
33	Total Labor	502	1.157	0.298	0.514	5.020	0.983	1.641	3.954	0.262	0.050	0.010	13.890
34	50% O&M, 50% Net Plant	600	1.385	0.367	0.634	5.663	1.415	2.118	4.492	0.339	0.064	0.012	16.488
35	50/50 PIS & Labor	601	1.203	0.288	0.508	4.957	1.045	1.680	3.960	0.257	0.050	0.010	13.957

*Calculated allocation schedules may vary between productic

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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		3,911,520	1,913,727	937,639	11,033	1,034,100	15,022
3	Transmission		0	-	-	-	-	-
4	Distribution		14,018,474	8,629,653	3,582,892	297,567	1,482,660	25,702
5	General/Common/Intangible		1,440,504	883,756	343,223	10,674	200,009	2,842
6	Plant Purchased/Sold		0	0	0	0	0	0
7	Total Plant in Service		19,370,498	11,427,136	4,863,754	319,274	2,716,769	43,565
8	**Depreciation Reserve**							
9	Production		1,829,448	895,065	438,541	5,160	483,656	7,026
10	Transmission		0	-	-	-	-	-
11	Distribution		3,990,342	2,596,488	972,147	107,847	309,363	4,496
12	General/Common/Intangible		830,853	509,710	197,978	6,157	115,369	1,639
13	Total Depreciation Reserve		6,650,643	4,001,263	1,608,666	119,164	908,389	13,162
14	**Construction Work In Progress (CWIP)**							
15	Production		178,717	87,438	42,841	504	47,248	686
16	Transmission		-	-	-	-	-	-
17	Distribution		267,258	162,407	75,646	1,198	27,525	482
18	General/Common/Intangible		132,835	81,477	31,661	985	18,450	262
19	Total CWIP		578,809	331,321	150,147	2,687	93,223	1,430
20	**Future Use**							
21	Production	220	0	0	0	0	0	0
22	Distribution	127	509	242	113	2	148	3
23	Common/General	502	8,930	5,478	2,129	66	1,240	18
24	PHFFU Depreciation Reserve	127	0	0	0	0	0	0
25	Total Future Use		9,439	5,720	2,241	68	1,389	21
26	Total Net Plant		13,308,103	7,762,914	3,407,477	202,865	1,902,993	31,855

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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		3,911,520	1,913,727	937,639	11,033	1,034,100	15,022
3	Generation Step Ups		0	0	0	0	0	0
4	Total Production		3,911,520	1,913,727	937,639	11,033	1,034,100	15,022
5	**Distribution Plant in Service**							
6	Stations and Equipment		3,779,644	2,063,005	960,902	15,223	723,416	17,098
7	Overhead System		6,743,986	4,165,284	1,940,097	30,735	600,541	7,328
8	Underground System		1,268,339	814,325	379,295	6,009	67,742	968
9	Meters and Svc Drops		1,994,151	1,587,038	302,598	13,247	90,961	307
10	St Lgts and OPL		232,354	-	-	232,354	-	-
11	Total Distribution		14,018,474	8,629,653	3,582,892	297,567	1,482,660	25,702
12	**General/Common/Intangible Plant in Service**							
13	Total Gen/Comm/Int Plant		1,440,504	883,756	343,223	10,674	200,009	2,842
14	**Plant Purchased/Sold**		0	0	0	0	0	0
15	**Total Plant in Service**		19,370,498	11,427,136	4,863,754	319,274	2,716,769	43,565

PLANT IN SERVICE (PRODUCTION & TRANSMISSION)

1	**Production Plant in Service**							
2	Fossil (Production-Steam)	220	1,024,947	501,460	245,692	2,891	270,968	3,936
3	Demand Response	220	52,343	25,609	12,547	148	13,838	201
4	Total Hydro	220	888,336	434,622	212,945	2,506	234,852	3,412
5	Other Production	220	1,945,894	952,036	466,455	5,489	514,442	7,473
6	Solar	220	0	0	0	0	0	0
7	Total Production Plant in Service		3,911,520	1,913,727	937,639	11,033	1,034,100	15,022

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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	18,243	8,692	4,049	64	5,322	116
4	HVD (Voltage 1) Other Land & ROW	127	5,915	2,818	1,313	21	1,726	38
5	HVD (Voltage 2) Substation Land & ROW	122	19,395	9,796	4,563	72	4,833	131
6	HVD (Voltage 2) Other Land & ROW	122	75,653	38,210	17,797	282	18,852	511
7	LVD Land & ROW	230	62,103	33,659	15,678	248	12,470	48
8	Total Distribution Land & ROW		181,309	93,176	43,399	688	43,202	845
9	Distribution Substations & Equipment (361/362)							-
10	HVD (Voltage 1) Bulk Power Substations (Shared V2,3,4)	122	535,042	270,236	125,870	1,994	133,327	3,615
11	HVD (Voltage 1) Distribution Substations (Shared V3,4)	230	431,195	233,700	108,852	1,724	86,582	336
13	HVD (Voltage 2) Bulk Power Substations (Shared V2,3,4)	122	33,446	16,892	7,868	125	8,334	226
14	HVD (Voltage 2) Distribution Substations (Shared V3,4)	230	982,300	532,390	247,976	3,928	197,241	765
15	HVD (Voltage 2) Substations (V2 Only)	124	128,234	-	-	-	122,283	5,951
16	Total Distribution Substations & Equipment		2,220,032	1,053,219	490,566	7,772	652,330	16,145
17	Distribution Storage Battery Equipment (363)							
18	LVD V3 Distribution Batteries (Shared: V3,4)	230	6,195	3,357	1,564	25	1,244	5
19	Total Distribution Battery Equipment		6,195	3,357	1,564	25	1,244	5
20	Distribution Overhead System (364/365)							
21	HVD (Voltage 1) OH Lines (Shared V1,3,4)	125	9,178	4,659	2,170	34	2,281	35
24	HVD (Voltage 2) OH Lines (Shared V2,3,4)	122	458,705	231,680	107,911	1,710	114,304	3,100
25	HVD (Voltage 2) OH Lines (Shared V3,4)	230	521,384	282,581	131,620	2,085	104,691	406
26	HVD (Voltage 2) OH Lines (V2 Only)	124	32,153	-	-	-	30,661	1,492
27	LVD Primary (Multi-Phase)	230	1,599,780	867,054	403,855	6,398	321,228	1,246
28	LVD Primary (Single Phase)	235	3,105,456	2,108,028	981,873	15,555	-	-
29	LVD Secondary	231	961,022	652,356	303,853	4,814	-	-
30	Total Distribution Overhead System		6,743,986	4,165,284	1,940,097	30,735	600,541	7,328
31	Distribution Underground System (366/367)							
32	HVD (Voltage 1) UG Lines (V1 Only)	123	15,027	-	-	-	14,308	719
36	LVD Primary (Multi-Phase)	230	246,597	133,651	62,252	986	49,515	192
37	LVD Primary (Single Phase)	235	825,564	560,405	261,024	4,135	-	-
38	LVD Secondary	231	163,631	111,075	51,736	820	-	-
39	Total Distribution Underground System		1,268,339	814,325	379,295	6,009	67,742	968
40	Distribution Line Equipment (368)							
41	LVD Primary	230	132,672	71,906	33,492	531	26,640	103
42	LVD Secondary	231	1,239,436	841,347	391,881	6,208	-	-
43	Total Distribution Line Equipment		1,372,108	913,253	425,373	6,739	26,640	103
44	Distribution Services (369)							
45	Residential	260	1,094,643	1,094,643	-	-	-	-
46	Commercial & Industrial	261	68,380	-	68,380	-	-	-
47	Total Distribution Services		1,163,023	1,094,643	68,380	-	-	-

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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	818,321	492,395	234,218	439	90,961	307
3	Total Distribution Metering Equipment		818,321	492,395	234,218	439	90,961	307
4	Distribution Installations on Customer Premises (371)							
5	Streetlighting Installations	DIR	12,807	-	-	12,807	-	-
6	Total Distribution Installations on Customer Premises		12,807	0	0	12,807	0	0
7	Distribution Streetlighting Equipment (373)							
8	Luminaires/Suspensions/Poles/Transformers	DIR	215,771	-	-	215,771	-	-
9	Underground Cable & Conduits	233	9,571	-	-	9,571	-	-
10	Photoelectric Switches	233	7,012	-	-	7,012	-	-
11	Total Distribution Streetlighting Equipment		232,354	-	-	232,354	-	-
12	Total Distribution Plant in Service		14,018,474	8,629,653	3,582,892	297,567	1,482,660	25,702
13	Total Distribution Plant in Service	309	14,018,474	8,629,653	3,582,892	297,567	1,482,660	25,702
14	**Electric Plant Purchased & Sold**	220	0	0	0	0	0	0
15	**General, Common & Intangible Plant in Service**							
16	C&I Online Acct Management	502	447	274	106	3	62	1
17	MIMO EE/3.0 (U-20963 Order)	260	506	506	-	-	-	-
18	General, Common & Intangible	502	1,439,552	882,976	343,117	10,671	199,947	2,841
19	Total General, Common & Intangible Plant in Service		1,440,504	883,756	343,223	10,674	200,009	2,842

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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		1,829,448	895,065	438,541	5,160	483,656	7,026
3	Generation Step Ups		0	0	0	0	0	0
4	Total Production Depreciation Reserve		1,829,448	895,065	438,541	5,160	483,656	7,026
5	**Distribution Depreciation Reserve**							
6	Stations and Equipment		819,017	467,229	217,625	3,448	127,790	2,926
7	Overhead System		1,842,871	1,156,877	538,847	8,536	137,319	1,292
8	Underground System		365,329	235,960	109,905	1,741	17,534	189
9	Meters and Svc Drops		873,081	736,423	105,770	4,078	26,720	90
10	St Lgts and OPL		90,044	-	-	90,044	-	-
11	Total Distribution Depreciation Reserve		3,990,342	2,596,488	972,147	107,847	309,363	4,496
12	**Total General, Common & Intangible Depreciation Reserve**		830,853	509,710	197,978	6,157	115,369	1,639
13	**Total Depreciation Reserve**		6,650,643	4,001,263	1,608,666	119,164	908,389	13,162

DEPRECIATION RESERVE (PRODUCTION & TRANSMISSION)

1	**Production Depreciation Reserve**							
2	Fossil (Production-Steam)	220	451,552	220,924	108,242	1,274	119,378	1,734
3	Demand Response	220	5,479	2,680	1,313	15	1,448	21
4	Hydro	220	660,483	323,144	158,326	1,863	174,614	2,536
5	Other Production	220	711,934	348,317	170,659	2,008	188,216	2,734
6	Solar	220	0	0	0	0	0	0
7	Total Production Depreciation Reserve		1,829,448	895,065	438,541	5,160	483,656	7,026

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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	301	143	67	1	88	2
4	HVD (Voltage 1) Other Land & ROW	127	1,225	584	272	4	357	8
5	HVD (Voltage 2) Substation Land & ROW	122	320	162	75	1	80	2
6	HVD (Voltage 2) Other Land & ROW	122	15,667	7,913	3,686	58	3,904	106
7	LVD Land & ROW	230	13,809	7,484	3,486	55	2,773	11
8	Total Distribution Land & ROW Depreciation Reserve		31,322	16,286	7,586	120	7,202	129
9	Distribution Substations & Equipment (361/362)							
10	HVD (Voltage 1) Bulk Power Substations (Shared V2,3,4)	122	104,288	52,673	24,534	389	25,988	705
11	HVD (Voltage 1) Distribution Substations (Shared V3,4)	230	75,619	40,984	19,089	302	15,184	59
14	HVD (Voltage 1) Substations (V1 Only)	123	17,982	-	-	-	17,122	860
15	HVD (Voltage 2) Bulk Power Substations (Shared V2,3,4)	122	5,820	2,939	1,369	22	1,450	39
16	HVD (Voltage 2) Substations (V2 Only)	124	21,030	-	-	-	20,054	976
17	Total Distribution, Substations & Equipment Depreciation Reserve		385,504	183,729	85,577	1,356	112,079	2,764
17	Distribution Storage Battery Equipment (363)							
18	Batteries: LVD (Voltage 3)	230	3,865	2,095	976	15	776	3
19	Total Distribution Battery Equipment		3,865	2,095	976	15	776	3
20	Distribution Overhead System (364/365)		-	-	-	-	-	-
21	HVD (Voltage 1) OH Lines (Shared V1,3,4)	125	1,430	726	338	5	355	5
22	HVD (Voltage 1) OH Lines (Shared V3,4)	230	5,750	3,116	1,451	23	1,155	4
23	HVD (Voltage 1) OH Lines (V1 Only)	123	3,416	-	-	-	3,253	163
24	HVD (Voltage 2) OH Lines (Shared V2,3,4)	122	68,457	34,576	16,105	255	17,059	463
25	HVD (Voltage 2) OH Lines (Shared V3,4)	230	77,292	41,891	19,512	309	15,520	60
26	HVD (Voltage 2) OH Lines (V2 Only)	124	4,868	-	-	-	4,643	226
27	LVD	305	1,681,658	1,076,568	501,441	7,944	95,335	370
28	Total Distribution Overhead System Depreciation Reserve		1,842,871	1,156,877	538,847	8,536	137,319	1,292
29	Distribution Underground System (366/367)							
30	HVD (Voltage 1) UG Lines (V1 Only)	123	2,577	-	-	-	2,454	123
31	HVD (Voltage 2) UG Lines (Shared V2,3,4)	122	1,091	551	257	4	272	7
32	HVD (Voltage 2) UG Lines (Shared V3,4)	230	1,859	1,008	469	7	373	1
33	HVD (Voltage 2) UG Lines (V2 Only)	124	20	-	-	-	19	1
34	LVD	308	359,782	234,402	109,179	1,730	14,416	56
35	Total Distribution Underground System Depreciation Reserve		365,329	235,960	109,905	1,741	17,534	189
36	Distribution Line Equipment (368)							
37	Capacitors/Regulators/Transformers	312	398,325	265,119	123,486	1,956	7,734	30
38	Total Distribution Line Equipment Depreciation Reserve		398,325	265,119	123,486	1,956	7,734	30
39	Distribution Services (369)							
40	C&I and Residential Services	310	628,746	591,779	36,967	-	-	-
41	Total Distribution Services Depreciation Reserve		628,746	591,779	36,967	-	-	-

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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	240,387	144,644	68,803	129	26,720	90
3	Total Distribution Metering Equpment Depreciation Reserve		240,387	144,644	68,803	129	26,720	90
4	Distribution Installations on Customer Premises (371)							
5	Streetlighting Installations	DIR	3,949	-	-	3,949	-	-
6	Total Distribution Installations on Customer Premises Depreciation Reserve		3,949	0	0	3,949	0	0
7	Distribution Streetlighting Equipment (373)							
8	Streetlighting Equipment	311	90,044	-	-	90,044	-	-
9	Total Distribution Streetlighting Depreciation Reserve		90,044	-	-	90,044	-	-
10	Total Distribution Depreciation Reserve		3,990,342	2,596,488	972,147	107,847	309,363	4,496
11	Total Distribution Depreciation Reserve	317	3,990,342	2,596,488	972,147	107,847	309,363	4,496
12	**General, Common & Intangible Depreciation Reserve**							
13	C&I Online Acct Management	502	45	27	11	0	6	0
14	MIMO EE/3.0 (U-20963 Order)	260	235	235	-	-	-	-
0	Intangible Amortization Reserve	502	0	0	0	0	0	0
15	General, Common & Intangible	502	830,574	509,448	197,967	6,157	115,363	1,639
16	Total General, Common & Intangible Depreciation Reserve		830,853	509,710	197,978	6,157	115,369	1,639

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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	178,717	87,438	42,841	504	47,248	686
3	Total Production CWIP		178,717	87,438	42,841	504	47,248	686
4	**Distribution CWIP**							
5	HVD (Voltage 1)	127	22,911	10,916	5,085	81	6,684	146
6	HVD (Voltage 2)	122	44,024	22,235	10,357	164	10,970	297
7	LVD Distribution	306	200,323	129,255	60,204	954	9,871	38
8	Total Distribution CWIP		267,258	162,407	75,646	1,198	27,525	482
9	**General/Common/Intangible CWIP**							
10	Plant Held for Future Use	502	0	0	0	0	0	0
11	General, Common & Intangible	502	132,835	81,477	31,661	985	18,450	262
12	Total General, Common & Intangible CWIP		132,835	81,477	31,661	985	18,450	262

WORKING CAPITAL

1	**Current Assets**							
2	Cash & Cash Equivalents	316	50,385	30,003	12,683	868	6,722	109
3	Accts Receivable	143	280,141	146,114	69,719	2,509	61,593	206
4	Material and Supplies	316	216,848	129,128	54,585	3,738	28,929	469
5	Fuel Stock	100	64,489	27,589	15,342	355	20,845	359
6	Deferred Taxes	316	272,280	162,136	68,538	4,693	36,324	588
7	Other Cur Assets	502	1,263,051	774,716	301,048	9,362	175,432	2,493
8	Deferred Debits	502	842,494	516,760	200,808	6,245	117,019	1,663
9	1/ Karn & Campbell Regulatory Assets	220	143,378	70,148	34,369	404	37,905	551
10	PMF Regulatory Asset	143	3,990	2,081	993	36	877	3
11	PMD Regulatory Asset	143	8,216	4,285	2,045	74	1,806	6
12	Total Current Assets		3,145,271	1,862,960	760,129	28,284	487,452	6,446
13	**Current Liabilities**							
14	Accounts Payable	316	474,206	282,379	119,367	8,173	63,262	1,025
15	Customer Deposits	143	22,955	11,973	5,713	206	5,047	17
16	Dividends Payable	316	24,539	14,612	6,177	423	3,274	53
17	Accrued Interest	316	66,062	39,339	16,629	1,139	8,813	143
18	Accrued Taxes - Federal	502	2,331	1,430	556	17	324	5
19	Accrued Taxes - State	601	649	393	159	8	88	1
20	Accrued Taxes - R&PP & Other	316	253,100	150,715	63,710	4,362	33,765	547
21	Other Current Liabilities	502	72,728	44,609	17,335	539	10,102	144
22	Deferred CR	502	102,814	63,063	24,506	762	14,280	203
23	Total Current Liabilities		1,019,384	608,512	254,150	15,629	138,955	2,137
24	**Total Working Capital**		2,125,887	1,254,448	505,979	12,654	348,496	4,309

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	309	28,060	17,273	7,172	596	2,968	51
6	Customer Advances- Voltage 2 Customers	309	5,196	3,199	1,328	110	550	10
7	Customer Advances- LVD Customers	309	33,217	20,448	8,490	705	3,513	61
8	Total Deductions		66,473	40,920	16,989	1,411	7,030	122
9	**Total Adjustments to Rate Base**		(66,473)	(40,920)	(16,989)	(1,411)	(7,030)	(122)

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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							
3	Revenue From Electric Sales	DIR	2,429,573	1,475,923	635,100	28,433	286,819	3,298
4	Provision for Rate Refund	DIR	0	-	-	-	-	-
0	Unbilled Revenue	DIR	0	-	-	-	-	-
4	Total Non PSCR Rate Revenue		2,429,573	1,475,923	635,100	28,433	286,819	3,298
5	PSCR Base Revenue	DIR	2,004,517	845,483	470,163	10,879	677,992	-
6	Unbilled PSCR Base Revenue	DIR	0	-	-	-	-	-
7	Total PSCR Rate Revenue		2,004,517	845,483	470,163	10,879	677,992	-
8	Total Rate Revenue		4,434,089	2,321,406	1,105,262	39,312	964,811	3,298
10	**Non-PSCR Rate Revenue Credits**							
11	450 Late Payment Charge Revenue	DIR	9,623	5,915	2,545	-	1,149	13
12	451 Miscellaneous Service & Reconnect Fees	253	1,056	488	279	6	282	1
13	454 Pole Rental Rev	307	12,965	8,625	3,293	50	985	12
14	454 Other Rents	316	2,029	1,255	516	41	212	4
15	456 Purchased Power Administrative Fees	100	642	274	153	4	207	4
16	Other Revenues	150	10,486	3,935	2,247	51	4,199	54
17	Job Work Revenue	414	1,663	1,085	416	17	143	2
18	LEDR & LTILRR: Production	DIR	212,169	95,397	49,152	1,105	65,371	1,144
19	LEDR & LTILRR: Delivery	390	11,576	7,075	2,979	197	1,302	23
20	Non PSCR Revenue Credits		262,208	124,050	61,581	1,470	73,851	1,256
22	PSCR Factor Revenue	DIR	284,114	119,836	66,639	1,542	96,097	-
23	Unbilled PSCR Factor Revenue	DIR	0	-	-	-	-	-
24	Intersystem Sales	220	24,609	12,040	5,899	69	6,506	95
25	GSG and GI Market Price Revenue	DIR	15,603	-	-	-	-	15,603
26	PSCR Revenue Credits		324,326	131,876	72,538	1,611	102,603	15,698
27	Total Revenue Credits		586,534	255,926	134,119	3,082	176,454	16,953
28	Total Revenue		5,020,623	2,577,332	1,239,381	42,393	1,141,265	20,252

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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	87,893	35,557	22,347	325	29,234	429
3	On-Peak Winter Fuel for Gen	105	190,669	75,957	47,813	875	65,207	817
4	Off-Peak Summer Fuel for Gen	104	83,800	37,717	18,532	515	26,419	617
5	Off-Peak Winter Fuel for Gen	106	150,867	67,423	32,900	1,106	48,450	988
6	Critical Summer Peak Energy	107	35,120	15,378	9,003	90	10,540	109
7	Total Fuel Expense		548,348	232,032	130,596	2,911	179,851	2,959
	Purchased & Interchange Power Expense							
9	Mid-Peak Summer Purchased Power	108	122,921	49,728	31,254	455	40,885	600
10	On-Peak Winter Purchased Power	105	266,658	106,228	66,869	1,224	91,195	1,142
11	Off-Peak Summer Purchased Power	104	117,198	52,749	25,918	720	36,948	863
12	Off-Peak Winter Purchased Power	106	210,993	94,294	46,012	1,547	67,759	1,382
13	Critical Peak Summer Purchased Power	107	49,117	21,507	12,591	126	14,741	152
14	Purchased Power Capacity: Capacity Costs	121	0	0	0	0	0	0
15	Purchased Power Capacity: Other	220	366,140	179,136	87,768	1,033	96,798	1,406
16	Total Purchased & Interchange Power Expense		1,133,028	503,642	270,412	5,104	348,326	5,544
17	Total Fuel and Purchased & Interchange Power Expense		1,681,377	735,673	401,007	8,016	528,177	8,503

PRODUCTION O&M (2)

1	Fossil Plant O&M Expense							
2	Capacity Related Operations	220	39,714	19,430	9,520	112	10,499	153
3	Capacity Related Maintenance	220	5,484	2,683	1,314	15	1,450	21
4	Energy Related Operations	100	(10,263)	(4,390)	(2,441)	(56)	(3,317)	(57)
5	Energy Related Maintenance	100	12,765	5,461	3,037	70	4,126	71
6	Capacity Related Fuel Handling	220	0	0	0	0	0	0
7	Energy Related Fuel Handling	100	7,555	3,232	1,797	42	2,442	42
8	Total Fossil O&M Expense		55,255	26,416	13,227	183	15,200	230
9	Hydro Plant O&M Expense							
10	Capacity Related Operations	220	7,234	3,539	1,734	20	1,913	28
11	Capacity Related Maintenance	220	2,593	1,269	622	7	686	10
12	Energy Related Operations	100	(607)	(260)	(144)	(3)	(196)	(3)
13	Energy Related Maintenance	100	3,988	1,706	949	22	1,289	22
14	Total Hydro O&M Total		13,209	6,255	3,160	46	3,691	57
15	Other Power Generation O&M Expense							
16	Capacity Related Operations & Maintenance	220	64,631	31,621	15,493	182	17,087	248
17	Energy Related Operations & Maintenance	100	0	0	0	0	0	0
18	Total Other Power Gen O&M Expense		64,631	31,621	15,493	182	17,087	248
19	Other Power Supply Expense							
20	Capacity Related Operations & Maintenance	220	5,268	2,578	1,263	15	1,393	20
21	Energy Related Operations & Maintenance	100	0	0	0	0	0	0
22	Total Other Power Supply O&M Expense		5,268	2,578	1,263	15	1,393	20
23	Disposition of Allowances	220	0	0	0	0	0	0
24	**Total Production O&M (excluding Fuel and P&I)**		138,363	66,869	33,143	426	37,370	555
25	**Total Production O&M Expense**		1,819,739	802,542	434,150	8,442	565,547	9,058

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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	631,863	297,311	151,998	2,017	178,174	2,363
3	Total Transmission O&M Expense		631,863	297,311	151,998	2,017	178,174	2,363

DISTRIBUTION O&M

1	**Distribution Operation Expense**							
2	580 Supv & Engineering - Distribution (LVD)	400	31,980	21,209	7,789	883	2,072	27
3	580 Supv & Engineering - HVD (Voltage 1)	402	354	168	78	1	104	3
4	580 Supv & Engineering - HVD (Voltage 2)	404	665	331	154	2	174	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	411	193	90	1	124	4
8	582 Station Expense - HVD (Voltage 2)	304	437	210	98	2	125	3
9	583 Overhead Expense - Distribution (LVD)	307	55,422	36,868	14,078	215	4,209	51
10	583 Overhead Expense - HVD (Voltage 1)	121	61	31	15	0	15	0
11	583 Overhead Expense - HVD (Voltage 2)	122	948	479	223	4	236	6
12	584 Underground Lines- Distribution (LVD)	308	8,708	5,673	2,642	42	349	1
13	584 Underground Lines- HVD (Voltage 1)	321	34	-	-	-	32	2
14	584 Underground Lines- HVD (Voltage 2)	322	40	21	10	0	9	0
15	585 Street Lighting & Signal System	311	1,594	-	-	1,594	-	-
16	586 Metering Expense	313	(3,700)	(2,227)	(1,059)	(2)	(411)	(1)
17	587 Customer Installations	160	4,675	4,097	555	14	10	0
18	588 Miscellaneous	400	24,934	16,536	6,073	688	1,615	21
19	589 Rents	309	3,121	1,921	798	66	330	6
20	Total Distribution Operation Expense		129,682	85,509	31,542	3,510	8,994	127
21	Distribution Maintenance Expense							
22	590 Supv & Engineering - Distribution (LVD)	401	3,870	2,570	986	16	295	4
23	590 Supv & Engineering - HVD (Voltage 1)	403	274	129	60	1	81	2
24	590 Supv & Engineering - HVD (Voltage 2)	405	514	254	119	2	136	3
25	591 Structures - Distribution (LVD)	230	0	0	0	0	0	0
26	591 Structures - HVD (Voltage 1)	303	362	169	79	1	109	3
27	591 Structures - HVD (Voltage 2)	304	385	185	86	1	110	2
28	592 Station Equipment - Distribution (LVD)	230	0	0	0	0	0	0
29	592 Station Equipment - HVD (Voltage 1)	303	7,352	3,443	1,604	25	2,217	63
30	592 Station Equipment - HVD (Voltage 2)	304	7,816	3,753	1,748	28	2,240	47
31	593 Overhead Lines - Distribution (LVD)	307	319,492	212,534	81,155	1,242	24,266	296
32	593 Overhead Lines - HVD (Voltage 1)	121	752	383	181	1	184	2
33	593 Overhead Lines - HVD (Voltage 2)	122	11,621	5,869	2,734	43	2,896	79
34	594 Underground Lines- Distribution (LVD)	308	2,170	1,414	658	10	87	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	233	155	72	1	5	0
38	596 Street Lighting & Signal System	311	89	-	-	89	-	-
39	597 Meters	313	4,413	2,656	1,263	2	491	2
40	598 Miscellaneous	401	(70)	(46)	(18)	(0)	(5)	(0)
41	Total Distribution Maintenance Expense		359,273	233,468	90,727	1,464	33,110	504
42	**Total Distribution O&M Expense**		488,955	318,977	122,269	4,975	42,104	631

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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	3,606	2,696	597	16	296	1
3	902 Meter Reading	263	11,010	9,695	1,313	2	-	-
4	903 Rcrds & Collection	160	24,898	21,818	2,954	72	54	0
5	904 Uncollectibles	143	20,274	10,490	5,036	176	4,559	14
6	905 Misc Expenses	408	0	0	0	0	0	0
7	Total Customer Accounts		59,788	44,699	9,899	266	4,909	15
8	**Customer Services Expense**							
9	907 Supervision	160	(0)	(0)	(0)	(0)	(0)	(0)
10	908 Customer Assist	603	3,900	1,464	836	19	1,562	20
11	909 Info & Inst	160	3,258	2,855	387	9	7	0
12	910 Miscellaneous	160	0	0	0	0	0	0
13	Total Customer Services		7,158	4,319	1,222	28	1,569	20
14	**Other Expense**							
15	911-916 Sales Expense	160	72	63	9	0	0	0
16	Customer Contact Center (CCC)	161	14,613	13,672	941	-	-	-
17	Business Customer Care (BCC)	162	1,817	-	1,671	83	62	0
18	Multi Acct Mgmt Project (Formerly C&I Online Acct Mgmt)	502	185	114	44	1	26	0
19	Total Other Expense		16,687	13,849	2,665	85	88	1
20	**Administrative & General Expense**							
21	Production	500	26,519	12,975	6,357	75	7,011	102
22	HV Distribution	406	4,497	2,195	1,023	16	1,232	31
23	Distribution	407	53,360	35,441	13,426	564	3,882	47
24	Customer	409	9,623	7,046	1,599	42	931	5
25	Total Administrative & General Expense		94,000	57,657	22,405	697	13,056	186
26	**Total O&M Expense (excluding PSCR Expense)**		804,952	506,369	191,604	6,477	99,096	1,406
27	Test Year Other O&M Expense	443	0	-	0	0	0	0
27	**Total O&M Expense**		3,118,192	1,539,354	744,609	16,509	805,447	12,273

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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		305,550	149,491	73,244	862	80,779	1,173
3	Total Production		305,550	149,491	73,244	862	80,779	1,173
4	**Distribution**							
5	Stations and Equipment		91,148	50,543	23,542	373	16,306	384
6	Overhead System		199,868	123,733	57,632	913	17,383	206
7	Underground System		29,284	18,699	8,709	138	1,709	29
8	Meters and Svc Drops		88,004	65,478	16,421	573	5,513	19
9	St Lgts and OPL		10,207	-	-	10,207	-	-
11	Total Distribution		418,510	258,453	106,305	12,203	40,911	638
12	**General/Common/Intangible**							
13	General, Common & Intangible		83,508	51,221	19,904	619	11,599	165
14	Test Year Gen/Comm/Int Change	445	0	0	0	0	0	0
15	Total General/Common/Intangible Dep Expense		83,508	51,221	19,904	619	11,599	165
16	**Other Amortization Expense**		5,520	2,879	1,374	49	1,214	4
17	**Total Depreciation & Amortization Expense**		813,088	462,045	200,827	13,734	134,503	1,980

DEPRECIATION EXPENSE (PRODUCTION & TRANSMISSION)

1	**Production Depreciation Expense**							
2	Fossil (Production-Steam)	220	191,760	93,819	45,967	541	50,696	736
3	Demand Response	220	2,806	1,373	673	8	742	11
4	Hydro	220	63,954	31,290	15,330	180	16,908	246
5	Other Production	220	47,030	23,010	11,274	133	12,433	181
6	Solar	220	0	0	0	0	0	0
7	Total Production Depreciation Expense		305,550	149,491	73,244	862	80,779	1,173

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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	196	94	44	1	57	1
4	HVD (Voltage 1) Other Land & ROW	127	61	29	14	0	18	0
5	HVD (Voltage 2) Substation Land & ROW	122	209	105	49	1	52	1
6	HVD (Voltage 2) Other Land & ROW	122	785	397	185	3	196	5
7	LVD Land & ROW	230	790	428	199	3	159	1
8	Total Distribution Land & ROW Depreciation Expense		2,042	1,053	490	8	482	9
9	Distribution Substations & Equipment (361/362)							
10	HVD (Voltage 1) Bulk Power Substations (Shared V2,3,4)	122	12,208	6,166	2,872	45	3,042	82
11	HVD (Voltage 1) Distribution Substations (Shared V3,4)	230	9,909	5,370	2,501	40	1,990	8
12	HVD (Voltage 1) Substations (V1 Only)	123	2,533	-	-	-	2,412	121
13	HVD (Voltage 2) Bulk Power Substations (Shared V2,3,4)	122	769	389	181	3	192	5
14	HVD (Voltage 2) Distribution Substations (Shared V3,4)	124	22,648	12,275	5,717	91	4,548	18
15	HVD (Voltage 2) Substations (V2 Only)	124	2,959	-	-	-	2,822	137
16	Total Distribution Substations & Equipment Depreciation Expense		51,026	24,200	11,272	179	15,005	372
			-	-	-	-	-	-
17	Distribution Storage Battery Equipment (363)		-	-	-	-	-	-
18	Batteries: LVD (Voltage 3)	230	442	240	112	2	89	0
19	Total Distribution Battery Equipment		442	240	112	2	89	0
20	Distribution Overhead System (364/365)							
21	HVD (Voltage 1) OH Lines (Shared V1,3,4)	125	245	125	58	1	61	1
22	HVD (Voltage 1) OH Lines (Shared V3,4)	230	938	509	237	4	188	1
23	HVD (Voltage 1) OH Lines (V1 Only)	123	609	-	-	-	579	29
24	HVD (Voltage 2) OH Lines (Shared V2,3,4)	122	12,659	6,394	2,978	47	3,154	86
25	HVD (Voltage 2) OH Lines (Shared V3,4)	230	14,488	7,852	3,657	58	2,909	11
26	HVD (Voltage 2) OH Lines (V2 Only)	124	893	-	-	-	851	41
27	LVD	305	170,035	108,854	50,702	803	9,640	37
28	Total Distribution Overhead Depreciation Expense		199,868	123,733	57,632	913	17,383	206
29	Distribution Underground System (366/367)							
30	HVD (Voltage 1) UG Lines (V1 Only)	123	471	-	-	-	449	23
31	HVD (Voltage 2) UG Lines (Shared V2,3,4)	122	215	108	50	1	53	1
32	HVD (Voltage 2) UG Lines (Shared V3,4)	230	358	194	90	1	72	0
33	HVD (Voltage 2) UG Lines (V2 Only)	124	4	-	-	-	3	0
34	LVD	308	28,236	18,396	8,568	136	1,131	4
35	Total Distribution Underground Depreciation Expense		29,284	18,699	8,709	138	1,709	29
36	Distribution Line Equipment (368)							
37	Line Equipment	312	37,638	25,051	11,668	185	731	3
38	Total Distribution Line Equipment Depreciation Expense		37,638	25,051	11,668	185	731	3
39	Distribution Services (369)							
40	Overhead & Underground Services	310	37,862	35,636	2,226	-	-	-
41	Total Distribution Services Depreciation Expense		37,862	35,636	2,226	-	-	-

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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 (cont.)**							
2	Distribution Metering Equipment (370)		-	-	-	-	-	-
3	Metering Equipment	170	49,596	29,843	14,195	27	5,513	19
4	Total Distribution Metering Equipment Depreciation Expense		49,596	29,843	14,195	27	5,513	19
5	Distribution Installations on Customer Premises (371)		-	-	-	-	-	-
6	Streetlighting Installations	DIR	546	-	-	546	-	-
7	Total Distribution Installations on Customer Premises		546	0	0	546	0	0
8	Distribution Streetlighting Equipment Depreciation Expense (373)	311	10,207	-	-	10,207	-	-
9	**Total Distribution Depreciation Expense**		418,510	258,453	106,305	12,203	40,911	638
10	**General/Common/Intangible**							
11	C&I Online Account Management	502	89	55	21	1	12	0
12	MIMO EE/3.0 (U-20963 Order)	502	101	62	24	1	14	0
13	General, Common & Intangible	502	83,318	51,105	19,859	618	11,572	164
14	Total Gen/Comm/Int Depreciation Expense		83,508	51,221	19,904	619	11,599	165
15	**Other Amortization**							
16	PMF Amortization	143	1,782	929	443	16	392	1
17	PMD Amortization	143	3,738	1,950	930	33	822	3
18	Total Other Amortization Expense		5,520	2,879	1,374	49	1,214	4
19	**Total Depreciation & Amortization Expense**		813,088	462,045	200,827	13,734	134,503	1,980

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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	1,150	432	246	6	461	6
2	State Income Tax	439	33,324	17,049	9,100	462	6,489	224
	RP&P Tax							
4	R&PP Taxes - Prod	220	63,820	31,224	15,298	180	16,872	245
5	R&PP Taxes - HVD (Voltage 1)	301	18,780	8,574	3,993	63	5,972	178
6	R&PP Taxes - HVD (Voltage 2)	302	36,087	17,826	8,303	132	9,625	201
7	R&PP Taxes - LVD	306	137,118	88,473	41,209	653	6,757	26
8	R&PP Taxes - PHFFU	316	8	5	2	0	1	0
9	R&PP Taxes -General, Common & Intangible	502	24,688	15,143	5,884	183	3,429	49
10	Total R&PP Taxes		280,500	161,245	74,690	1,211	42,656	699
11	Payroll and Miscellaneous Tax							
12	Payroll Related Taxes	502	25,343	15,544	6,040	188	3,520	50
13	Total Payroll/Miscellaneous Taxes		25,343	15,544	6,040	188	3,520	50
14	Other Taxes	150	11,296	4,239	2,421	55	4,523	58
15	Total Other Taxes		351,612	198,508	92,497	1,921	57,649	1,037
16	Federal Income Tax	439	46,009	23,538	12,563	638	8,960	309
17	Total Taxes Other Than Income		318,289	181,460	83,398	1,459	51,160	812
18	Total Income Taxes		79,333	40,587	21,663	1,100	15,449	534
19	**Total Taxes**		397,622	222,047	105,061	2,559	66,609	1,346

INCOME STATEMENT ADJUSTMENTS

1	**Other Adjustments to the Income Statement**							
2	AFUDC	330	16,026	9,174	4,157	74	2,581	40
3	**Total Other Adjustments**		16,026	9,174	4,157	74	2,581	40

ADDITIONAL REVENUE REQUIREMENTS

1	**Additional Revenue Requirements**							
2	Campbell Rev Req Adjustment	220	77,486	37,910	18,574	219	20,485	298

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Projected 12-Month Period Ending April 30, 2027
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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	**Rate Base**	15,367,518	9,032,482	3,908,082	215,410	2,178,066	33,477
2	**Revenue**						
3	Total Rate Revenue	4,434,089	2,321,406	1,105,262	39,312	964,811	3,298
4	Total Revenue Credits	586,534	256,020	134,135	3,083	176,346	16,950
5	Total Revenue	5,020,623	2,577,426	1,239,398	42,395	1,141,157	20,248
6	**Expenses:**						
7	Fuel and P&I Expense	1,681,377	735,673	401,007	8,016	528,177	8,503
8	Transmission Expense	631,863	297,311	151,998	2,017	178,174	2,363
9	Other O & M Expense	804,952	518,685	193,164	6,493	85,571	1,040
10	Depreciation & Amortization Expense	813,088	463,194	200,972	13,735	133,242	1,945
11	Other Taxes	351,612	198,589	92,507	1,921	57,561	1,034
12	Federal Income Taxes	46,009	22,699	12,458	637	9,881	334
13	Total Expenses	4,328,901	2,236,152	1,052,105	32,819	992,605	15,220
14	Net Operating Income	691,722	341,274	187,292	9,576	148,551	5,028
15	Other Income Adjustments	16,026	9,224	4,164	74	2,526	38
16	Adjusted Net Operating Income	707,748	350,499	191,456	9,651	151,077	5,066
17	Return on Rate Base @ 6.35%	975,589	573,417	248,100	13,675	138,272	2,125
18	Income Deficiency (Sufficiency)	267,840	222,918	56,644	4,025	(12,805)	(2,941)
19	Revenue Deficiency (Sufficiency)	358,392	298,282	75,794	5,385	(17,134)	(3,935)
20	Additional Rev Requirement	77,486	37,910	18,574	219	20,485	298
21	Total Revenue Deficiency (Sufficiency)	435,877	336,192	94,369	5,604	3,351	(3,638)
22	Revenue Requirement/Total Cost of Service	5,456,501	2,913,618	1,333,766	47,998	1,144,508	16,610
23	Less: Revenue Credits	586,534	256,020	134,135	3,083	176,346	16,950
24	**Proposed Rate Design Revenue**	**4,869,967**	**2,657,598**	**1,199,631**	**44,915**	**968,162**	**(339)**
25	Production: Net Capacity Cost	417,794	212,965	100,403	805	102,257	1,364
26	Production: Capacity Related Cost Offset	800,952	384,659	191,446	2,551	219,627	2,669
27	Production: Non-Capacity Related Cost	1,415,735	628,094	344,633	6,344	443,985	(7,321)
28	Distribution: Demand Related Cost	1,978,181	1,237,733	516,610	33,702	187,300	2,836
29	Distribution: Customer Related Cost	257,305	194,147	46,539	1,513	14,993	113
30	Full Service MWH Sales	30,248,550	12,685,410	7,054,196	163,223	10,172,419	173,301
31	ROA MWH Sales	3,552,623	-	189,639	-	3,362,984	-
32	MWH Sales	33,801,173	12,685,410	7,243,836	163,223	13,535,403	173,301
33	Customers	1,918,106	1,680,798	227,572	5,560	4,163	14

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**	9,032,482	9,032,482	2,449,933	1,458,149	3,908,082	7,983	179,938	27,490	215,410
2	**Revenue**									
3	Total Rate Revenue	2,321,406	2,321,406	684,767	420,495	1,105,262	1,521	28,047	9,744	39,312
4	Total Revenue Credits	256,020	256,020	79,128	55,007	134,135	201	1,168	1,715	3,083
5	Total Revenue	2,577,426	2,577,426	763,895	475,502	1,239,398	1,721	29,214	11,459	42,395
6	**Expenses:**									
7	Fuel and P&I Expense	735,673	735,673	236,726	164,281	401,007	482	2,441	5,093	8,016
8	Transmission Expense	297,311	297,311	91,856	60,142	151,998	111	429	1,476	2,017
9	Other O & M Expense	518,685	518,685	122,399	70,765	193,164	334	4,775	1,384	6,493
10	Depreciation & Amortization Expense	463,194	463,194	126,711	74,261	200,972	396	11,872	1,467	13,735
11	Other Taxes	198,589	198,589	57,121	35,386	92,507	137	1,088	696	1,921
12	Federal Income Taxes	22,699	22,699	8,050	4,407	12,458	16	537	84	637
13	Total Expenses	2,236,152	2,236,152	642,864	409,242	1,052,105	1,476	21,143	10,200	32,819
14	Net Operating Income	341,274	341,274	121,032	66,260	187,292	245	8,072	1,259	9,576
15	Other Income Adjustments	9,224	9,224	2,563	1,601	4,164	6	37	32	74
16	Adjusted Net Operating Income	350,499	350,499	123,595	67,861	191,456	251	8,108	1,291	9,651
17	Return on Rate Base @ 6.35%	573,417	573,417	155,531	92,569	248,100	507	11,423	1,745	13,675
18	Income Deficiency (Sufficiency)	222,918	222,918	31,936	24,708	56,644	256	3,315	454	4,025
19	Revenue Deficiency (Sufficiency)	298,282	298,282	42,733	33,061	75,794	342	4,435	607	5,385
20	Additional Rev Requirement	37,910	37,910	11,235	7,339	18,574	7	36	175	219
21	Total Revenue Deficiency (Sufficiency)	336,192	336,192	53,968	40,400	94,369	350	4,471	783	5,604
22	Revenue Requirement/Total Cost of Service	2,913,618	2,913,618	817,864	515,902	1,333,766	2,071	33,686	12,242	47,998
23	Less: Revenue Credits	256,020	256,020	79,128	55,007	134,135	201	1,168	1,715	3,083
24	**Proposed Rate Design Revenue**	**2,657,598**	**2,657,598**	**738,736**	**460,895**	**1,199,631**	**1,870**	**32,518**	**10,527**	**44,915**
25	Production: Net Capacity Cost	212,965	212,965	61,392	39,011	100,403	3	-	801	805
26	Production: Capacity Related Cost Offset	384,659	384,659	115,432	76,014	191,446	105	494	1,952	2,551
27	Production: Non-Capacity Related Cost	628,094	628,094	204,672	139,961	344,633	380	1,819	4,145	6,344
28	Distribution: Demand Related Cost	1,237,733	1,237,733	320,106	196,504	516,610	1,303	28,856	3,544	33,702
29	Distribution: Customer Related Cost	194,147	194,147	37,135	9,404	46,539	79	1,349	85	1,513
30	Full Service MWH Sales	12,685,410	12,685,410	4,126,393	2,927,804	7,054,196	10,777	54,640	97,806	163,223
31	ROA MWH Sales	-	-	18,386	171,253	189,639	-	-	-	-
32	MWH Sales	12,685,410	12,685,410	4,144,779	3,099,057	7,243,836	10,777	54,640	97,806	163,223
33	Customers	1,680,798	1,680,798	206,948	20,624	227,572	399	4,696	465	5,560

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**	193,939	41,165	78,212	767,522	156,442	270,263	624,745	36,381	7,818	1,580	2,178,066
2	**Revenue**											
3	Total Rate Revenue	73,817	37,422	43,192	336,047	83,685	122,725	241,478	21,284	4,442	718	964,811
4	Total Revenue Credits	11,613	5,808	8,354	57,211	19,657	24,809	42,376	5,511	898	110	176,346
5	Total Revenue	85,431	43,230	51,545	393,258	103,342	147,534	283,854	26,795	5,340	828	1,141,157
6	**Expenses:**											
7	Fuel and P&I Expense	35,814	17,219	25,342	175,655	56,437	72,569	125,642	16,507	2,639	354	528,177
8	Transmission Expense	13,412	5,476	8,439	62,683	17,343	23,281	41,382	5,209	820	128	178,174
9	Other O & M Expense	7,335	1,806	2,810	31,889	5,884	8,553	25,370	1,587	274	63	85,571
10	Depreciation & Amortization Expense	11,728	3,220	5,298	47,189	10,719	15,752	35,862	2,885	500	88	133,242
11	Other Taxes	4,600	1,687	2,146	19,667	4,914	7,425	15,905	955	222	41	57,561
12	Federal Income Taxes	782	862	468	3,503	502	1,244	2,475	(22)	55	10	9,881
13	Total Expenses	73,671	30,270	44,503	340,586	95,799	128,825	246,636	27,122	4,510	683	992,605
14	Net Operating Income	11,760	12,960	7,042	52,672	7,542	18,710	37,217	(327)	830	144	148,551
15	Other Income Adjustments	210	55	97	915	176	301	710	50	9	2	2,526
16	Adjusted Net Operating Income	11,970	13,015	7,139	53,587	7,719	19,011	37,928	(277)	839	146	151,077
17	Return on Rate Base @ 6.35%	12,312	2,613	4,965	48,725	9,932	17,157	39,661	2,310	496	100	138,272
18	Income Deficiency (Sufficiency)	342	(10,402)	(2,174)	(4,862)	2,213	(1,853)	1,733	2,587	(343)	(46)	(12,805)
19	Revenue Deficiency (Sufficiency)	458	(13,918)	(2,909)	(6,505)	2,961	(2,480)	2,320	3,461	(459)	(61)	(17,134)
20	Additional Rev Requirement	1,554	628	956	7,251	1,813	2,563	5,051	570	88	12	20,485
21	Total Revenue Deficiency (Sufficiency)	2,012	(13,290)	(1,953)	745	4,774	83	7,370	4,031	(371)	(50)	3,351
22	Revenue Requirement/Total Cost of Service	87,443	29,940	49,593	394,003	108,116	147,617	291,224	30,826	4,969	778	1,144,508
23	Less: Revenue Credits	11,613	5,808	8,354	57,211	19,657	24,809	42,376	5,511	898	110	176,346
24	**Proposed Rate Design Revenue**	**75,830**	**24,132**	**41,239**	**336,793**	**88,459**	**122,808**	**248,848**	**25,315**	**4,071**	**668**	**968,162**
25	Production: Net Capacity Cost	8,184	2,990	4,660	37,195	8,363	12,328	25,472	2,621	392	52	102,257
26	Production: Capacity Related Cost Offset	16,511	4,645	10,121	77,872	19,874	27,681	54,850	6,867	1,061	146	219,627
27	Production: Non-Capacity Related Cost	31,046	14,175	21,311	150,289	46,743	60,435	103,713	13,757	2,190	325	443,985
28	Distribution: Demand Related Cost	17,026	2,172	4,671	66,158	12,812	21,356	60,611	1,971	391	132	187,300
29	Distribution: Customer Related Cost	3,062	149	477	5,280	666	1,008	4,203	99	36	14	14,993
30	Full Service MWH Sales	659,010	343,708	493,168	3,289,071	1,158,158	1,441,363	2,395,375	332,592	53,237	6,737	10,172,419
31	ROA MWH Sales	71,144	-	-	-	1,265,948	1,076,272	949,620	-	-	-	3,362,984
32	MWH Sales	730,153	343,708	493,168	3,289,071	2,424,106	2,517,636	3,344,995	332,592	53,237	6,737	13,535,403
33	Customers	1,420	21	80	1,413	36	98	1,077	5	7	5	4,163

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Line No.	(a) Description	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(g) Total Lighting & Unmetered	(f) Total Primary	(h) Rate GSG
1	**Net Plant**						
2	Production	2,260,789	1,106,100	541,939	6,377	597,691	8,682
3	Transmission	-	-	-	-	-	-
4	Distribution	10,295,898	6,195,814	2,686,503	190,920	1,200,971	21,690
5	General/Common/Intangible	751,416	471,335	180,338	5,582	92,989	1,172
6	Plant Purchased/Sold	0	0	0	0	0	0
7	Total Net Plant	13,308,103	7,773,249	3,408,780	202,879	1,891,651	31,545
8	**Working Capital**						
9	Total Current Assets	3,145,271	1,892,513	763,856	28,324	455,020	5,559
10	Total Current Liabilities	1,019,384	611,847	254,571	15,634	135,295	2,037
11	Total Working Capital	2,125,887	1,280,666	509,285	12,690	319,725	3,522
	Adjustments to Rate Base						
13	Additions to Rate Base	0	0	0	0	0	0
14	Deductions from Rate Base	66,473	21,433	9,983	158	33,310	1,589
15	Total Adjustments to Rate Base	(66,473)	(21,433)	(9,983)	(158)	(33,310)	(1,589)
16	**Total Rate Base**	**15,367,518**	**9,032,482**	**3,908,082**	**215,410**	**2,178,066**	**33,477**
17	**Production Expense**						
18	Fuel Expense	548,348	232,032	130,596	2,911	179,851	2,959
19	Purchased & Interchange Power Expense	1,133,028	503,642	270,412	5,104	348,326	5,544
20	Total Fuel and P&I Expense	1,681,377	735,673	401,007	8,016	528,177	8,503
21	Fossil O&M Exp	55,255	26,416	13,227	183	15,200	230
22	Nuclear O&M Exp	0	-	-	-	-	-
23	Hydro O&M Exp	13,209	6,255	3,160	46	3,691	57
23	Other Power Gen O&M Exp	64,631	31,621	15,493	182	17,087	248
24	Other Power Supply O&M Exp	5,268	2,578	1,263	15	1,393	20
25	Total Production O&M Expense	138,363	66,869	33,143	426	37,370	555
26	Total Production (Inc. Fuel and P&I) O&M Expense	1,819,739	802,542	434,150	8,442	565,547	9,058
27	**Transmission & Distribution Expense**						
28	Trans O&M Exp	631,863	297,311	151,998	2,017	178,174	2,363
29	Other O&M Adjustments	0	0	0	0	0	0
30	Distr Oper Exp	129,682	88,134	31,879	3,514	6,105	51
31	Distr Maint Exp	359,273	241,863	91,787	1,475	23,896	252
32	Total Transmission & Distribution O&M Expense	1,120,818	627,308	275,663	7,006	208,175	2,666
33	**Customer Related Expense**						
34	Customer Accounts Exp	59,788	44,699	9,899	266	4,909	15
35	Customer Service Exp	7,158	4,319	1,222	28	1,569	20
36	Other Customer Exp	16,687	13,851	2,666	85	85	1
37	Total Customer O&M Expense	83,634	62,869	13,787	379	6,563	36
38	**Admin & General Expense**	94,000	58,950	22,568	699	11,637	147
39	**Total O&M Expense**	**3,118,192**	**1,551,669**	**746,169**	**16,526**	**791,922**	**11,906**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

Projected 12-Month Period Ending April 30, 2027
Version 2
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b)	(c) Rate RS	(d) Total Residential	(e) Rate GS	(f) Rate GSD	(g) Commercial Secondary	(m) Rate GML	(n) Rate UUL	(o) Rate GU	(p) Total Lighting & Unmetered
1	**Net Plant**										
2	Production		1,106,100	1,106,100	327,807	214,132	541,939	219	1,041	5,116	6,377
3	Transmission		-	-	-	-	-	-	-	-	-
4	Distribution		6,195,814	6,195,814	1,696,573	989,930	2,686,503	6,800	167,074	17,046	190,920
5	General/Common/Intangible		471,335	471,335	113,473	66,865	180,338	283	3,971	1,328	5,582
6	Plant Purchased/Sold		0	0	0	0	0	0	0	0	0
7	Total Net Plant		7,773,249	7,773,249	2,137,853	1,270,927	3,408,780	7,301	172,086	23,491	202,879
8	**Working Capital**										
9	Total Current Assets		1,892,513	1,892,513	478,431	285,425	763,856	1,240	21,243	5,840	28,324
10	Total Current Liabilities		611,847	611,847	160,203	94,368	254,571	541	13,320	1,773	15,634
11	Total Working Capital		1,280,666	1,280,666	318,228	191,057	509,285	699	7,923	4,067	12,690
	Adjustments to Rate Base										
13	Additions to Rate Base		0	0	0	0	0	0	0	0	0
14	Deductions from Rate Base		21,433	21,433	6,148	3,835	9,983	18	72	68	158
15	Total Adjustments to Rate Base		(21,433)	(21,433)	(6,148)	(3,835)	(9,983)	(18)	(72)	(68)	(158)
16	**Total Rate Base**		**9,032,482**	**9,032,482**	**2,449,933**	**1,458,149**	**3,908,082**	**7,983**	**179,938**	**27,490**	**215,410**
17	**Production Expense**										
18	Fuel Expense		232,032	232,032	76,562	54,034	130,596	186	948	1,778	2,911
19	Purchased & Interchange Power Expense		503,642	503,642	160,164	110,247	270,412	296	1,494	3,315	5,104
20	Total Fuel and P&I Expense		735,673	735,673	236,726	164,281	401,007	482	2,441	5,093	8,016
21	Fossil O&M Exp		26,416	26,416	7,953	5,274	13,227	8	39	135	183
22	Nuclear O&M Exp		-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp		6,255	6,255	1,896	1,265	3,160	2	11	33	46
23	Other Power Gen O&M Exp		31,621	31,621	9,371	6,122	15,493	6	30	146	182
24	Other Power Supply O&M Exp		2,578	2,578	764	499	1,263	1	2	12	15
25	Total Production O&M Expense		66,869	66,869	19,984	13,159	33,143	17	82	327	426
26	Total Production (Inc. Fuel and P&I) O&M Expense		802,542	802,542	256,710	177,440	434,150	499	2,524	5,420	8,442
27	**Transmission & Distribution Expense**										
28	Trans O&M Exp		297,311	297,311	91,856	60,142	151,998	111	429	1,476	2,017
29	Other O&M Adjustments		0	0	0	0	0	0	0	0	0
30	Distr Oper Exp		88,134	88,134	19,869	12,010	31,879	98	3,197	219	3,514
31	Distr Maint Exp		241,863	241,863	57,731	34,056	91,787	160	718	598	1,475
32	Total Transmission & Distribution O&M Expense		627,308	627,308	169,456	106,208	275,663	369	4,344	2,293	7,006
33	**Customer Related Expense**										
34	Customer Accounts Exp		44,699	44,699	7,439	2,461	9,899	15	195	55	266
35	Customer Service Exp		4,319	4,319	830	393	1,222	2	14	12	28
36	Other Customer Exp		13,851	13,851	2,347	319	2,666	6	71	7	85
37	Total Customer O&M Expense		62,869	62,869	10,615	3,172	13,787	23	281	75	379
38	**Admin & General Expense**		58,950	58,950	14,200	8,368	22,568	35	497	166	699
39	**Total O&M Expense**		**1,551,669**	**1,551,669**	**450,981**	**295,188**	**746,169**	**927**	**7,645**	**7,953**	**16,526**

Line No.	(a) Description	(b)	(c) 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		45,351	18,326	27,900	211,554	52,901	74,769	147,365	16,626	2,563	337	597,691
3	Transmission		-	-	-	-	-	-	-	-	-	-	-
4	Distribution		115,745	15,075	35,128	406,656	91,803	153,471	364,734	13,602	3,794	961	1,200,971
5	General/Common/Intangible		7,778	2,142	3,327	34,223	6,801	9,895	26,559	1,882	318	65	92,989
6	Plant Purchased/Sold		0	0	0	0	0	0	0	0	0	0	0
7	Total Net Plant		168,874	35,543	66,356	652,433	151,505	238,135	538,658	32,110	6,674	1,362	1,891,651
8	**Working Capital**												
9	Total Current Assets		37,401	11,635	17,461	163,444	35,807	52,196	125,371	9,677	1,711	317	455,020
10	Total Current Liabilities		12,019	2,727	4,751	47,596	10,504	16,143	38,597	2,389	472	98	135,295
11	Total Working Capital		25,382	8,908	12,711	115,848	25,303	36,052	86,775	7,288	1,239	219	319,725
	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	3,287	855	759	20,366	3,924	688	3,017	95	2	33,310
15	Total Adjustments to Rate Base		(317)	(3,287)	(855)	(759)	(20,366)	(3,924)	(688)	(3,017)	(95)	(2)	(33,310)
16	**Total Rate Base**		**193,939**	**41,165**	**78,212**	**767,522**	**156,442**	**270,263**	**624,745**	**36,381**	**7,818**	**1,580**	**2,178,066**
17	**Production Expense**												
18	Fuel Expense		11,870	5,941	8,682	58,950	19,958	25,207	42,432	5,760	927	125	179,851
19	Purchased & Interchange Power Expense		23,945	11,277	16,660	116,705	36,479	47,362	83,210	10,748	1,712	229	348,326
20	Total Fuel and P&I Expense		35,814	17,219	25,342	175,655	56,437	72,569	125,642	16,507	2,639	354	528,177
21	Fossil O&M Exp		1,123	477	718	5,308	1,395	1,935	3,729	439	68	9	15,200
22	Nuclear O&M Exp		-	-	-	-	-	-	-	-	-	-	-
23	Hydro O&M Exp		270	117	175	1,282	343	473	904	108	17	2	3,691
23	Other Power Gen O&M Exp		1,296	524	798	6,048	1,512	2,137	4,213	475	73	10	17,087
24	Other Power Supply O&M Exp		106	43	65	493	123	174	343	39	6	1	1,393
25	Total Production O&M Expense		2,794	1,160	1,755	13,131	3,374	4,720	9,189	1,061	165	22	37,370
26	Total Production (Inc. Fuel and P&I) O&M Expense		38,609	18,378	27,097	188,786	59,811	77,289	134,831	17,568	2,803	375	565,547
27	**Transmission & Distribution Expense**												
28	Trans O&M Exp		13,412	5,476	8,439	62,683	17,343	23,281	41,382	5,209	820	128	178,174
29	Other O&M Adjustments		0	0	0	0	0	0	0	0	0	0	0
30	Distr Oper Exp		545	23	23	2,667	160	193	2,461	24	4	6	6,105
31	Distr Maint Exp		2,527	129	336	9,698	784	1,483	8,763	116	37	23	23,896
32	Total Transmission & Distribution O&M Expense		16,483	5,628	8,799	75,048	18,288	24,957	52,606	5,349	860	157	208,175
33	**Customer Related Expense**												
34	Customer Accounts Exp		386	186	220	1,698	433	625	1,223	112	23	4	4,909
35	Customer Service Exp		87	40	57	382	280	291	388	38	6	1	1,569
36	Other Customer Exp		23	1	2	30	2	4	23	1	0	0	85
37	Total Customer O&M Expense		495	227	279	2,110	715	919	1,633	151	29	5	6,563
38	**Admin & General Expense**		973	268	416	4,283	851	1,238	3,324	236	40	8	11,637
39	**Total O&M Expense**		**56,561**	**24,501**	**36,591**	**270,226**	**79,665**	**104,404**	**192,393**	**23,304**	**3,733**	**544**	**791,922**

Projected 12-Month Period Ending April 30, 2027
Version 2
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(g) Total Lighting & Unmetered	(f) Total Primary	(h) Rate GSG
	Input Allocation Schedules						
1	Energy @ Generation	100.000	42.781	23.790	0.550	32.323	0.557
2	Energy On-Peak @ Generation	100.000	40.400	25.227	0.415	33.526	0.432
3	Energy Off-Peak @ Generation	100.000	44.804	21.917	0.691	31.904	0.684
4	Energy On-Peak @ Generation Summer	100.000	41.357	25.482	0.340	32.381	0.440
5	Energy Off-Peak @ Generation Summer	100.000	45.009	22.115	0.614	31.526	0.736
6	Energy On-Peak @ Generation Non-Summer	100.000	39.837	25.077	0.459	34.199	0.428
7	Energy Off-Peak @ Generation Non-Summer	100.000	44.690	21.807	0.733	32.114	0.655
8	Energy Critical On-Peak @ Gen	100.000	43.786	25.634	0.257	30.012	0.310
9	Energy Summer Mid-Peak @ Gen	100.000	40.455	25.426	0.370	33.261	0.488
10	12CP Dmd @ Generation	100.000	47.053	24.056	0.319	28.198	0.374
11	4CP Dmd @ Generation	100.000	50.974	24.032	0.193	24.476	0.327
12	Class Peak @ Voltage 1	100.000	47.646	22.193	0.352	29.172	0.637
13	Production Revenue	100.000	45.243	24.069	0.404	30.272	0.012
14	Distribution Revenue	100.000	61.945	26.046	1.591	10.257	0.160
15	Total Rate Revenue	100.000	51.741	24.838	0.866	22.485	0.070
16	Billed Sales	100.000	37.529	21.431	0.483	40.044	0.513
17	Number Of Customers	100.000	87.628	11.864	0.290	0.217	0.001
18	Weighted Customer	100.000	60.171	28.622	0.054	11.116	0.038
	*Calculated Allocation Schedules						
19	4CP 75/0/25	100.000	48.925	23.971	0.282	26.437	0.384
20	4CP 75/0/25 Including ROA	100.000	47.609	23.179	0.404	28.402	0.406
21	4CP 75/0/25 Including ROA	100.000	47.609	23.179	0.404	28.402	0.406
22	4CP 75/0/25 Including ROA	100.000	47.609	23.179	0.404	28.402	0.406
23	Class Peak @ Voltage 2	100.000	50.507	23.525	0.373	24.919	0.676
24	Class Peak Voltage 1 Only	100.000	-	-	-	95.217	4.783
25	Class Peak Voltage 2 Only	100.000	-	-	-	95.360	4.640
26	Class Peak @ Voltage 1 excluding Voltage 2	100.000	50.758	23.642	0.375	24.849	0.376
27	Class Peak @ Voltage 3	100.000	54.198	25.244	0.400	20.079	0.078
28	Class Peak @ Voltage 4	100.000	67.881	31.618	0.501	-	-
29	Class Peak for Streetlighting	100.000	-	-	100.000	-	-
30	Class Peak @ Single Phase	100.000	67.881	31.618	0.501	-	-
31	Billed Sales - Primary	100.000	46.220	26.393	0.595	26.725	0.068
32	Customers - Residential	100.000	100.000	-	-	-	-
33	Customers - Drops	100.000	-	100.000	-	-	-
34	Customers - Non-Primary	100.000	88.057	11.922	0.021	-	-
35	Customers - NonMunicipal	100.000	87.883	11.899	-	0.218	0.001
36	Customers - Commercial & Primary	100.000	-	98.198	-	1.796	0.006
37	Customer Count (CCC)	100.000	93.559	6.441	-	-	-
38	Customer Count (BCC)	100.000	-	91.992	4.573	3.424	0.012
39	PIS - HVD (Voltage 1)	100.000	50.752	23.639	0.374	24.620	0.614
40	PIS - HVD (Voltage 2)	100.000	50.414	23.482	0.372	25.192	0.540
41	PIS - HVD (Voltage 1) Substations	100.000	50.507	23.525	0.373	24.919	0.676
42	PIS - HVD (Voltage 2) Substations	100.000	41.775	19.458	0.308	37.335	1.124
43	PIS - OH LVD System	100.000	64.018	29.818	0.472	5.669	0.022
44	PIS - LVD Distribution	100.000	63.318	25.881	2.402	8.278	0.122
45	PIS- OH (LVD & HVD) Lines & Services	100.000	66.522	25.401	0.389	7.595	0.093
46	PIS- UG LVD Distribution	100.000	63.659	29.651	0.470	6.132	0.088
47	PIS- Total Distribution	100.000	61.559	25.558	2.123	10.576	0.183

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

Projected 12-Month Period Ending April 30, 2027
Version 2
4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(b)	(c) Rate RS	(d) Total Residential	(e) Rate GS	(f) Rate GSD	(g) Commercial Secondary	(m) Rate GML	(n) Rate UUL	(o) Rate GU	(p) Lighting & Unmetered
	Input Allocation Schedules										
1	Energy @ Generation	100	42.781	42.781	13.916	9.874	23.790	0.036	0.184	0.330	0.550
2	Energy On-Peak @ Generation	101	40.400	40.400	15.034	10.193	25.227	0.018	0.096	0.300	0.415
3	Energy Off-Peak @ Generation	102	44.804	44.804	12.520	9.398	21.917	0.056	0.277	0.357	0.691
4	Energy On-Peak @ Generation Summer	103	41.357	41.357	15.224	10.258	25.482	0.009	0.058	0.273	0.340
5	Energy Off-Peak @ Generation Summer	104	45.009	45.009	12.643	9.472	22.115	0.046	0.237	0.331	0.614
6	Energy On-Peak @ Generation Non-Summer	105	39.837	39.837	14.922	10.155	25.077	0.023	0.119	0.317	0.459
7	Energy Off-Peak @ Generation Non-Summer	106	44.690	44.690	12.451	9.356	21.807	0.061	0.300	0.372	0.733
8	Energy Critical On-Peak @ Gen	107	43.786	43.786	15.378	10.256	25.634	0.001	0.004	0.252	0.257
9	Energy Summer Mid-Peak @ Gen	108	40.455	40.455	15.167	10.258	25.426	0.011	0.079	0.280	0.370
10	12CP Dmd @ Generation	120	47.053	47.053	14.537	9.518	24.056	0.018	0.068	0.234	0.319
11	4CP Dmd @ Generation	121	50.974	50.974	14.694	9.337	24.032	0.001	-	0.192	0.193
12	Class Peak @ Voltage 1	127	47.646	47.646	13.667	8.525	22.193	0.040	0.160	0.152	0.352
13	Production Revenue	141	45.243	45.243	14.305	9.764	24.069	0.022	0.108	0.273	0.404
14	Distribution Revenue	142	61.945	61.945	16.964	9.082	26.046	0.054	1.386	0.152	1.591
15	Total Rate Revenue	143	51.741	51.741	15.339	9.498	24.838	0.034	0.605	0.226	0.866
16	Billed Sales	150	37.529	37.529	12.262	9.168	21.431	0.032	0.162	0.289	0.483
17	Number Of Customers	160	87.628	87.628	10.789	1.075	11.864	0.021	0.245	0.024	0.290
18	Weighted Customer	170	60.171	60.171	23.312	5.310	28.622	0.054	-	-	0.054
	*Calculated Allocation Schedules										
19	4CP 75/0/25	220	48.925	48.925	14.500	9.472	23.971	0.010	0.046	0.226	0.282
20	4CP 75/0/25 Including ROA	222	47.609	47.609	14.037	9.142	23.179	0.040	0.169	0.195	0.404
21	4CP 75/0/25 Including ROA	224	47.609	47.609	14.037	9.142	23.179	0.040	0.169	0.195	0.404
22	4CP 75/0/25 Including ROA	226	47.609	47.609	14.037	9.142	23.179	0.040	0.169	0.195	0.404
23	Class Peak @ Voltage 2	122	50.507	50.507	14.488	9.037	23.525	0.042	0.169	0.161	0.373
24	Class Peak Voltage 1 Only	123	-	-	-	-	-	-	-	-	-
25	Class Peak Voltage 2 Only	124	-	-	-	-	-	-	-	-	-
26	Class Peak @ Voltage 1 excluding Voltage 2	125	50.758	50.758	14.560	9.082	23.642	0.042	0.170	0.162	0.375
27	Class Peak @ Voltage 3	230	54.198	54.198	15.547	9.697	25.244	0.045	0.182	0.173	0.400
28	Class Peak @ Voltage 4	231	67.881	67.881	19.472	12.146	31.618	0.057	0.228	0.216	0.501
29	Class Peak for Streetlighting	233	-	-	-	-	-	19.935	80.065	-	100.000
30	Class Peak @ Single Phase	235	67.881	67.881	19.472	12.146	31.618	0.057	0.228	0.216	0.501
31	Billed Sales - Primary	253	46.220	46.220	15.102	11.291	26.393	0.039	0.199	0.356	0.595
32	Customers - Residential	260	100.000	100.000	-	-	-	-	-	-	-
33	Customers - Drops	261	-	-	90.937	9.063	100.000	-	-	-	-
34	Customers - Non-Primary	263	88.057	88.057	10.842	1.080	11.922	0.021	-	-	0.021
35	Customers - NonMunicipal	264	87.883	87.883	10.821	1.078	11.899	-	-	-	-
36	Customers - Commercial & Primary	267	-	-	89.298	8.899	98.198	-	-	-	-
37	Customer Count (CCC)	161	93.559	93.559	6.388	0.054	6.441	-	-	-	-
38	Customer Count (BCC)	162	-	-	75.822	16.170	91.992	0.328	3.862	0.382	4.573
39	PIS - HVD (Voltage 1)	301	50.752	50.752	14.558	9.081	23.639	0.042	0.170	0.162	0.374
40	PIS - HVD (Voltage 2)	302	50.414	50.414	14.461	9.020	23.482	0.042	0.169	0.161	0.372
41	PIS - HVD (Voltage 1) Substations	303	50.507	50.507	14.488	9.037	23.525	0.042	0.169	0.161	0.373
42	PIS - HVD (Voltage 2) Substations	304	41.775	41.775	11.983	7.475	19.458	0.035	0.140	0.133	0.308
43	PIS - OH LVD System	305	64.018	64.018	18.364	11.455	29.818	0.053	0.215	0.204	0.472
44	PIS - LVD Distribution	306	63.318	63.318	16.490	9.391	25.881	0.073	2.169	0.160	2.402
45	PIS- OH (LVD & HVD) Lines & Services	307	66.522	66.522	15.897	9.504	25.401	0.044	0.177	0.168	0.389
46	PIS- UG LVD Distribution	308	63.659	63.659	18.261	11.390	29.651	0.053	0.214	0.203	0.470
47	PIS- Total Distribution	309	61.559	61.559	16.215	9.343	25.558	0.069	1.894	0.160	2.123

*Calculated allocation schedules may vary between productio

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(thousands of dollars)

Line No.	(a) Description	(b)	(c) 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	100	2.147	1.095	1.591	10.722	3.354	4.377	7.783	1.060	0.172	0.022	32.323
2	Energy On-Peak @ Generation	101	2.436	1.059	1.628	11.632	3.469	4.473	7.587	1.050	0.161	0.031	33.526
3	Energy Off-Peak @ Generation	102	1.805	1.120	1.529	9.594	3.882	4.778	7.947	1.056	0.181	0.011	31.904
4	Energy On-Peak @ Generation Summer	103	2.405	1.002	1.538	11.336	3.246	4.202	7.537	0.945	0.143	0.028	32.381
5	Energy Off-Peak @ Generation Summer	104	1.804	1.078	1.496	9.598	3.745	4.570	8.063	0.993	0.168	0.011	31.526
6	Energy On-Peak @ Generation Non-Summer	105	2.455	1.092	1.681	11.805	3.600	4.633	7.617	1.112	0.171	0.033	34.199
7	Energy Off-Peak @ Generation Non-Summer	106	1.805	1.144	1.548	9.592	3.958	4.894	7.882	1.092	0.189	0.012	32.114
8	Energy Critical On-Peak @ Gen	107	2.231	0.902	1.399	10.608	2.865	3.867	7.132	0.877	0.117	0.016	30.012
9	Energy Summer Mid-Peak @ Gen	108	2.470	1.039	1.590	11.606	3.387	4.326	7.687	0.970	0.152	0.033	33.261
10	12CP Dmd @ Generation	120	2.123	0.867	1.336	9.920	2.745	3.685	6.549	0.824	0.130	0.020	28.198
11	4CP Dmd @ Generation	121	1.959	0.716	1.115	8.903	2.002	2.951	6.097	0.627	0.094	0.013	24.476
12	Class Peak @ Voltage 1	127	2.145	0.697	1.008	8.183	4.318	4.630	7.420	0.640	0.112	0.019	29.172
13	Production Revenue	141	2.104	1.363	1.488	10.127	3.112	4.084	7.026	0.820	0.131	0.017	30.272
14	Distribution Revenue	142	1.056	0.075	0.270	4.096	0.268	1.014	3.354	0.043	0.064	0.016	10.257
15	Total Rate Revenue	143	1.696	0.862	1.014	7.781	2.006	2.890	5.598	0.518	0.105	0.017	22.485
16	Billed Sales	150	2.160	1.017	1.459	9.731	7.172	7.448	9.896	0.984	0.157	0.020	40.044
17	Number Of Customers	160	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	170	3.005	0.065	0.361	4.140	0.125	0.303	3.065	0.019	0.021	0.011	11.116
	*Calculated Allocation Schedules												
19	4CP 75/0/25	220	2.006	0.811	1.234	9.358	2.340	3.307	6.518	0.735	0.113	0.015	26.437
20	4CP 75/0/25 Including ROA	222	2.168	0.801	0.355	8.930	5.172	1.811	8.360	0.747	0.038	0.020	28.402
21	4CP 75/0/25 Including ROA	224	2.168	0.801	0.355	8.930	5.172	1.811	8.360	0.747	0.038	0.020	28.402
22	4CP 75/0/25 Including ROA	226	2.168	0.801	0.355	8.930	5.172	1.811	8.360	0.747	0.038	0.020	28.402
23	Class Peak @ Voltage 2	122	2.263	-	1.069	8.675	-	4.908	7.865	-	0.119	0.020	24.919
24	Class Peak Voltage 1 Only	123	0.169	11.714	-	-	72.583	-	-	10.752	-	-	95.217
25	Class Peak Voltage 2 Only	124	1.565	-	16.447	-	-	75.520	-	-	1.828	-	95.360
26	Class Peak @ Voltage 1 excluding Voltage 2	125	2.183	0.742	-	8.718	4.600	-	7.905	0.681	-	0.020	24.849
27	Class Peak @ Voltage 3	230	2.309	-	-	9.309	-	-	8.440	-	-	0.022	20.079
28	Class Peak @ Voltage 4	231	-	-	-	-	-	-	-	-	-	-	-
29	Class Peak for Streetlighting	233	-	-	-	-	-	-	-	-	-	-	-
30	Class Peak @ Single Phase	235	-	-	-	-	-	-	-	-	-	-	-
31	Billed Sales - Primary	253	2.529	-	-	11.984	-	-	12.188	-	-	0.025	26.725
32	Customers - Residential	260	-	-	-	-	-	-	-	-	-	-	-
33	Customers - Drops	261	-	-	-	-	-	-	-	-	-	-	-
34	Customers - Non-Primary	263	-	-	-	-	-	-	-	-	-	-	-
35	Customers - NonMunicipal	264	0.074	0.001	0.004	0.074	0.002	0.005	0.056	0.000	0.000	0.000	0.218
36	Customers - Commercial & Primary	267	0.613	0.009	0.035	0.610	0.016	0.042	0.465	0.002	0.003	0.002	1.796
37	Customer Count (CCC)	161	-	-	-	-	-	-	-	-	-	-	-
38	Customer Count (BCC)	162	1.168	0.018	0.066	1.162	0.030	0.080	0.886	0.004	0.006	0.004	3.424
39	PIS - HVD (Voltage 1)	301	2.262	0.036	0.952	8.717	0.221	4.371	7.904	0.033	0.106	0.020	24.620
40	PIS - HVD (Voltage 2)	302	1.934	-	1.685	7.149	-	7.738	6.482	-	0.187	0.017	25.192
41	PIS - HVD (Voltage 1) Substations	303	2.263	-	1.069	8.675	-	4.908	7.865	-	0.119	0.020	24.919
42	PIS - HVD (Voltage 2) Substations	304	2.138	-	3.770	7.175	-	17.311	6.506	-	0.419	0.017	37.335
43	PIS - OH LVD System	305	0.652	-	-	2.628	-	-	2.383	-	-	0.006	5.669
44	PIS - LVD Distribution	306	0.886	0.146	0.116	2.988	0.886	0.442	2.663	0.131	0.012	0.007	8.278
45	PIS- OH (LVD & HVD) Lines & Services	307	0.770	0.033	0.129	3.052	0.202	0.592	2.767	0.030	0.014	0.007	7.595
46	PIS- UG LVD Distribution	308	0.554	0.159	0.008	2.221	0.987	0.037	2.014	0.146	0.001	0.005	6.132
47	PIS- Total Distribution	309	1.046	0.128	0.297	3.635	0.775	1.285	3.255	0.115	0.032	0.009	10.576

*Calculated allocation schedules may vary between productic

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4CP 75/0/25 Production and 12CP Transmission
(thousands of dollars)

Line No.	(a) Description	(c) Total Electric	(d) Total Residential	(e) Total Commercial Secondary	(g) Total Lighting & Unmetered	(f) Total Primary	(h) 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	66.558	31.001	0.491	1.942	0.008
5	PIS- Meters	100.000	60.171	28.622	0.054	11.116	0.038
6	PIS - General	100.000	82.521	11.255	0.348	5.803	0.073
7	Total PIS	100.000	59.095	25.122	1.648	13.913	0.222
8	Distribution Depreciation	100.000	65.069	24.363	2.703	7.753	0.113
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	100.000	36.016	16.775	0.266	45.287	1.656
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	100.000	50.804	23.663	0.375	24.664	0.494
11	PIS- LVD OH Lines & Services	100.000	69.145	25.742	0.392	4.704	0.018
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	100.000	-	-	-	95.217	4.783
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	100.000	52.478	24.443	0.387	22.364	0.329
14	CWIP	100.000	57.558	25.981	0.465	15.760	0.238
15	Rate Base- Total	100.000	58.776	25.431	1.402	14.173	0.218
16	Dist Op Expense (LVD) excl Sup & Eng	100.000	68.400	24.626	2.763	4.186	0.025
17	Dist Maint Expense (LVD) excl Sup & Eng	100.000	68.976	25.808	0.415	4.782	0.018
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.429	21.160	0.335	32.117	0.959
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	100.000	45.871	21.366	0.338	31.498	0.926
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.923	23.253	0.368	25.925	0.529
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	100.000	49.650	23.126	0.366	26.317	0.541
22	Total HVD Distribution O&M Expense	100.000	48.525	22.602	0.358	27.859	0.656
23	Total Distribution O&M Expense (excl. HVD)	100.000	68.866	25.479	1.059	4.576	0.019
24	Total Customer Accounts Expense (excl. Supv)	100.000	74.762	16.557	0.445	8.210	0.026
25	Total Customer Accounts & Service Expense	100.000	73.219	16.613	0.440	9.676	0.053
26	Jurisdictional Distribution O&M	100.000	67.490	25.292	1.020	6.136	0.062
27	Pre Tax NOI	100.000	49.337	27.076	1.384	21.476	0.727
28	Depreciation & Amortization Expense	100.000	56.967	24.717	1.689	16.387	0.239
29	Non PSCR O&M Expense	100.000	64.437	23.997	0.807	10.631	0.129
30	Distribution Depreciation Expense	100.000	61.756	25.401	2.916	9.775	0.152
31	Gen/Comm/Int Depreciation Expense	100.000	62.713	24.008	0.743	12.380	0.156
32	Production Labor	100.000	48.925	23.971	0.282	26.437	0.384
33	Total Labor	100.000	62.713	24.008	0.743	12.380	0.156
34	50% O&M, 50% Net Plant	100.000	56.768	25.294	1.336	16.337	0.265
35	50/50 PIS & Labor	100.000	60.904	24.565	1.196	13.146	0.189

*Calculated allocation schedules may vary between production and distribution functions. Combined production and distribution shown.

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Line No.	(a) Description	(b)	(c) Rate RS	(d) Total Residential	(e) Rate GS	(f) Rate GSD	(g) Commercial Secondary	(m) Rate GML	(n) Rate UUL	(o) Rate GU	(p) Lighting & Unmetered
1	*Calculated Allocation Schedules										
2	PIS- Distribution Services	310	94.121	94.121	5.347	0.533	5.879	-	-	-	-
3	PIS- Streetlighting Equipment	311	-	-	-	-	-	1.423	98.577	-	100.000
4	PIS- Line Equipment	312	66.558	66.558	19.092	11.909	31.001	0.056	0.223	0.212	0.491
5	PIS- Meters	313	60.171	60.171	23.312	5.310	28.622	0.054	-	-	0.054
6	PIS - General	315	82.521	82.521	7.082	4.173	11.255	0.018	0.248	0.083	0.348
7	Total PIS	316	59.095	59.095	15.786	9.336	25.122	0.054	1.419	0.175	1.648
8	Distribution Depreciation	317	65.069	65.069	15.618	8.744	24.363	0.074	2.480	0.149	2.703
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	318	36.016	36.016	10.331	6.444	16.775	0.030	0.121	0.115	0.266
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	319	50.804	50.804	14.573	9.090	23.663	0.042	0.170	0.162	0.375
11	PIS- LVD OH Lines & Services	320	69.145	69.145	16.147	9.595	25.742	0.044	0.178	0.169	0.392
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	321	-	-	-	-	-	-	-	-	-
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	322	52.478	52.478	15.053	9.390	24.443	0.044	0.176	0.167	0.387
14	CWIP	330	57.558	57.558	15.993	9.988	25.981	0.035	0.230	0.200	0.465
15	Rate Base- Total	390	58.776	58.776	15.942	9.489	25.431	0.052	1.171	0.179	1.402
16	Dist Op Expense (LVD) excl Sup & Eng	400	68.400	68.400	15.352	9.274	24.626	0.076	2.518	0.169	2.763
17	Dist Maint Expense (LVD) excl Sup & Eng	401	68.976	68.976	16.258	9.549	25.808	0.045	0.203	0.167	0.415
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	402	45.429	45.429	13.031	8.128	21.160	0.038	0.152	0.145	0.335
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	403	45.871	45.871	13.158	8.208	21.366	0.038	0.154	0.146	0.338
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	404	49.923	49.923	14.321	8.933	23.253	0.042	0.167	0.159	0.368
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	405	49.650	49.650	14.242	8.884	23.126	0.041	0.167	0.158	0.366
22	Total HVD Distribution O&M Expense	406	48.525	48.525	13.919	8.682	22.602	0.041	0.163	0.155	0.358
23	Total Distribution O&M Expense (excl. HVD)	407	68.866	68.866	16.006	9.474	25.479	0.053	0.838	0.168	1.059
24	Total Customer Accounts Expense (excl. Supv)	408	74.762	74.762	12.442	4.116	16.557	0.026	0.327	0.092	0.445
25	Total Customer Accounts & Service Expense	409	73.219	73.219	12.351	4.262	16.613	0.026	0.313	0.100	0.440
26	Jurisdictional Distribution O&M	414	67.490	67.490	15.871	9.421	25.292	0.053	0.801	0.167	1.020
27	Pre Tax NOI	439	49.337	49.337	17.497	9.579	27.076	0.035	1.167	0.182	1.384
28	Depreciation & Amortization Expense	442	56.967	56.967	15.584	9.133	24.717	0.049	1.460	0.180	1.689
29	Non PSCR O&M Expense	443	64.437	64.437	15.206	8.791	23.997	0.041	0.593	0.172	0.807
30	Distribution Depreciation Expense	444	61.756	61.756	16.473	8.928	25.401	0.080	2.689	0.147	2.916
31	Gen/Comm/Int Depreciation Expense	445	62.713	62.713	15.107	8.902	24.008	0.038	0.529	0.177	0.743
32	Production Labor	500	48.925	48.925	14.500	9.472	23.971	0.010	0.046	0.226	0.282
33	Total Labor	502	62.713	62.713	15.107	8.902	24.008	0.038	0.529	0.177	0.743
34	50% O&M, 50% Net Plant	600	56.768	56.768	15.760	9.534	25.294	0.050	1.094	0.191	1.336
35	50/50 PIS & Labor	601	60.904	60.904	15.446	9.119	24.565	0.046	0.974	0.176	1.196

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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Cost-of-Service Study

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Line No.	(a) Description	(b)	(c) 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	310	-	-	-	-	-	-	-	-	-	-	-
3	PIS- Streetlighting Equipment	311	-	-	-	-	-	-	-	-	-	-	-
4	PIS- Line Equipment	312	0.223	-	-	0.900	-	-	0.816	-	-	0.002	1.942
5	PIS- Meters	313	3.005	0.065	0.361	4.140	0.125	0.303	3.065	0.019	0.021	0.011	11.116
6	PIS - General	315	0.485	0.134	0.208	2.136	0.424	0.618	1.658	0.117	0.020	0.004	5.803
7	Total PIS	316	1.239	0.277	0.497	4.859	1.101	1.696	3.935	0.250	0.049	0.010	13.913
8	Distribution Depreciation	317	0.839	0.075	0.181	2.837	0.447	0.751	2.531	0.066	0.019	0.007	7.753
9	PIS - HVD (Voltage 1) OH Lines (FERC 364/365)	318	1.592	3.930	-	6.186	24.349	-	5.609	3.607	-	0.014	45.287
10	PIS - HVD (Voltage 2) OH Lines (FERC 364/365)	319	2.264	-	1.007	8.726	-	4.623	7.912	-	0.112	0.020	24.664
11	PIS- LVD OH Lines & Services	320	0.541	-	-	2.181	-	-	1.977	-	-	0.005	4.704
12	PIS - HVD (Voltage 1) UG (FERC 366/367)	321	0.169	11.714	-	-	72.583	-	-	10.752	-	-	95.217
13	PIS - HVD (Voltage 2) UG (FERC 366/367)	322	2.287	-	0.503	9.013	-	2.311	8.172	-	0.056	0.021	22.364
14	CWIP	330	1.310	0.343	0.604	5.709	1.101	1.880	4.433	0.310	0.058	0.011	15.760
15	Rate Base- Total	390	1.262	0.268	0.509	4.994	1.018	1.759	4.065	0.237	0.051	0.010	14.173
16	Dist Op Expense (LVD) excl Sup & Eng	400	0.380	0.008	(0.005)	1.914	0.063	0.043	1.769	0.009	0.000	0.004	4.186
17	Dist Maint Expense (LVD) excl Sup & Eng	401	0.573	0.001	0.005	2.203	0.002	0.004	1.989	0.000	0.000	0.005	4.782
18	Dist Op Expense (HVD Voltage 1) excl Sup & Eng	402	2.006	1.550	0.462	7.803	9.605	2.124	7.075	1.423	0.051	0.018	32.117
19	Dist Maint Expense (HVD Voltage 1) excl Sup & Eng	403	2.025	1.438	0.484	7.879	8.912	2.223	7.144	1.320	0.054	0.018	31.498
20	Dist Op Expense (HVD Voltage 2) excl Sup & Eng	404	2.252	-	1.281	8.575	-	5.881	7.775	-	0.142	0.020	25.925
21	Dist Maint Expense (HVD Voltage 2) excl Sup & Eng	405	2.248	-	1.366	8.528	-	6.272	7.732	-	0.152	0.020	26.317
22	Total HVD Distribution O&M Expense	406	2.181	0.433	1.096	8.334	2.686	5.032	7.557	0.398	0.122	0.020	27.859
23	Total Distribution O&M Expense (excl. HVD)	407	0.516	0.002	0.000	2.113	0.014	0.006	1.919	0.002	0.000	0.005	4.576
24	Total Customer Accounts Expense (excl. Supv)	408	0.645	0.312	0.368	2.840	0.725	1.045	2.045	0.187	0.038	0.006	8.210
25	Total Customer Accounts & Service Expense	409	0.705	0.338	0.414	3.107	1.065	1.367	2.405	0.224	0.043	0.007	9.676
26	Jurisdictional Distribution O&M	414	0.628	0.031	0.074	2.529	0.193	0.343	2.295	0.029	0.008	0.006	6.136
27	Pre Tax NOI	439	1.700	1.874	1.018	7.615	1.090	2.705	5.380	(0.047)	0.120	0.021	21.476
28	Depreciation & Amortization Expense	442	1.442	0.396	0.652	5.804	1.318	1.937	4.411	0.355	0.062	0.011	16.387
29	Non PSCR O&M Expense	443	0.911	0.224	0.349	3.962	0.731	1.063	3.152	0.197	0.034	0.008	10.631
30	Distribution Depreciation Expense	444	1.109	0.110	0.263	3.434	0.647	1.049	3.032	0.096	0.027	0.008	9.775
31	Gen/Comm/Int Depreciation Expense	445	1.035	0.285	0.443	4.556	0.905	1.317	3.536	0.251	0.042	0.009	12.380
32	Production Labor	500	2.006	0.811	1.234	9.358	2.340	3.307	6.518	0.735	0.113	0.015	26.437
33	Total Labor	502	1.035	0.285	0.443	4.556	0.905	1.317	3.536	0.251	0.042	0.009	12.380
34	50% O&M, 50% Net Plant	600	1.372	0.366	0.627	5.617	1.407	2.085	4.450	0.337	0.063	0.012	16.337
35	50/50 PIS & Labor	601	1.137	0.281	0.470	4.707	1.003	1.507	3.735	0.250	0.046	0.009	13.146

*Calculated allocation schedules may vary between productic

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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		3,911,520	1,913,727	937,639	11,033	1,034,100	15,022
3	Transmission		0	-	-	-	-	-
4	Distribution		14,018,474	8,629,653	3,582,892	297,567	1,482,660	25,702
5	General/Common/Intangible		1,440,504	903,569	345,722	10,701	178,266	2,247
6	Plant Purchased/Sold		0	0	0	0	0	0
7	Total Plant in Service		19,370,498	11,446,949	4,866,252	319,301	2,695,026	42,970
8	**Depreciation Reserve**							
9	Production		1,829,448	895,065	438,541	5,160	483,656	7,026
10	Transmission		0	-	-	-	-	-
11	Distribution		3,990,342	2,596,488	972,147	107,847	309,363	4,496
12	General/Common/Intangible		830,853	521,139	199,419	6,172	102,827	1,296
13	Total Depreciation Reserve		6,650,643	4,012,692	1,610,107	119,180	895,847	12,818
14	**Construction Work In Progress (CWIP)**							
15	Production		178,717	87,438	42,841	504	47,248	686
16	Transmission		-	-	-	-	-	-
17	Distribution		267,258	162,407	75,646	1,198	27,525	482
18	General/Common/Intangible		132,835	83,304	31,892	987	16,444	207
19	Total CWIP		578,809	333,149	150,378	2,690	91,217	1,375
20	**Future Use**							
21	Production	220	0	0	0	0	0	0
22	Distribution	127	509	242	113	2	148	3
23	Common/General	502	8,930	5,600	2,144	66	1,106	14
24	PHFFU Depreciation Reserve	127	0	0	0	0	0	0
25	Total Future Use		9,439	5,843	2,257	68	1,254	17
26	Total Net Plant		13,308,103	7,773,249	3,408,780	202,879	1,891,651	31,545

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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		3,911,520	1,913,727	937,639	11,033	1,034,100	15,022
3	Generation Step Ups		0	0	0	0	0	0
4	Total Production		3,911,520	1,913,727	937,639	11,033	1,034,100	15,022
5	**Distribution Plant in Service**							
6	Stations and Equipment		3,779,644	2,063,005	960,902	15,223	723,416	17,098
7	Overhead System		6,743,986	4,165,284	1,940,097	30,735	600,541	7,328
8	Underground System		1,268,339	814,325	379,295	6,009	67,742	968
9	Meters and Svc Drops		1,994,151	1,587,038	302,598	13,247	90,961	307
10	St Lgts and OPL		232,354	-	-	232,354	-	-
11	Total Distribution		14,018,474	8,629,653	3,582,892	297,567	1,482,660	25,702
12	**General/Common/Intangible Plant in Service**							
13	Total Gen/Comm/Int Plant		1,440,504	903,569	345,722	10,701	178,266	2,247
14	**Plant Purchased/Sold**		0	0	0	0	0	0
15	**Total Plant in Service**		19,370,498	11,446,949	4,866,252	319,301	2,695,026	42,970

PLANT IN SERVICE (PRODUCTION & TRANSMISSION)

1	**Production Plant in Service**							
2	Fossil (Production-Steam)	220	1,024,947	501,460	245,692	2,891	270,968	3,936
3	Demand Response	220	52,343	25,609	12,547	148	13,838	201
4	Total Hydro	220	888,336	434,622	212,945	2,506	234,852	3,412
5	Other Production	220	1,945,894	952,036	466,455	5,489	514,442	7,473
6	Solar	220	0	0	0	0	0	0
7	Total Production Plant in Service		3,911,520	1,913,727	937,639	11,033	1,034,100	15,022

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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	18,243	8,692	4,049	64	5,322	116
4	HVD (Voltage 1) Other Land & ROW	127	5,915	2,818	1,313	21	1,726	38
5	HVD (Voltage 2) Substation Land & ROW	122	19,395	9,796	4,563	72	4,833	131
6	HVD (Voltage 2) Other Land & ROW	122	75,653	38,210	17,797	282	18,852	511
7	LVD Land & ROW	230	62,103	33,659	15,678	248	12,470	48
8	Total Distribution Land & ROW		181,309	93,176	43,399	688	43,202	845
9	Distribution Substations & Equipment (361/362)							-
10	HVD (Voltage 1) Bulk Power Substations (Shared V2,3,4)	122	535,042	270,236	125,870	1,994	133,327	3,615
11	HVD (Voltage 1) Distribution Substations (Shared V3,4)	230	431,195	233,700	108,852	1,724	86,582	336
13	HVD (Voltage 2) Bulk Power Substations (Shared V2,3,4)	122	33,446	16,892	7,868	125	8,334	226
14	HVD (Voltage 2) Distribution Substations (Shared V3,4)	230	982,300	532,390	247,976	3,928	197,241	765
15	HVD (Voltage 2) Substations (V2 Only)	124	128,234	-	-	-	122,283	5,951
16	Total Distribution Substations & Equipment		2,220,032	1,053,219	490,566	7,772	652,330	16,145
17	Distribution Storage Battery Equipment (363)							
18	LVD V3 Distribution Batteries (Shared: V3,4)	230	6,195	3,357	1,564	25	1,244	5
19	Total Distribution Battery Equipment		6,195	3,357	1,564	25	1,244	5
20	Distribution Overhead System (364/365)							
21	HVD (Voltage 1) OH Lines (Shared V1,3,4)	125	9,178	4,659	2,170	34	2,281	35
24	HVD (Voltage 2) OH Lines (Shared V2,3,4)	122	458,705	231,680	107,911	1,710	114,304	3,100
25	HVD (Voltage 2) OH Lines (Shared V3,4)	230	521,384	282,581	131,620	2,085	104,691	406
26	HVD (Voltage 2) OH Lines (V2 Only)	124	32,153	-	-	-	30,661	1,492
27	LVD Primary (Multi-Phase)	230	1,599,780	867,054	403,855	6,398	321,228	1,246
28	LVD Primary (Single Phase)	235	3,105,456	2,108,028	981,873	15,555	-	-
29	LVD Secondary	231	961,022	652,356	303,853	4,814	-	-
30	Total Distribution Overhead System		6,743,986	4,165,284	1,940,097	30,735	600,541	7,328
31	Distribution Underground System (366/367)							
32	HVD (Voltage 1) UG Lines (V1 Only)	123	15,027	-	-	-	14,308	719
36	LVD Primary (Multi-Phase)	230	246,597	133,651	62,252	986	49,515	192
37	LVD Primary (Single Phase)	235	825,564	560,405	261,024	4,135	-	-
38	LVD Secondary	231	163,631	111,075	51,736	820	-	-
39	Total Distribution Underground System		1,268,339	814,325	379,295	6,009	67,742	968
40	Distribution Line Equipment (368)							
41	LVD Primary	230	132,672	71,906	33,492	531	26,640	103
42	LVD Secondary	231	1,239,436	841,347	391,881	6,208	-	-
43	Total Distribution Line Equipment		1,372,108	913,253	425,373	6,739	26,640	103
44	Distribution Services (369)							
45	Residential	260	1,094,643	1,094,643	-	-	-	-
46	Commercial & Industrial	261	68,380	-	68,380	-	-	-
47	Total Distribution Services		1,163,023	1,094,643	68,380	-	-	-

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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	818,321	492,395	234,218	439	90,961	307
3	Total Distribution Metering Equipment		818,321	492,395	234,218	439	90,961	307
4	Distribution Installations on Customer Premises (371)							
5	Streetlighting Installations	DIR	12,807	-	-	12,807	-	-
6	Total Distribution Installations on Customer Premises		12,807	0	0	12,807	0	0
7	Distribution Streetlighting Equipment (373)							
8	Luminaires/Suspensions/Poles/Transformers	DIR	215,771	-	-	215,771	-	-
9	Underground Cable & Conduits	233	9,571	-	-	9,571	-	-
10	Photoelectric Switches	233	7,012	-	-	7,012	-	-
11	Total Distribution Streetlighting Equipment		232,354	-	-	232,354	-	-
12	Total Distribution Plant in Service		14,018,474	8,629,653	3,582,892	297,567	1,482,660	25,702
13	Total Distribution Plant in Service	309	14,018,474	8,629,653	3,582,892	297,567	1,482,660	25,702
14	**Electric Plant Purchased & Sold**	220	0	0	0	0	0	0
15	**General, Common & Intangible Plant in Service**							
16	C&I Online Acct Management	502	447	280	107	3	55	1
17	MIMO EE/3.0 (U-20963 Order)	260	506	506	-	-	-	-
18	General, Common & Intangible	502	1,439,552	902,783	345,614	10,697	178,210	2,246
19	Total General, Common & Intangible Plant in Service		1,440,504	903,569	345,722	10,701	178,266	2,247

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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		1,829,448	895,065	438,541	5,160	483,656	7,026
3	Generation Step Ups		0	0	0	0	0	0
4	Total Production Depreciation Reserve		1,829,448	895,065	438,541	5,160	483,656	7,026
5	**Distribution Depreciation Reserve**							
6	Stations and Equipment		819,017	467,229	217,625	3,448	127,790	2,926
7	Overhead System		1,842,871	1,156,877	538,847	8,536	137,319	1,292
8	Underground System		365,329	235,960	109,905	1,741	17,534	189
9	Meters and Svc Drops		873,081	736,423	105,770	4,078	26,720	90
10	St Lgts and OPL		90,044	-	-	90,044	-	-
11	Total Distribution Depreciation Reserve		3,990,342	2,596,488	972,147	107,847	309,363	4,496
12	**Total General, Common & Intangible Depreciation Reserve**		830,853	521,139	199,419	6,172	102,827	1,296
13	**Total Depreciation Reserve**		6,650,643	4,012,692	1,610,107	119,180	895,847	12,818

DEPRECIATION RESERVE (PRODUCTION & TRANSMISSION)

1	**Production Depreciation Reserve**							
2	Fossil (Production-Steam)	220	451,552	220,924	108,242	1,274	119,378	1,734
3	Demand Response	220	5,479	2,680	1,313	15	1,448	21
4	Hydro	220	660,483	323,144	158,326	1,863	174,614	2,536
5	Other Production	220	711,934	348,317	170,659	2,008	188,216	2,734
6	Solar	220	0	0	0	0	0	0
7	Total Production Depreciation Reserve		1,829,448	895,065	438,541	5,160	483,656	7,026

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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	301	143	67	1	88	2
4	HVD (Voltage 1) Other Land & ROW	127	1,225	584	272	4	357	8
5	HVD (Voltage 2) Substation Land & ROW	122	320	162	75	1	80	2
6	HVD (Voltage 2) Other Land & ROW	122	15,667	7,913	3,686	58	3,904	106
7	LVD Land & ROW	230	13,809	7,484	3,486	55	2,773	11
8	Total Distribution Land & ROW Depreciation Reserve		31,322	16,286	7,586	120	7,202	129
9	Distribution Substations & Equipment (361/362)							
10	HVD (Voltage 1) Bulk Power Substations (Shared V2,3,4)	122	104,288	52,673	24,534	389	25,988	705
11	HVD (Voltage 1) Distribution Substations (Shared V3,4)	230	75,619	40,984	19,089	302	15,184	59
14	HVD (Voltage 1) Substations (V1 Only)	123	17,982	-	-	-	17,122	860
15	HVD (Voltage 2) Bulk Power Substations (Shared V2,3,4)	122	5,820	2,939	1,369	22	1,450	39
16	HVD (Voltage 2) Substations (V2 Only)	124	21,030	-	-	-	20,054	976
17	Total Distribution, Substations & Equipment Depreciation Reserve		385,504	183,729	85,577	1,356	112,079	2,764
17	Distribution Storage Battery Equipment (363)							
18	Batteries: LVD (Voltage 3)	230	3,865	2,095	976	15	776	3
19	Total Distribution Battery Equipment		3,865	2,095	976	15	776	3
20	Distribution Overhead System (364/365)		-	-	-	-	-	-
21	HVD (Voltage 1) OH Lines (Shared V1,3,4)	125	1,430	726	338	5	355	5
22	HVD (Voltage 1) OH Lines (Shared V3,4)	230	5,750	3,116	1,451	23	1,155	4
23	HVD (Voltage 1) OH Lines (V1 Only)	123	3,416	-	-	-	3,253	163
24	HVD (Voltage 2) OH Lines (Shared V2,3,4)	122	68,457	34,576	16,105	255	17,059	463
25	HVD (Voltage 2) OH Lines (Shared V3,4)	230	77,292	41,891	19,512	309	15,520	60
26	HVD (Voltage 2) OH Lines (V2 Only)	124	4,868	-	-	-	4,643	226
27	LVD	305	1,681,658	1,076,568	501,441	7,944	95,335	370
28	Total Distribution Overhead System Depreciation Reserve		1,842,871	1,156,877	538,847	8,536	137,319	1,292
29	Distribution Underground System (366/367)							
30	HVD (Voltage 1) UG Lines (V1 Only)	123	2,577	-	-	-	2,454	123
31	HVD (Voltage 2) UG Lines (Shared V2,3,4)	122	1,091	551	257	4	272	7
32	HVD (Voltage 2) UG Lines (Shared V3,4)	230	1,859	1,008	469	7	373	1
33	HVD (Voltage 2) UG Lines (V2 Only)	124	20	-	-	-	19	1
34	LVD	308	359,782	234,402	109,179	1,730	14,416	56
35	Total Distribution Underground System Depreciation Reserve		365,329	235,960	109,905	1,741	17,534	189
36	Distribution Line Equipment (368)							
37	Capacitors/Regulators/Transformers	312	398,325	265,119	123,486	1,956	7,734	30
38	Total Distribution Line Equipment Depreciation Reserve		398,325	265,119	123,486	1,956	7,734	30
39	Distribution Services (369)							
40	C&I and Residential Services	310	628,746	591,779	36,967	-	-	-
41	Total Distribution Services Depreciation Reserve		628,746	591,779	36,967	-	-	-

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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	240,387	144,644	68,803	129	26,720	90
3	Total Distribution Metering Equpment Depreciation Reserve		240,387	144,644	68,803	129	26,720	90
4	Distribution Installations on Customer Premises (371)							
5	Streetlighting Installations	DIR	3,949	-	-	3,949	-	-
6	Total Distribution Installations on Customer Premises Depreciation Reserve		3,949	0	0	3,949	0	0
7	Distribution Streetlighting Equipment (373)							
8	Streetlighting Equipment	311	90,044	-	-	90,044	-	-
9	Total Distribution Streetlighting Depreciation Reserve		90,044	-	-	90,044	-	-
10	Total Distribution Depreciation Reserve		3,990,342	2,596,488	972,147	107,847	309,363	4,496
11	Total Distribution Depreciation Reserve	317	3,990,342	2,596,488	972,147	107,847	309,363	4,496
12	**General, Common & Intangible Depreciation Reserve**							
13	C&I Online Acct Management	502	45	28	11	0	6	0
14	MIMO EE/3.0 (U-20963 Order)	260	235	235	-	-	-	-
0	Intangible Amortization Reserve	502	0	0	0	0	0	0
15	General, Common & Intangible	502	830,574	520,876	199,408	6,172	102,822	1,296
16	Total General, Common & Intangible Depreciation Reserve		830,853	521,139	199,419	6,172	102,827	1,296

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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	178,717	87,438	42,841	504	47,248	686
3	Total Production CWIP		178,717	87,438	42,841	504	47,248	686
4	**Distribution CWIP**							
5	HVD (Voltage 1)	127	22,911	10,916	5,085	81	6,684	146
6	HVD (Voltage 2)	122	44,024	22,235	10,357	164	10,970	297
7	LVD Distribution	306	200,323	129,255	60,204	954	9,871	38
8	Total Distribution CWIP		267,258	162,407	75,646	1,198	27,525	482
9	**General/Common/Intangible CWIP**							
10	Plant Held for Future Use	502	0	0	0	0	0	0
11	General, Common & Intangible	502	132,835	83,304	31,892	987	16,444	207
12	Total General, Common & Intangible CWIP		132,835	83,304	31,892	987	16,444	207

WORKING CAPITAL

1	**Current Assets**							
2	Cash & Cash Equivalents	316	50,385	30,058	12,690	869	6,662	107
3	Accts Receivable	143	280,141	146,114	69,719	2,509	61,593	206
4	Material and Supplies	316	216,848	129,362	54,614	3,738	28,672	462
5	Fuel Stock	100	64,489	27,589	15,342	355	20,845	359
6	Deferred Taxes	316	272,280	162,430	68,575	4,693	36,001	580
7	Other Cur Assets	502	1,263,051	792,095	303,239	9,386	156,360	1,971
8	Deferred Debits	502	842,494	528,352	202,270	6,261	104,297	1,315
9	1/ Karn & Campbell Regulatory Assets	220	143,378	70,148	34,369	404	37,905	551
10	PMF Regulatory Asset	143	3,990	2,081	993	36	877	3
11	PMD Regulatory Asset	143	8,216	4,285	2,045	74	1,806	6
12	Total Current Assets		3,145,271	1,892,513	763,856	28,324	455,020	5,559
13	**Current Liabilities**							
14	Accounts Payable	316	474,206	282,891	119,431	8,174	62,701	1,010
15	Customer Deposits	143	22,955	11,973	5,713	206	5,047	17
16	Dividends Payable	316	24,539	14,639	6,180	423	3,245	52
17	Accrued Interest	316	66,062	39,410	16,638	1,139	8,735	141
18	Accrued Taxes - Federal	502	2,331	1,462	560	17	289	4
19	Accrued Taxes - State	601	649	398	159	8	82	1
20	Accrued Taxes - R&PP & Other	316	253,100	150,989	63,745	4,363	33,466	539
21	Other Current Liabilities	502	72,728	45,609	17,461	540	9,003	113
22	Deferred CR	502	102,814	64,478	24,684	764	12,728	160
23	Total Current Liabilities		1,019,384	611,847	254,571	15,634	135,295	2,037
24	**Total Working Capital**		2,125,887	1,280,666	509,285	12,690	319,725	3,522

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	28,060	-	-	-	26,718	1,342
6	Customer Advances- Voltage 2 Customers	124	5,196	-	-	-	4,955	241
7	Customer Advances- LVD Customers	306	33,217	21,433	9,983	158	1,637	6
8	Total Deductions		66,473	21,433	9,983	158	33,310	1,589
9	**Total Adjustments to Rate Base**		(66,473)	(21,433)	(9,983)	(158)	(33,310)	(1,589)

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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							
3	Revenue From Electric Sales	DIR	2,429,573	1,475,923	635,100	28,433	286,819	3,298
4	Provision for Rate Refund	DIR	0	-	-	-	-	-
0	Unbilled Revenue	DIR	0	-	-	-	-	-
4	Total Non PSCR Rate Revenue		2,429,573	1,475,923	635,100	28,433	286,819	3,298
5	PSCR Base Revenue	DIR	2,004,517	845,483	470,163	10,879	677,992	-
6	Unbilled PSCR Base Revenue	DIR	0	-	-	-	-	-
7	Total PSCR Rate Revenue		2,004,517	845,483	470,163	10,879	677,992	-
8	Total Rate Revenue		4,434,089	2,321,406	1,105,262	39,312	964,811	3,298
10	**Non-PSCR Rate Revenue Credits**							
11	450 Late Payment Charge Revenue	DIR	9,623	5,915	2,545	-	1,149	13
12	451 Miscellaneous Service & Reconnect Fees	253	1,056	488	279	6	282	1
13	454 Pole Rental Rev	307	12,965	8,625	3,293	50	985	12
14	454 Other Rents	316	2,029	1,258	516	41	209	4
15	456 Purchased Power Administrative Fees	100	642	274	153	4	207	4
16	Other Revenues	150	10,486	3,935	2,247	51	4,199	54
17	Job Work Revenue	414	1,663	1,122	421	17	102	1
18	LEDR & LTILRR: Production	DIR	212,169	95,397	49,152	1,105	65,371	1,144
19	LEDR & LTILRR: Delivery	390	11,576	7,129	2,991	198	1,238	20
20	Non PSCR Revenue Credits		262,208	124,144	61,597	1,472	73,743	1,252
22	PSCR Factor Revenue	DIR	284,114	119,836	66,639	1,542	96,097	-
23	Unbilled PSCR Factor Revenue	DIR	0	-	-	-	-	-
24	Intersystem Sales	220	24,609	12,040	5,899	69	6,506	95
25	GSG and GI Market Price Revenue	DIR	15,603	-	-	-	-	15,603
26	PSCR Revenue Credits		324,326	131,876	72,538	1,611	102,603	15,698
27	Total Revenue Credits		586,534	256,020	134,135	3,083	176,346	16,950
28	Total Revenue		5,020,623	2,577,426	1,239,398	42,395	1,141,157	20,248

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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	87,893	35,557	22,347	325	29,234	429
3	On-Peak Winter Fuel for Gen	105	190,669	75,957	47,813	875	65,207	817
4	Off-Peak Summer Fuel for Gen	104	83,800	37,717	18,532	515	26,419	617
5	Off-Peak Winter Fuel for Gen	106	150,867	67,423	32,900	1,106	48,450	988
6	Critical Summer Peak Energy	107	35,120	15,378	9,003	90	10,540	109
7	Total Fuel Expense		548,348	232,032	130,596	2,911	179,851	2,959
	Purchased & Interchange Power Expense							
9	Mid-Peak Summer Purchased Power	108	122,921	49,728	31,254	455	40,885	600
10	On-Peak Winter Purchased Power	105	266,658	106,228	66,869	1,224	91,195	1,142
11	Off-Peak Summer Purchased Power	104	117,198	52,749	25,918	720	36,948	863
12	Off-Peak Winter Purchased Power	106	210,993	94,294	46,012	1,547	67,759	1,382
13	Critical Peak Summer Purchased Power	107	49,117	21,507	12,591	126	14,741	152
14	Purchased Power Capacity: Capacity Costs	121	0	0	0	0	0	0
15	Purchased Power Capacity: Other	220	366,140	179,136	87,768	1,033	96,798	1,406
16	Total Purchased & Interchange Power Expense		1,133,028	503,642	270,412	5,104	348,326	5,544
17	Total Fuel and Purchased & Interchange Power Expense		1,681,377	735,673	401,007	8,016	528,177	8,503

PRODUCTION O&M (2)

1	Fossil Plant O&M Expense							
2	Capacity Related Operations	220	39,714	19,430	9,520	112	10,499	153
3	Capacity Related Maintenance	220	5,484	2,683	1,314	15	1,450	21
4	Energy Related Operations	100	(10,263)	(4,390)	(2,441)	(56)	(3,317)	(57)
5	Energy Related Maintenance	100	12,765	5,461	3,037	70	4,126	71
6	Capacity Related Fuel Handling	220	0	0	0	0	0	0
7	Energy Related Fuel Handling	100	7,555	3,232	1,797	42	2,442	42
8	Total Fossil O&M Expense		55,255	26,416	13,227	183	15,200	230
9	Hydro Plant O&M Expense							
10	Capacity Related Operations	220	7,234	3,539	1,734	20	1,913	28
11	Capacity Related Maintenance	220	2,593	1,269	622	7	686	10
12	Energy Related Operations	100	(607)	(260)	(144)	(3)	(196)	(3)
13	Energy Related Maintenance	100	3,988	1,706	949	22	1,289	22
14	Total Hydro O&M Total		13,209	6,255	3,160	46	3,691	57
15	Other Power Generation O&M Expense							
16	Capacity Related Operations & Maintenance	220	64,631	31,621	15,493	182	17,087	248
17	Energy Related Operations & Maintenance	100	0	0	0	0	0	0
18	Total Other Power Gen O&M Expense		64,631	31,621	15,493	182	17,087	248
19	Other Power Supply Expense							
20	Capacity Related Operations & Maintenance	220	5,268	2,578	1,263	15	1,393	20
21	Energy Related Operations & Maintenance	100	0	0	0	0	0	0
22	Total Other Power Supply O&M Expense		5,268	2,578	1,263	15	1,393	20
23	Disposition of Allowances	220	0	0	0	0	0	0
24	**Total Production O&M (excluding Fuel and P&I)**		138,363	66,869	33,143	426	37,370	555
25	**Total Production O&M Expense**		1,819,739	802,542	434,150	8,442	565,547	9,058

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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	631,863	297,311	151,998	2,017	178,174	2,363
3	Total Transmission O&M Expense		631,863	297,311	151,998	2,017	178,174	2,363

DISTRIBUTION O&M

1	**Distribution Operation Expense**							
2	580 Supv & Engineering - Distribution (LVD)	400	31,980	21,874	7,875	884	1,339	8
3	580 Supv & Engineering - HVD (Voltage 1)	402	354	161	75	1	114	3
4	580 Supv & Engineering - HVD (Voltage 2)	404	665	332	155	2	173	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	411	193	90	1	124	4
8	582 Station Expense - HVD (Voltage 2)	304	437	210	98	2	125	3
9	583 Overhead Expense - Distribution (LVD)	320	55,422	38,321	14,266	217	2,607	10
10	583 Overhead Expense - HVD (Voltage 1)	318	61	22	10	0	28	1
11	583 Overhead Expense - HVD (Voltage 2)	319	948	481	224	4	234	5
12	584 Underground Lines- Distribution (LVD)	308	8,708	5,673	2,642	42	349	1
13	584 Underground Lines- HVD (Voltage 1)	321	34	-	-	-	32	2
14	584 Underground Lines- HVD (Voltage 2)	322	40	21	10	0	9	0
15	585 Street Lighting & Signal System	311	1,594	-	-	1,594	-	-
16	586 Metering Expense	313	(3,700)	(2,227)	(1,059)	(2)	(411)	(1)
17	587 Customer Installations	160	4,675	4,097	555	14	10	0
18	588 Miscellaneous	400	24,934	17,055	6,140	689	1,044	6
19	589 Rents	309	3,121	1,921	798	66	330	6
20	Total Distribution Operation Expense		129,682	88,134	31,879	3,514	6,105	51
21	Distribution Maintenance Expense							
22	590 Supv & Engineering - Distribution (LVD)	401	3,870	2,669	999	16	185	1
23	590 Supv & Engineering - HVD (Voltage 1)	403	274	126	58	1	86	3
24	590 Supv & Engineering - HVD (Voltage 2)	405	514	255	119	2	135	3
25	591 Structures - Distribution (LVD)	230	0	0	0	0	0	0
26	591 Structures - HVD (Voltage 1)	303	362	169	79	1	109	3
27	591 Structures - HVD (Voltage 2)	304	385	185	86	1	110	2
28	592 Station Equipment - Distribution (LVD)	230	0	0	0	0	0	0
29	592 Station Equipment - HVD (Voltage 1)	303	7,352	3,443	1,604	25	2,217	63
30	592 Station Equipment - HVD (Voltage 2)	304	7,816	3,753	1,748	28	2,240	47
31	593 Overhead Lines - Distribution (LVD)	320	319,492	220,912	82,242	1,252	15,028	58
32	593 Overhead Lines - HVD (Voltage 1)	318	752	271	126	2	340	12
33	593 Overhead Lines - HVD (Voltage 2)	319	11,621	5,904	2,750	44	2,866	57
34	594 Underground Lines- Distribution (LVD)	308	2,170	1,414	658	10	87	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	233	155	72	1	5	0
38	596 Street Lighting & Signal System	311	89	-	-	89	-	-
39	597 Meters	313	4,413	2,656	1,263	2	491	2
40	598 Miscellaneous	401	(70)	(48)	(18)	(0)	(3)	(0)
41	Total Distribution Maintenance Expense		359,273	241,863	91,787	1,475	23,896	252
42	**Total Distribution O&M Expense**		488,955	329,997	123,666	4,989	30,001	303

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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	3,606	2,696	597	16	296	1
3	902 Meter Reading	263	11,010	9,695	1,313	2	-	-
4	903 Rcrds & Collection	160	24,898	21,818	2,954	72	54	0
5	904 Uncollectibles	143	20,274	10,490	5,036	176	4,559	14
6	905 Misc Expenses	408	0	0	0	0	0	0
7	Total Customer Accounts		59,788	44,699	9,899	266	4,909	15
8	**Customer Services Expense**							
9	907 Supervision	160	(0)	(0)	(0)	(0)	(0)	(0)
10	908 Customer Assist	603	3,900	1,464	836	19	1,562	20
11	909 Info & Inst	160	3,258	2,855	387	9	7	0
12	910 Miscellaneous	160	0	0	0	0	0	0
13	Total Customer Services		7,158	4,319	1,222	28	1,569	20
14	**Other Expense**							
15	911-916 Sales Expense	160	72	63	9	0	0	0
16	Customer Contact Center (CCC)	161	14,613	13,672	941	-	-	-
17	Business Customer Care (BCC)	162	1,817	-	1,671	83	62	0
18	Multi Acct Mgmt Project (Formerly C&I Online Acct Mgmt)	502	185	116	44	1	23	0
19	Total Other Expense		16,687	13,851	2,666	85	85	1
20	**Administrative & General Expense**							
21	Production	500	26,519	12,975	6,357	75	7,011	102
22	HV Distribution	406	4,497	2,182	1,017	16	1,253	30
23	Distribution	407	53,360	36,747	13,596	565	2,442	10
24	Customer	409	9,623	7,046	1,599	42	931	5
25	Total Administrative & General Expense		94,000	58,950	22,568	699	11,637	147
26	**Total O&M Expense (excluding PSCR Expense)**		804,952	518,685	193,164	6,493	85,571	1,040
27	Test Year Other O&M Expense	443	0	-	0	0	0	0
27	**Total O&M Expense**		3,118,192	1,551,669	746,169	16,526	791,922	11,906

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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		305,550	149,491	73,244	862	80,779	1,173
3	Total Production		305,550	149,491	73,244	862	80,779	1,173
4	**Distribution**							
5	Stations and Equipment		91,148	50,543	23,542	373	16,306	384
6	Overhead System		199,868	123,733	57,632	913	17,383	206
7	Underground System		29,284	18,699	8,709	138	1,709	29
8	Meters and Svc Drops		88,004	65,478	16,421	573	5,513	19
9	St Lgts and OPL		10,207	-	-	10,207	-	-
11	Total Distribution		418,510	258,453	106,305	12,203	40,911	638
12	**General/Common/Intangible**							
13	General, Common & Intangible		83,508	52,370	20,049	621	10,338	130
14	Test Year Gen/Comm/Int Change	445	0	0	0	0	0	0
15	Total General/Common/Intangible Dep Expense		83,508	52,370	20,049	621	10,338	130
16	**Other Amortization Expense**		5,520	2,879	1,374	49	1,214	4
17	**Total Depreciation & Amortization Expense**		813,088	463,194	200,972	13,735	133,242	1,945

DEPRECIATION EXPENSE (PRODUCTION & TRANSMISSION)

1	**Production Depreciation Expense**							
2	Fossil (Production-Steam)	220	191,760	93,819	45,967	541	50,696	736
3	Demand Response	220	2,806	1,373	673	8	742	11
4	Hydro	220	63,954	31,290	15,330	180	16,908	246
5	Other Production	220	47,030	23,010	11,274	133	12,433	181
6	Solar	220	0	0	0	0	0	0
7	Total Production Depreciation Expense		305,550	149,491	73,244	862	80,779	1,173

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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	196	94	44	1	57	1
4	HVD (Voltage 1) Other Land & ROW	127	61	29	14	0	18	0
5	HVD (Voltage 2) Substation Land & ROW	122	209	105	49	1	52	1
6	HVD (Voltage 2) Other Land & ROW	122	785	397	185	3	196	5
7	LVD Land & ROW	230	790	428	199	3	159	1
8	Total Distribution Land & ROW Depreciation Expense		2,042	1,053	490	8	482	9
9	Distribution Substations & Equipment (361/362)							
10	HVD (Voltage 1) Bulk Power Substations (Shared V2,3,4)	122	12,208	6,166	2,872	45	3,042	82
11	HVD (Voltage 1) Distribution Substations (Shared V3,4)	230	9,909	5,370	2,501	40	1,990	8
12	HVD (Voltage 1) Substations (V1 Only)	123	2,533	-	-	-	2,412	121
13	HVD (Voltage 2) Bulk Power Substations (Shared V2,3,4)	122	769	389	181	3	192	5
14	HVD (Voltage 2) Distribution Substations (Shared V3,4)	124	22,648	12,275	5,717	91	4,548	18
15	HVD (Voltage 2) Substations (V2 Only)	124	2,959	-	-	-	2,822	137
16	Total Distribution Substations & Equipment Depreciation Expense		51,026	24,200	11,272	179	15,005	372
			-	-	-	-	-	-
17	Distribution Storage Battery Equipment (363)		-	-	-	-	-	-
18	Batteries: LVD (Voltage 3)	230	442	240	112	2	89	0
19	Total Distribution Battery Equipment		442	240	112	2	89	0
20	Distribution Overhead System (364/365)							
21	HVD (Voltage 1) OH Lines (Shared V1,3,4)	125	245	125	58	1	61	1
22	HVD (Voltage 1) OH Lines (Shared V3,4)	230	938	509	237	4	188	1
23	HVD (Voltage 1) OH Lines (V1 Only)	123	609	-	-	-	579	29
24	HVD (Voltage 2) OH Lines (Shared V2,3,4)	122	12,659	6,394	2,978	47	3,154	86
25	HVD (Voltage 2) OH Lines (Shared V3,4)	230	14,488	7,852	3,657	58	2,909	11
26	HVD (Voltage 2) OH Lines (V2 Only)	124	893	-	-	-	851	41
27	LVD	305	170,035	108,854	50,702	803	9,640	37
28	Total Distribution Overhead Depreciation Expense		199,868	123,733	57,632	913	17,383	206
29	Distribution Underground System (366/367)							
30	HVD (Voltage 1) UG Lines (V1 Only)	123	471	-	-	-	449	23
31	HVD (Voltage 2) UG Lines (Shared V2,3,4)	122	215	108	50	1	53	1
32	HVD (Voltage 2) UG Lines (Shared V3,4)	230	358	194	90	1	72	0
33	HVD (Voltage 2) UG Lines (V2 Only)	124	4	-	-	-	3	0
34	LVD	308	28,236	18,396	8,568	136	1,131	4
35	Total Distribution Underground Depreciation Expense		29,284	18,699	8,709	138	1,709	29
36	Distribution Line Equipment (368)							
37	Line Equipment	312	37,638	25,051	11,668	185	731	3
38	Total Distribution Line Equipment Depreciation Expense		37,638	25,051	11,668	185	731	3
39	Distribution Services (369)							
40	Overhead & Underground Services	310	37,862	35,636	2,226	-	-	-
41	Total Distribution Services Depreciation Expense		37,862	35,636	2,226	-	-	-

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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 (cont.)**							
2	Distribution Metering Equipment (370)		-	-	-	-	-	-
3	Metering Equipment	170	49,596	29,843	14,195	27	5,513	19
4	Total Distribution Metering Equipment Depreciation Expense		49,596	29,843	14,195	27	5,513	19
5	Distribution Installations on Customer Premises (371)		-	-	-	-	-	-
6	Streetlighting Installations	DIR	546	-	-	546	-	-
7	Total Distribution Installations on Customer Premises		546	0	0	546	0	0
8	Distribution Streetlighting Equipment Depreciation Expense (373)	311	10,207	-	-	10,207	-	-
9	**Total Distribution Depreciation Expense**		418,510	258,453	106,305	12,203	40,911	638
10	**General/Common/Intangible**							
11	C&I Online Account Management	502	89	56	21	1	11	0
12	MIMO EE/3.0 (U-20963 Order)	502	101	63	24	1	13	0
13	General, Common & Intangible	502	83,318	52,251	20,003	619	10,314	130
14	Total Gen/Comm/Int Depreciation Expense		83,508	52,370	20,049	621	10,338	130
15	**Other Amortization**							
16	PMF Amortization	143	1,782	929	443	16	392	1
17	PMD Amortization	143	3,738	1,950	930	33	822	3
18	Total Other Amortization Expense		5,520	2,879	1,374	49	1,214	4
19	**Total Depreciation & Amortization Expense**		813,088	463,194	200,972	13,735	133,242	1,945

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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	1,150	432	246	6	461	6
2	State Income Tax	439	33,324	16,441	9,023	461	7,156	242
	RP&P Tax							
4	R&PP Taxes - Prod	220	63,820	31,224	15,298	180	16,872	245
5	R&PP Taxes - HVD (Voltage 1)	301	18,780	8,574	3,993	63	5,972	178
6	R&PP Taxes - HVD (Voltage 2)	302	36,087	17,826	8,303	132	9,625	201
7	R&PP Taxes - LVD	306	137,118	88,473	41,209	653	6,757	26
8	R&PP Taxes - PHFFU	316	8	5	2	0	1	0
9	R&PP Taxes -General, Common & Intangible	502	24,688	15,483	5,927	183	3,056	39
10	Total R&PP Taxes		280,500	161,584	74,733	1,211	42,283	688
11	Payroll and Miscellaneous Tax							
12	Payroll Related Taxes	502	25,343	15,893	6,084	188	3,137	40
13	Total Payroll/Miscellaneous Taxes		25,343	15,893	6,084	188	3,137	40
14	Other Taxes	150	11,296	4,239	2,421	55	4,523	58
15	Total Other Taxes		351,612	198,589	92,507	1,921	57,561	1,034
16	Federal Income Tax	439	46,009	22,699	12,458	637	9,881	334
17	Total Taxes Other Than Income		318,289	182,148	83,484	1,460	50,404	792
18	Total Income Taxes		79,333	39,140	21,480	1,098	17,037	577
19	**Total Taxes**		397,622	221,289	104,965	2,558	67,442	1,368

INCOME STATEMENT ADJUSTMENTS

1	**Other Adjustments to the Income Statement**							
2	AFUDC	330	16,026	9,224	4,164	74	2,526	38
3	**Total Other Adjustments**		16,026	9,224	4,164	74	2,526	38

ADDITIONAL REVENUE REQUIREMENTS

1	**Additional Revenue Requirements**							
2	Campbell Rev Req Adjustment	220	77,486	37,910	18,574	219	20,485	298

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-21870
Exhibit No.: A-16 (LMC-1)
Schedule: F-2.0
Page: 1 of 3
Witness: LMConnolly
Date: June 2025

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	$ 2,354,768	$ 2,668,590	$ 313,822	13.3
2	Smart Hours RSH	24,351	177,999	34,358	38,992	4,634	13.5
3	Night Time Savers RPM	16,879	168,382	31,182	36,027	4,845	15.5
4	Non-Transmitting Meters RSM	10,973	108,263	20,935	23,528	2,594	12.4
5	Total Residential Class	1,680,798	12,685,410	$ 2,441,242	$ 2,767,137	$ 325,894	13.3
	Secondary Class						
6	Energy-only GS	204,973	4,043,300	$ 708,149	$ 765,740	$ 57,591	8.1
7	Time-of-Use GSTU	1,891	83,093	14,429	15,700	1,271	8.8
8	Demand GSD	20,152	2,927,804	439,345	479,960	40,616	9.2
9	Total Secondary	227,015	7,054,196	$ 1,161,922	$ 1,261,399	$ 99,478	8.6
	Primary Class						
10	Energy-only GP	1,360	659,010	$ 78,248	$ 80,627	$ 2,380	3.0
11	Demand GPD	855	4,994,897	466,221	466,318	98	0.0
12	Time-of-Use GPTU	1,517	4,243,508	455,638	448,887	(6,751)	(1.5)
13	Energy Intensive EIP	17	392,565	30,152	31,211	1,059	3.5
14	Total Primary	3,748	10,289,980	$ 1,030,259	$ 1,027,044	$ (3,215)	(0.3)
	Lighting & Unmetered Class						
15	Metered Lighting GML	399	10,777	$ 1,622	$ 1,984	$ 361	22.3
16	Universal Unmetered Lighting UUL	4,696	54,640	28,563	33,306	4,743	16.6
17	Unmetered GU	465	97,806	10,668	11,459	790	7.4
18	Total Lighting & Unmetered	5,560	163,223	$ 40,854	$ 46,748	$ 5,894	14.4
	Self-generation Class						
19	Small Self-generation GSG-1	-	-	$ -	$ -	$ -	NA
20	Large Self-generation GSG-2	14	173,301	18,902	19,631	730	3.9
21	Total Self-generation	14	173,301	$ 18,902	$ 19,631	$ 730	3.9
22	Total Full Service	1,917,135	30,366,111	$ 4,693,179	$ 5,121,959	$ 428,781	9.1
	ROA SERVICE						
	Secondary Class						
23	Energy-only GS	85	18,386	$ 1,171	$ 1,394	$ 223	19.0
24	Demand GSD	472	171,253	8,809	11,128	2,320	26.3
25	Total Secondary	556	189,639	$ 9,980	$ 12,522	$ 2,542	25.5
	Primary Class						
26	Energy-only GP	60	71,144	$ 1,795	$ 1,903	$ 108	6.0
27	Demand GPD	356	3,291,840	28,853	33,295	4,441	15.4
28	Total Primary	417	3,362,984	$ 30,648	$ 35,198	$ 4,550	14.8
29	Total ROA Service	973	3,552,623	$ 40,628	$ 47,720	$ 7,092	17.5
30	Total Jurisdictional Service	1,918,108	33,918,734	$ 4,733,807	$ 5,169,679	$ 435,873	9.2
31	Plus: Rounding			-	5	8	
32	Total Jurisdictional Revenues			$ 4,733,807	$ 5,169,684	$ 435,877	9.2
33	Less: PSCR Factor Revenues			299,717	299,717	-	
34	Less: DR Surcharge			-	51,902	51,902	
35	Less: IRM Surcharge			-	22,244	22,244	
36	Total Jurisdictional Base Revenues			$ 4,434,089	$ 4,795,821	$ 361,732	8.2
37	Total Jurisdictional Revenues			4,733,807	5,169,684	435,877	9.2
38	Plus: ERC Deferral Surcharge			-	24,327	24,327	
39	Total Jurisdictional Revenues Requested			$ 4,733,807	$ 5,194,011	$ 460,204	9.7

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-21870
Exhibit No.: A-16 (LMC-1)
Schedule: F-2.0
Page: 2 of 3
Witness: LMConnolly
Date: June 2025

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	$ 1,258,272	$ 1,297,922	$ 39,650	3.2
2	Smart Hours RSH	177,999	18,266	18,898	632	3.5
3	Night Time Savers RPM	168,382	16,477	17,536	1,059	6.4
4	Non-Transmitting Meters RSM	108,263	11,213	11,363	151	1.3
5	Total Residential Class	12,685,410	$ 1,304,227	$ 1,345,719	$ 41,492	3.2
	Secondary Class					
6	Energy-only GS	4,043,300	$ 403,642	$ 412,039	$ 8,398	2.1
7	Time-of-Use GSTU	83,093	8,726	8,986	260	3.0
8	Demand GSD	2,927,804	281,455	282,335	880	0.3
9	Total Secondary	7,054,196	$ 693,823	$ 703,361	$ 9,538	1.4
	Primary Class					
10	Energy-only GP	659,010	$ 60,652	$ 62,030	$ 1,378	2.3
11	Demand GPD	4,994,897	409,983	404,438	(5,545)	(1.4)
12	Time-of-Use GPTU	4,243,508	374,116	363,649	(10,466)	(2.8)
13	Energy Intensive EIP	392,565	27,890	27,806	(84)	(0.3)
14	Total Primary	10,289,980	$ 872,641	$ 857,924	$ (14,717)	(1.7)
	Lighting & Unmetered Class					
15	Metered Lighting GML	10,777	$ 639	$ 590	$ (50)	(7.8)
16	Universal Unmetered Lighting UUL	54,640	3,127	2,821	(306)	(9.8)
17	Unmetered GU	97,806	7,876	7,825	(51)	(0.6)
18	Total Lighting & Unmetered	163,223	$ 11,642	$ 11,235	$ (407)	(3.5)
	Self-generation Class					
19	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
20	Large Self-generation GSG-2	173,301	15,956	15,956	-	-
21	Total Self-generation	173,301	$ 15,956	$ 15,956	$ -	-
22	Total Full Service	30,366,111	$ 2,898,288	$ 2,934,195	$ 35,906	1.2
	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	30,366,111	$ 2,898,288	$ 2,934,195	$ 35,906	1.2
31	Plus: Rounding		-	4	4	
32	Total Jurisdictional Base Revenues		$ 2,898,288	$ 2,934,199	$ 35,910	1.2
33	Less: PSCR Factor Revenues		299,717	299,717	-	
34	Less: DR Surcharge		-	51,902	51,902	
35	Less: IRM Surcharge		-	-	-	
36	Total Jurisdictional Base Revenues		$ 2,598,571	$ 2,582,579	$ (15,992)	(0.6)
37	Total Jurisdictional Revenues		2,898,288	2,934,199	35,910	1.2
38	Plus: ERC Deferral Surcharge		-	-	-	
39	Total Jurisdictional Revenues Requested		$ 2,898,288	$ 2,934,199	$ 35,910	1.2

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-21870
Exhibit No.: A-16 (LMC-1)
Schedule: F-2.0
Page: 3 of 3
Witness: LMConnolly
Date: June 2025

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	$ 1,370,668	$ 274,172	25.0
2	Smart Hours RSH	177,999	16,093	20,094	4,002	24.9
3	Night Time Savers RPM	168,382	14,705	18,490	3,786	25.7
4	Non-Transmitting Meters RSM	108,263	9,722	12,165	2,443	25.1
5	Total Residential Class	12,685,410	$ 1,137,016	$ 1,421,418	$ 284,402	25.0
	Secondary Class					
6	Energy-only GS	4,043,300	$ 304,507	$ 353,700	$ 49,193	16.2
7	Time-of-Use GSTU	83,093	5,702	6,714	1,011	17.7
8	Demand GSD	2,927,804	157,889	197,625	39,735	25.2
9	Total Secondary	7,054,196	$ 468,099	$ 558,039	$ 89,940	19.2
	Primary Class					
10	Energy-only GP	659,010	$ 17,595	$ 18,597	$ 1,002	5.7
11	Demand GPD	4,994,897	56,238	61,880	5,642	10.0
12	Time-of-Use GPTU	4,243,508	81,523	85,238	3,715	4.6
13	Energy Intensive EIP	392,565	2,262	3,405	1,142	50.5
14	Total Primary	10,289,980	$ 157,618	$ 169,119	$ 11,502	7.3
	Lighting & Unmetered Class					
15	Metered Lighting GML	10,777	$ 983	$ 1,394	$ 411	41.8
16	Universal Unmetered Lighting UUL	54,640	25,436	30,485	5,049	19.8
17	Unmetered GU	97,806	2,792	3,634	842	30.1
18	Total Lighting & Unmetered	163,223	$ 29,212	$ 35,513	$ 6,301	21.6
	Self-generation Class					
19	Small Self-generation GSG-1	-	$ -	$ -	$ -	NA
20	Large Self-generation GSG-2	173,301	2,946	3,675	730	24.8
21	Total Self-generation	173,301	$ 2,946	$ 3,675	$ 730	24.8
22	Total Full Service	30,366,111	$ 1,794,890	$ 2,187,764	$ 392,874	21.9
	ROA SERVICE					
	Secondary Class					
23	Energy-only GS	18,386	$ 1,171	$ 1,394	$ 223	19.0
24	Demand GSD	171,253	8,809	11,128	2,320	26.3
25	Total Secondary	189,639	$ 9,980	$ 12,522	$ 2,542	25.5
	Primary Class					
26	Energy-only GP	71,144	$ 1,795	$ 1,903	$ 108	6.0
27	Demand GPD	3,291,840	28,853	33,295	4,441	15.4
28	Total Primary	3,362,984	$ 30,648	$ 35,198	$ 4,550	14.8
29	Total ROA Service	3,552,623	$ 40,628	$ 47,720	$ 7,092	17.5
30	Total Jurisdictional Service	33,918,734	$ 1,835,518	$ 2,235,485	$ 399,966	21.8
31	Plus: Rounding		-	1	1	
32	Total Jurisdictional Base Revenues		$ 1,835,518	$ 2,235,486	$ 399,967	21.8
33	Less: PSCR Factor Revenues		-	-	-	
34	Less: DR Surcharge		-	-	-	
35	Less: IRM Surcharge		-	22,244	22,244	
36	Total Jurisdictional Base Revenues		$ 1,835,518	$ 2,213,242	$ 377,724	20.6
37	Total Jurisdictional Revenues		1,835,518	2,235,486	399,967	21.8
38	Plus: ERC Deferral Surcharge		-	24,327	24,327	
39	Total Jurisdictional Revenues Requested		$ 1,835,518	$ 2,259,813	$ 424,294	23.1

Schedule F-2.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Rate Design Targets
($000)

Case No.: U-21870
Exhibit No.: A-16 (LMC-2)
Schedule: F-2.1
Page: 1 of 1
Witness: LMConnolly
Date: June 2025

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)	$ 417,794	$ 212,965	$ 61,392	$ 39,011	$ 8,184	$ 46,163	$ 44,845	$ 3,065	$ 3	$ -	$ 801	$ -	$ 1,364	
	Capacity Adjustments [1]														
2	DR Revenue Requirement	(43,572)	(21,400)	(6,342)	(4,143)	(877)	(5,321)	(4,987)	(378)	(4)	(20)	(99)	-	-	WP-LMC-7
3	Self Generation	-	517	149	95	20	112	109	7	0	-	2	-	(1,011)	Alloc. Line 1
4	Total Adjustments	(43,572)	(20,883)	(6,193)	(4,048)	(858)	(5,209)	(4,878)	(370)	(4)	(20)	(97)	-	(1,011)	
5	Capacity (SRM) Design Target	$ 374,222	$ 192,082	$ 55,199	$ 34,963	$ 7,327	$ 40,954	$ 39,966	$ 2,695	$ (1)	$ (20)	$ 704	$ -	$ 353	
6	Energy [2]	$ 1,584,824	$ 715,442	$ 228,248	$ 155,833	$ 34,145	$ 231,289	$ 201,815	$ 18,189	$ 374	$ 1,884	$ 4,620	$ -	$ (7,015)	
	Energy Adjustments [1]														
7	Self Generation	-	(3,153)	(1,006)	(687)	(150)	(1,019)	(889)	(80)	(2)	(8)	(20)	-	7,015	Alloc. Line 6
8	Total Adjustments	-	(3,153)	(1,006)	(687)	(150)	(1,019)	(889)	(80)	(2)	(8)	(20)	-	7,015	
9	Energy Design Target	$ 1,584,824	$ 712,289	$ 227,242	$ 155,147	$ 33,995	$ 230,270	$ 200,925	$ 18,108	$ 372	$ 1,876	$ 4,600	$ -	$ -	
10	Total Production	$ 1,959,046	$ 904,371	$ 282,441	$ 190,110	$ 41,322	$ 271,223	$ 240,892	$ 20,803	$ 371	$ 1,856	$ 5,304	$ -	$ 353	
11	**Transmission**														
12	Transmission	631,863	297,311	91,856	60,142	13,412	82,007	76,598	6,157	111	429	1,476	-	2,363	
13	Self Generation	-	1,116	345	226	50	308	288	23	0	2	6	-	(2,363)	Alloc. Line 12
14	Transmission Design Target	$ 631,863	$ 298,428	$ 92,201	$ 60,368	$ 13,462	$ 82,315	$ 76,886	$ 6,180	$ 112	$ 430	$ 1,482	$ -	$ -	
	Delivery														
15	Distribution [3]	$ 1,955,942	$ 1,223,487	$ 316,549	$ 194,456	$ 16,826	$ 93,696	$ 72,294	$ 2,463	$ 1,289	$ 28,555	$ 3,508	$ -	$ 2,818	
16	Customer	257,305	194,147	37,135	9,404	3,062	5,877	5,906	149	79	1,349	85	-	113	
17	Subtotal Delivery	2,213,247	1,417,634	353,684	203,860	19,888	99,573	78,200	2,612	1,368	29,904	3,593	-	2,931	
	Credit Adjustments [4]														
18	Substation Credits	$ -	$ 1,814	$ 469	$ 288	$ (8)	$ (1,388)	$ (344)	$ (322)	$ 2	$ 42	$ 5	$ -	$ (558)	WP-LMC-12
19	Life Line Credits	0	(12,276)	4,098	2,557	421	2,553	2,231	167	10	239	-	-	-	WP-LMC-9
20	Total Adjustments	0	(10,462)	4,568	2,845	412	1,164	1,887	(155)	12	281	5	-	(558)	
21	Total Delivery Design Target	$ 2,213,247	$ 1,407,172	$ 358,252	$ 206,705	$ 20,300	$ 100,737	$ 80,087	$ 2,457	$ 1,380	$ 30,186	$ 3,598	$ -	$ 2,373	
22	Total Rate Design Target	$ 4,804,156	$ 2,609,971	$ 732,893	$ 457,182	$ 75,084	$ 454,276	$ 397,865	$ 29,441	$ 1,863	$ 32,472	$ 10,384	$ -	$ 2,725	
23	DR Surcharge	$ 51,902	$ 25,491	$ 7,555	$ 4,935	$ 1,045	$ 6,338	$ 5,941	$ 450	$ 5	$ 24	$ 118	$ -	$ -	WP-LMC-19
24	IRM Surcharge	$ 22,239	$ 14,246	$ 3,556	$ 2,048	$ 200	$ 1,083	$ 706	$ 31	$ 14	$ 301	$ 36	$ -	$ 18	A-68 (LMC-7)
25	Total Revenue Requirement	$ 4,878,297	$ 2,649,707	$ 744,004	$ 464,166	$ 76,329	$ 461,697	$ 404,512	$ 29,922	$ 1,882	$ 32,796	$ 10,538	$ -	$ 2,743	

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	814,657	MWh	@	0.103708	$ 84,486	0.091073	$ 74,193	$ (10,293)
2	Off-peak kWh	3,560,451	MWh	@	0.067729	241,147	0.062334	221,937	(19,210)
	Capacity								
3	On-peak kWh	814,657	MWh	@	0.011465	9,340	0.024560	20,008	10,668
4	Off-peak kWh	3,560,451	MWh	@	0.007706	27,436	0.016810	59,850	32,414
	Winter (Oct. - May)								
5	Non-capacity All kWh	7,855,392	MWh	@	0.060714	476,935	0.049760	390,882	(86,053)
6	Capacity All kWh	7,855,392	MWh	@	0.006004	47,163	0.013419	105,409	58,246
	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		$ 985,507	$ (13,656)
	Transmission								
	Summer (June - Sept.)								
15	On-peak kWh	814,657	MWh	@	0.035390	$ 28,831	0.038157	$ 31,085	$ 2,254
16	Off-peak kWh	3,560,451	MWh	@	0.023787	84,692	0.026116	92,985	8,293
	Winter (Oct. - May)								
17	All kWh	7,855,392	MWh	@	0.018533	145,586	0.020848	163,768	18,181
18	Total Transmission					$ 259,109		$ 287,837	$ 28,729
	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	0.100314	1,226,919	261,234
	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		$ 1,356,933	$ 260,437
25	Total Full Service					$ 2,354,768		$ 2,630,278	$ 275,510
	ROA SERVICE								
	Delivery								
26	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
27	Distribution	-	MWh	@	0.078955	-	0.100314	-	-
	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		$ 2,630,278	$ 275,510

(1) Proposed revenue reflects change to 3 months

0.11700074

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Smart Hours (RSH)

Case No.: U-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	11,637	MWh	@	0.103708	$ 1,207	0.091073	$ 1,060	$ (147)
2	Off-peak kWh	54,082	MWh	@	0.067729	3,663	0.062334	3,371	(292)
	Capacity								
3	On-peak kWh	11,637	MWh	@	0.011465	133	0.024560	286	152
4	Off-peak kWh	54,082	MWh	@	0.007706	417	0.016810	909	492
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kWh	17,187	MWh	@	0.068308	1,174	0.057793	993	(181)
6	Off-peak kWh	95,088	MWh	@	0.059219	5,631	0.048225	4,586	(1,045)
	Capacity								
7	On-peak kWh	17,187	MWh	@	0.006611	114	0.015585	268	154
8	Off-peak kWh	95,088	MWh	@	0.005812	553	0.013005	1,237	684
	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		$ 14,346	$ (165)
	Transmission								
	Summer (June - Sept.)								
17	On-peak kWh	11,637	MWh	@	0.035390	$ 412	0.038157	$ 444	$ 32
18	Off-peak kWh	54,082	MWh	@	0.023787	1,286	0.026116	1,412	126
	Winter (Oct. - May)								
19	On-peak kWh	17,187	MWh	@	0.020408	351	0.024214	416	65
20	Off-peak kWh	95,088	MWh	@	0.017940	1,706	0.020205	1,921	215
21	Total Transmission					$ 3,755		$ 4,194	$ 439
	Delivery								
22	System Access	292,217	Bills	@	8.00	$ 2,338	8.00	$ 2,338	$ -
23	Distribution	177,999	MWh	@	0.078955	14,054	0.100314	17,856	3,802
	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		$ 19,894	$ 3,802
28	Total Full Service					$ 34,358		$ 38,434	$ 4,076
	ROA SERVICE								
	Delivery								
29	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
30	Distribution	-	MWh	@	0.078955	-	0.100314	-	-
	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		$ 38,434	$ 4,076

(1) Proposed revenue reflects change to 3 months

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Nighttime Savers (RPM)

Case No.: U-21870
Exhibit No.: A-16 (LMC-3)
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Witness: LMConnolly
Date: June 2025

	(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								
	Summer (June - Sept.)								
	Non-capacity								
1	On-peak kWh	9,384	MWh	@	0.103708	$ 973	0.091073	$ 855	$ (119)
2	Off-peak kWh	19,685	MWh	@	0.075937	1,495	0.069643	1,371	(124)
3	Super Off-peak kWh	33,466	MWh	@	0.060380	2,021	0.056354	1,886	(135)
	Capacity								
4	On-peak kWh	9,384	MWh	@	0.011465	108	0.024560	230	123
5	Off-peak kWh	19,685	MWh	@	0.008693	171	0.018781	370	199
6	Super Off-peak kWh	33,466	MWh	@	0.005292	177	0.015197	509	331
	Winter (Oct. - May)								
	Non-capacity								
7	On-peak kWh	13,591	MWh	@	0.068308	928	0.057793	785	(143)
8	Off-peak kWh	33,262	MWh	@	0.066685	2,218	0.054213	1,803	(415)
9	Super Off-peak kWh	58,994	MWh	@	0.052649	3,106	0.043554	2,569	(537)
	Capacity								
10	On-peak kWh	13,591	MWh	@	0.006611	90	0.015585	212	122
11	Off-peak kWh	33,262	MWh	@	0.006392	213	0.014619	486	274
12	Super Off-peak kWh	58,994	MWh	@	0.004585	270	0.011745	693	422
	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		$ 13,314	$ 13
	Transmission								
	Summer (June - Sept.)								
21	On-peak kWh	9,384	MWh	@	0.035390	$ 332	0.038157	$ 358	$ 26
22	Off-peak kWh	19,685	MWh	@	0.026835	528	0.029179	574	46
23	Super Off-peak kWh	33,466	MWh	@	0.016336	547	0.023611	790	243
	Winter (Oct. - May)								
24	On-peak kWh	13,591	MWh	@	0.020408	277	0.024214	329	52
25	Off-peak kWh	33,262	MWh	@	0.019733	656	0.022713	755	99
26	Super Off-peak kWh	58,994	MWh	@	0.014153	835	0.018248	1,077	242
27	Total Transmission					$ 3,176		$ 3,884	$ 708
	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	0.100314	16,891	3,596
	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		$ 18,301	$ 3,596
35	Total Full Service					$ 31,182		$ 35,499	$ 4,317
	ROA SERVICE								
	Delivery								
36	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
37	Distribution	-	MWh	@	0.078955	-	0.100314	-	-
	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		$ 35,499	$ 4,317

(1) Proposed revenue reflects change to 3 months

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Residential Non-Transmitting Meters (RSM)

Case No.: U-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	First 600 kWh	23,089	MWh	@	0.060714	$ 1,402	0.049760	$ 1,149	$ (253)
2	Excess kWh	14,767	MWh	@	0.103708	1,531	0.091073	1,345	(187)
	Capacity								
3	First 600 kWh	23,089	MWh	@	0.006004	139	0.013419	310	171
4	Excess kWh	14,767	MWh	@	0.011465	169	0.024560	363	193
	Winter (Oct. - May)								
5	Non-capacity All kWh	70,407	MWh	@	0.060714	4,275	0.049760	3,503	(771)
6	Capacity All kWh	70,407	MWh	@	0.006004	423	0.013419	945	522
7	Annual PSCR Factor	108,263	MWh	@	0.009410	1,019	0.009410	1,019	-
8	Total Production					$ 8,957		$ 8,633	$ (324)
	Transmission								
	Summer (June - Sept.)								
9	First 600 kWh	23,089	MWh	@	0.018533	$ 428	0.020848	$ 481	$ 53
10	Excess kWh	14,767	MWh	@	0.035390	523	0.038157	563	41
	Winter (Oct. - May)								
11	All kWh	70,407	MWh	@	0.018533	1,305	0.020848	1,468	163
12	Total Transmission					$ 2,255		$ 2,513	$ 257
	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	3.09	312	9
15	Distribution	108,263	MWh	@	0.078955	8,548	0.100314	10,860	2,312
	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		$ 12,043	$ 2,321
20	Total Full Service					$ 20,935		$ 23,189	$ 2,255
	ROA SERVICE								
	Delivery								
21	System Access	-	Bills	@	8.00	$ -	8.00	$ -	$ -
22	Opt-out Fee	-	Bills	@	3.00	-	3.09	-	-
23	Distribution	-	MWh	@	0.078955	-	0.100314	-	-
	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		$ 23,189	$ 2,255

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Energy-only (GS)

Case No.: U-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	1,422,528	MWh	@	0.072639	$ 103,331	0.066474	$ 94,561	$ (8,770)
2	Capacity All kWh	1,422,528	MWh	@	0.007743	11,014	0.016049	22,830	11,815
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,620,772	MWh	@	0.059380	155,622	0.048767	127,807	(27,815)
4	Capacity All kWh	2,620,772	MWh	@	0.005420	14,204	0.011897	31,179	16,975
5	Annual PSCR Factor	4,043,300	MWh	@	0.009410	38,047	0.009410	38,047	-
6	Total Production					$ 322,219		$ 314,424	$ (7,794)
	Transmission								
	Summer (June - Sept.)								
7	All kWh	1,422,528	MWh	@	0.025000	$ 35,563	0.026807	$ 38,133	$ 2,570
	Winter (Oct. - May)								
8	All kWh	2,620,772	MWh	@	0.017499	45,860	0.019872	52,080	6,219
9	Total Transmission					$ 81,423		$ 90,213	$ 8,790
	Delivery								
10	System Access	2,459,675	Bills	@	20.00	$ 49,193	20.00	$ 49,193	$ -
11	Distribution	4,043,300	MWh	@	0.063166	255,400	0.074477	301,132	45,732
	Provisions								
12	Education GEI	94,145	MWh	@	(0.000923)	(87)	(0.001009)	(95)	(8)
13	Total Delivery					$ 304,507		$ 350,231	$ 45,724
14	Total Full Service					$ 708,149		$ 754,868	$ 46,719
	ROA SERVICE								
	Delivery								
15	System Access	1,014	Bills	@	20.00	$ 20	20.00	$ 20	$ -
16	Distribution	18,386	MWh	@	0.063166	1,161	0.074477	1,369	208
	Provisions								
17	Education GEI	11,281	MWh	@	(0.000923)	(10)	(0.001009)	(11)	(1)
18	Total Delivery					$ 1,171		$ 1,378	$ 207
19	Total Full & ROA Service					$ 709,320		$ 756,246	$ 46,926

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Time-of-Use (GSTU)

Case No.: U-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	14,615	MWh	@		0.104236	$ 1,523	0.090085	$ 1,317	$ (207)
2	Mid-peak kWh	11,514	MWh	@		0.076824	885	0.070161	808	(77)
3	Off-peak kWh	4,409	MWh	@		0.058953	260	0.052611	232	(28)
	Capacity									
4	On-peak kWh	14,615	MWh	@		0.009395	137	0.021967	321	184
5	Mid-peak kWh	11,514	MWh	@		0.007806	90	0.017108	197	107
6	Off-peak kWh	4,409	MWh	@		0.005037	22	0.012847	57	34
	Winter (Oct. - May)									
	Non-capacity									
7	On-peak kWh	25,134	MWh	@		0.065715	1,652	0.053203	1,337	(314)
8	Off-peak kWh	27,422	MWh	@		0.052389	1,437	0.043055	1,181	(256)
	Capacity									
9	On-peak kWh	25,134	MWh	@		0.005876	148	0.013015	327	179
10	Off-peak kWh	27,422	MWh	@		0.004390	120	0.010512	288	168
	Provisions									
11	Interruptible (GSI)	-	MWh	@		(0.021295)	-	(0.021685)	-	-
12	Annual PSCR Factor	83,093	MWh	@		0.009410	782	0.009410	782	-
13	Total Production						$ 7,055		$ 6,846	$ (209)
	Transmission									
	Summer (June - Sept.)									
14	On-peak kWh	14,615	MWh	@		0.030333	$ 443	0.036692	$ 536	$ 93
15	Mid-peak kWh	11,514	MWh	@		0.025203	290	0.028576	329	39
16	Off-peak kWh	4,409	MWh	@		0.016265	72	0.021460	95	23
	Winter (Oct. - May)									
17	On-peak kWh	25,134	MWh	@		0.018972	477	0.021739	546	70
18	Off-peak kWh	27,422	MWh	@		0.014174	389	0.017558	481	93
19	Total Transmission						$ 1,671		$ 1,988	$ 317
	Delivery									
20	System Access	22,689	Bills	@		20.00	$ 454	20.00	$ 454	$ -
21	Distribution	83,093	MWh	@		0.063166	5,249	0.074477	6,189	940
	Provisions									
22	Education GEI	-	MWh	@		(0.000923)	-	(0.001009)	-	-
23	Total Delivery						$ 5,702		$ 6,642	$ 940
24	Total Full Service						$ 14,429		$ 15,476	$ 1,047

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Secondary Demand (GSD)

Case No.: U-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
Page: 7 of 23
Witness: LMConnolly
Date: June 2025

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	2,842	MW	@	18.04	$ 51,287	14.27	$ 40,573	$ (10,714)
2	All kWh	1,030,542	MWh	@	0.033424	34,445	0.032577	33,572	(873)
	Capacity								
3	Peak kW	2,842	MW	@	2.17	6,168	4.65	13,213	7,045
4	All kWh	1,030,542	MWh	@	-	-	-	-	-
	Winter (Oct. - May)								
	Non-capacity								
5	Peak kW	5,245	MW	@	8.54	44,800	6.76	35,441	(9,359)
6	All kWh	1,897,262	MWh	@	0.027323	51,839	0.023899	45,342	(6,497)
	Capacity								
7	Peak kW	5,245	MW	@	1.93	10,131	4.14	21,701	11,570
8	All kWh	1,897,262	MWh	@	-	-	-	-	-
9	Power Factor Adjustment					159		268	109
	Provisions								
10	Interruptible (GSI)-Summer	28	MW	@	(8.50)	(238)	(8.50)	(238)	-
11	Interruptible (GSI)-Winter	52	MW	@	(7.50)	(390)	(7.50)	(390)	-
12	Annual PSCR Factor	2,927,804	MWh	@	0.009410	27,551	0.009410	27,551	-
13	Total Production					$ 225,751		$ 217,033	$ (8,719)
	Transmission								
	Summer (June - Sept.)								
14	Peak kW	2,842	MW	@	7.42	$ 21,081	8.04	$ 22,846	$ 1,765
	Winter (Oct. - May)								
15	Peak kW	5,245	MW	@	6.60	34,623	7.15	37,522	2,899
16	Total Transmission					$ 55,704		$ 60,368	$ 4,664
	Delivery								
17	System Access	241,823	Bills	@	30.00	$ 7,255	30.00	$ 7,255	$ -
18	Peak kW	8,088	MW	@	1.00	8,088	1.00	8,088	-
19	Distribution	2,927,804	MWh	@	0.048648	142,430	0.061544	180,188	37,757
20	Power Factor Adjustment					212		266	53
	Provisions								
21	Education GEI	128,833	MWh	@	(0.000745)	(96)	(0.000825)	(106)	(10)
22	Total Delivery					$ 157,889		$ 195,690	$ 37,800
23	Total Full Service					$ 439,345		$ 473,090	$ 33,745
	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	171,253	MWh	@	0.048648	8,331	0.061544	10,540	2,208
27	Power Factor Adjustment					13		16	3
	Provisions								
28	Education GEI	67,012	MWh	@	(0.000745)	(50)	(0.000825)	(55)	(5)
29	Total Delivery					$ 8,809		$ 11,015	$ 2,206
30	Total Full & ROA Service					$ 448,153		$ 484,105	$ 35,952

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
Page: 8 of 23
Witness: LMConnolly
Date: June 2025

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	1,088	MWh	@	0.064501	$ 70	0.060335	$ 66	$ (5)
2	Capacity All kWh	1,088	MWh	@	0.006228	7	0.012607	14	7
	Winter (Oct. - May)								
3	Non-capacity All kWh	2,324	MWh	@	0.052728	123	0.044263	103	(20)
4	Capacity All kWh	2,324	MWh	@	0.004359	10	0.009616	22	12
5	Power Factor Adjustment					3		3	(0)
6	Annual PSCR Factor	3,413	MWh	@	0.009410	32	0.009410	32	-
7	Total Production					$ 245		$ 240	$ (5)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	1,088	MWh	@	0.022500	$ 24	0.023468	$ 26	$ 1
	Winter (Oct. - May)								
9	All kWh	2,324	MWh	@	0.015749	37	0.017902	42	5
10	Total Transmission					$ 61		$ 67	$ 6
	Delivery								
11	System Access	49	Bills	@	100.00	$ 5	100.00	$ 5	$ -
12	Distribution	3,413	MWh	@	0.002918	10	0.007451	25	15
13	Substation Ownership Credit	692	MWh	@	(0.001438)	(1)	(0.004114)	(3)	(2)
14	Power Factor Adjustment					0		0	0
	Provisions								
15	Education GEI	-	MWh	@	(0.000558)	-	(0.000576)	-	-
16	Total Delivery					$ 14		$ 28	$ 14
17	Total Full Service					$ 320		$ 335	$ 15
	ROA SERVICE								
	Delivery								
18	System Access	-	Bills	@	100.00	$ -	100.00	$ -	$ -
19	Distribution	-	MWh	@	0.002918	-	0.007451	-	-
20	Substation Ownership Credit	-	MWh	@	(0.001438)	-	(0.004114)	-	-
21	Power Factor Adjustment					-		-	-
	Provisions								
22	Education GEI	-	MWh	@	(0.000558)	-	(0.000576)	-	-
23	Total Delivery					$ -		$ -	$ -
24	Total Full & ROA Service					$ 320		$ 335	$ 15

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	9,372	MWh	@		0.065275	$ 612	0.061041	$ 572	$ (40)
2	Capacity All kWh	9,372	MWh	@		0.006319	59	0.012791	120	61
	Winter (Oct. - May)									
3	Non-capacity All kWh	21,515	MWh	@		0.053361	1,148	0.044781	963	(185)
4	Capacity All kWh	21,515	MWh	@		0.004423	95	0.009757	210	115
5	Power Factor Adjustment						50		49	(1)
6	Annual PSCR Factor	30,887	MWh	@		0.009410	291	0.009410	291	-
7	Total Production						$ 2,255		$ 2,205	$ (50)
	Transmission									
	Summer (June - Sept.)									
8	All kWh	9,372	MWh	@		0.022831	$ 214	0.023811	$ 223	$ 9
	Winter (Oct. - May)									
9	All kWh	21,515	MWh	@		0.015981	344	0.018163	391	47
10	Total Transmission						$ 558		$ 614	$ 56
	Delivery									
11	System Access	435	Bills	@		100.00	$ 43	100.00	$ 43	$ -
12	Distribution	30,887	MWh	@		0.010731	331	0.011747	363	31
13	Substation Ownership Credit	6,501	MWh	@		(0.001925)	(13)	(0.004541)	(30)	(17)
14	Power Factor Adjustment						8		9	0
	Provisions									
15	Education GEI	-	MWh	@		(0.000558)	-	(0.000576)	-	-
16	Total Delivery						$ 371		$ 385	$ 15
17	Total Full Service						$ 3,184		$ 3,204	$ 21
	ROA SERVICE									
	Delivery									
18	System Access	24	Bills	@		100.00	$ 2	100.00	$ 2	$ -
19	Distribution	1,760	MWh	@		0.010731	19	0.011747	21	2
20	Substation Ownership Credit	-	MWh	@		(0.001925)	-	(0.004541)	-	-
21	Power Factor Adjustment						(0)		(0)	(0)
	Provisions									
22	Education GEI	-	MWh	@		(0.000558)	-	(0.000576)	-	-
23	Total Delivery						$ 21		$ 23	$ 2
24	Total Full & ROA Service						$ 3,205		$ 3,227	$ 23

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	218,636	MWh	@	0.065920	$ 14,413	0.061657	$ 13,480	$ (932)
2	Capacity All kWh	218,636	MWh	@	0.006408	1,401	0.012994	2,841	1,440
	Winter (Oct. - May)								
3	Non-capacity All kWh	406,073	MWh	@	0.053888	21,882	0.045233	18,368	(3,515)
4	Capacity All kWh	406,073	MWh	@	0.004485	1,821	0.009912	4,025	2,204
5	Power Factor Adjustment					496		486	(10)
6	Annual PSCR Factor	624,710	MWh	@	0.009410	5,879	0.009410	5,879	-
7	Total Production					$ 45,892		$ 45,078	$ (814)
	Transmission								
	Summer (June - Sept.)								
8	All kWh	218,636	MWh	@	0.023151	$ 5,062	0.024189	$ 5,289	$ 227
	Winter (Oct. - May)								
9	All kWh	406,073	MWh	@	0.016204	6,580	0.018451	7,493	912
10	Total Transmission					$ 11,642		$ 12,781	$ 1,139
	Delivery								
11	System Access	15,834	Bills	@	100.00	$ 1,583	100.00	$ 1,583	$ -
12	Distribution	624,710	MWh	@	0.024779	15,480	0.026035	16,264	785
13	Power Factor Adjustment					194		204	10
	Provisions								
14	Education GEI	84,089	MWh	@	(0.000558)	(47)	(0.000576)	(48)	(2)
15	Total Delivery					$ 17,211		$ 18,003	$ 793
16	Total Full Service					$ 74,744		$ 75,863	$ 1,119
	ROA SERVICE								
	Delivery								
17	System Access	696	Bills	@	100.00	$ 70	100.00	$ 70	$ -
18	Distribution	69,383	MWh	@	0.024779	1,719	0.026035	1,806	87
19	Power Factor Adjustment					5		6	0
	Provisions								
20	Education GEI	36,417	MWh	@	(0.000558)	(20)	(0.000576)	(21)	(1)
21	Total Delivery					$ 1,774		$ 1,861	$ 87
22	Total Full & ROA Service					$ 76,518		$ 77,723	$ 1,205

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	662	MW	@	14.98	$ 9,922	12.04	$ 7,969	$ (1,952)
2	On-peak kWh	85,525	MWh	@	0.042727	3,654	0.040641	3,476	(178)
3	Off-peak kWh	293,687	MWh	@	0.027682	8,130	0.026358	7,741	(389)
4	Capacity On-peak kW	662	MW	@	2.17	1,434	4.57	3,029	1,595
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	1,358	MW	@	12.94	17,581	10.40	14,121	(3,459)
6	On-peak kWh	177,818	MWh	@	0.029145	5,183	0.025486	4,532	(651)
7	Off-peak kWh	601,128	MWh	@	0.025104	15,091	0.022129	13,302	(1,788)
8	Capacity On-peak kW	1,358	MW	@	2.01	2,728	4.24	5,761	3,033
	Provisions								
9	Economic Development GED	-	MW	@	-	-	-	-	-
	Interruptible GI								
10	Summer Contracted kW	60	MW	@	(8.50)	(509)	(8.50)	(509)	-
11	Winter Contracted kW	120	MW	@	(7.50)	(898)	(7.50)	(898)	-
	Interruptible GI-2								
12	Summer Capacity & Transmission	-	MWh	@	0.029172	-	0.030167	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.026113	-	0.027326	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.029002	-	-
16	Summer Transmission	-	MWh		-	-	0.016007	-	-
17	Winter Capacity	-	MWh		-	-	0.025524	-	-
18	Winter Transmission	-	MWh		-	-	0.014879	-	-
19	Critical Peak Event	-	MWh		-	-	1.00	-	-
20	Power Factor Adjustment					(131)		(123)	8
21	Annual PSCR Factor	1,158,158	MWh	@	0.009410	10,898	0.009410	10,898	-
22	Total Production					$ 73,083		$ 69,300	$ (3,782)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	662	MW	@	8.63	$ 5,716	9.17	$ 6,070	$ 354
	Winter (Oct. - May)								
24	On-peak kW	1,358	MW	@	8.04	10,914	8.53	11,590	676
25	Total Transmission					$ 16,630		$ 17,660	$ 1,030
	Delivery								
26	System Access	267	Bills	@	200.00	$ 53	200.00	$ 53	$ -
27	Maximum kW	2,507	MW	@	1.02	2,551	2.53	6,347	3,796
28	Substation Ownership	42	MW	@	(0.66)	(28)	(1.83)	(76)	(48)
29	Distribution	1,158,158	MWh	@	-	-	-	-	-
30	Power Factor Adjustment					(5)		(13)	(8)
	Provisions								
31	Education GEI	-	MWh	@	(0.000194)	-	(0.000204)	-	-
32	Total Delivery					$ 2,571		$ 6,312	$ 3,740
33	Total Full Service					$ 92,284		$ 93,272	$ 988
	ROA SERVICE								
	Delivery								
34	System Access	169	Bills	@	200.00	$ 34	200.00	$ 34	$ -
35	Maximum kW	2,403	MW	@	1.02	2,445	2.53	6,083	3,638
36	Substation Ownership	196	MW	@	(0.66)	(130)	(1.83)	(358)	(227)
37	Distribution	1,265,948	MWh	@	-	-	-	-	-
38	Power Factor Adjustment					(6)		(15)	(9)
	Provisions								
39	Education GEI	2,665	MWh	@	(0.000194)	(1)	(0.000204)	(1)	(0)
40	Total Delivery					$ 2,342		$ 5,744	$ 3,402
41	Total Full & ROA Service					$ 94,626		$ 99,016	$ 4,390

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	879	MW	@		15.16	$ 13,323	12.18	$ 10,698	$ (2,625)
2	On-peak kWh	120,090	MWh	@		0.043240	5,193	0.041117	4,938	(255)
3	Off-peak kWh	354,760	MWh	@		0.028014	9,938	0.026666	9,460	(478)
4	Capacity On-peak kW	879	MW	@		2.20	1,931	4.64	4,078	2,147
	Winter (Oct. - May)									
	Non-capacity									
5	On-peak kW	1,786	MW	@		13.10	23,402	10.52	18,791	(4,611)
6	On-peak kWh	238,958	MWh	@		0.029495	7,048	0.025784	6,161	(887)
7	Off-peak kWh	727,555	MWh	@		0.025405	18,484	0.022388	16,289	(2,195)
8	Capacity On-peak kW	1,786	MW	@		2.04	3,640	4.30	7,688	4,047
	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	@		0.031540	-	0.032600	-	-
13	Winter Capacity & Transmission	-	MWh	@		0.028315	-	0.029537	-	-
14	LMP	-	MWh	@		-	-	-	-	-
	Coincident Peak Provision									
15	Summer Capacity	-	MWh			-	-	0.031117	-	-
16	Summer Transmission	-	MWh			-	-	0.017210	-	-
17	Winter Capacity	-	MWh			-	-	0.027397	-	-
18	Winter Transmission	-	MWh			-	-	0.008455	-	-
19	Critical Peak Event	-	MWh			-	-	1.000000	-	-
20	Power Factor Adjustment						(110)		(104)	7
21	Annual PSCR Factor	1,441,363	MWh	@		0.009410	13,563	0.009410	13,563	-
22	Total Production						$ 95,468		$ 90,618	$ (4,850)
	Transmission									
	Summer (June - Sept.)									
23	On-peak kW	879	MW	@		8.76	$ 7,696	9.30	$ 8,172	$ 476
	Winter (Oct. - May)									
24	On-peak kW	1,786	MW	@		8.15	14,566	8.66	15,467	901
25	Total Transmission						$ 22,262		$ 23,639	$ 1,377
	Delivery									
26	System Access	721	Bills	@		200.00	$ 144	200.00	$ 144	$ -
27	Maximum kW	3,087	MW	@		3.50	10,798	3.84	11,840	1,042
28	Substation Ownership	267	MW	@		(0.83)	(222)	(1.94)	(517)	(295)
29	Distribution	1,441,363	MWh	@		-	-	-	-	-
30	Power Factor Adjustment						(14)		(15)	(1)
	Provisions									
31	Education GEI	29,495	MWh	@		(0.000194)	(6)	(0.000204)	(6)	(0)
32	Total Delivery						$ 10,700		$ 11,446	$ 746
33	Total Full Service						$ 128,430		$ 125,702	$ (2,727)
	ROA SERVICE									
	Delivery									
34	System Access	453	Bills	@		200.00	$ 91	200.00	$ 91	$ -
35	Maximum kW	2,306	MW	@		3.50	8,066	3.84	8,845	778
36	Substation Ownership	298	MW	@		(0.83)	(248)	(1.94)	(577)	(329)
37	Distribution	1,076,272	MWh	@		-	-	-	-	-
38	Power Factor Adjustment						16		17	1
	Provisions									
39	Education GEI	66,458	MWh	@		(0.000194)	(13)	(0.000204)	(14)	(1)
40	Total Delivery						$ 7,912		$ 8,361	$ 450
41	Total Full & ROA Service						$ 136,342		$ 134,064	$ (2,278)

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	1,501	MW	@	15.31	$ 22,990	12.30	$ 18,465	$ (4,526)
2	On-peak kWh	207,633	MWh	@	0.043667	9,067	0.041531	8,623	(443)
3	Off-peak kWh	582,471	MWh	@	0.028291	16,479	0.026935	15,689	(790)
4	Capacity On-peak kW	1,501	MW	@	2.23	3,346	4.71	7,078	3,733
	Winter (Oct. - May)								
	Non-capacity								
5	On-peak kW	3,050	MW	@	13.23	40,356	10.63	32,412	(7,944)
6	On-peak kWh	414,116	MWh	@	0.029787	12,335	0.026044	10,785	(1,550)
7	Off-peak kWh	1,191,156	MWh	@	0.025656	30,561	0.022614	26,936	(3,624)
8	Capacity On-peak kW	3,050	MW	@	2.07	6,303	4.37	13,336	7,033
	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	@	0.032871	-	0.034131	-	-
13	Winter Capacity & Transmission	-	MWh	@	0.030146	-	0.032201	-	-
14	LMP	-	MWh	@	-	-	-	-	-
	Coincident Peak Provision								
15	Summer Capacity	-	MWh		-	-	0.032328	-	-
16	Summer Transmission	-	MWh		-	-	0.017954	-	-
17	Winter Capacity	-	MWh		-	-	0.028498	-	-
18	Winter Transmission	-	MWh		-	-	0.016714	-	-
19	Critical Peak Event	-	MWh		-	-	1.000000	-	-
20	Power Factor Adjustment					97		92	(6)
21	Annual PSCR Factor	2,395,375	MWh	@	0.009410	22,540	0.009410	22,540	-
22	Total Production					$ 163,985		$ 155,867	$ (8,118)
	Transmission								
	Summer (June - Sept.)								
23	On-peak kW	1,501	MW	@	8.88	$ 13,335	9.45	$ 14,185	$ 851
	Winter (Oct. - May)								
24	On-peak kW	3,050	MW	@	8.27	25,221	8.80	26,830	1,609
25	Total Transmission					$ 38,556		$ 41,016	$ 2,460
	Delivery								
26	System Access	9,273	Bills	@	200.00	$ 1,855	200.00	$ 1,855	$ -
27	Maximum kW	5,852	MW	@	7.02	41,104	7.10	41,568	463
28	Distribution	2,395,375	MWh	@	-	-	-	-	-
29	Power Factor Adjustment					28		29	0
	Provisions								
30	Education GEI	109,193	MWh	@	(0.000194)	(21)	(0.000204)	(22)	(1)
31	Total Delivery					$ 42,966		$ 43,429	$ 463
32	Total Full Service					$ 245,507		$ 240,312	$ (5,195)
	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	7.10	18,059	201
35	Distribution	949,620	MWh	@	-	-	-	-	-
36	Power Factor Adjustment					39		40	0
	Provisions								
37	Education GEI	148,577	MWh	@	(0.000194)	(29)	(0.000204)	(30)	(1)
38	Total Delivery					$ 18,599		$ 18,800	$ 200
39	Total Full & ROA Service					$ 264,106		$ 259,112	$ (4,995)

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
Page: 14 of 23
Witness: LMConnolly
Date: June 2025

	(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								
	Summer (June - Sept.)								
	Non-capacity								
1	High-peak kWh	13,094	MWh	@	0.095630	$ 1,252	0.079138	$ 1,036	$ (216)
2	Mid-peak kWh	17,624	MWh	@	0.082506	1,454	0.070429	1,241	(213)
3	Low-peak kWh	48,268	MWh	@	0.064588	3,118	0.056930	2,748	(370)
4	Off-peak kWh	86,316	MWh	@	0.050483	4,357	0.042428	3,662	(695)
	Capacity								
5	High-peak kWh	13,094	MWh	@	0.007064	92	0.015698	206	113
6	Mid-peak kWh	17,624	MWh	@	0.006743	119	0.013977	246	127
7	Low-peak kWh	48,268	MWh	@	0.005416	261	0.011264	544	282
8	Off-peak kWh	86,316	MWh	@	0.003658	316	0.008425	727	411
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	25,824	MWh	@	0.063021	1,627	0.050956	1,316	(312)
10	Mid-peak kWh	36,161	MWh	@	0.058360	2,110	0.047242	1,708	(402)
11	Off-peak kWh	233,981	MWh	@	0.049251	11,524	0.039661	9,280	(2,244)
	Capacity								
12	High-peak kWh	25,824	MWh	@	0.004532	117	0.010113	261	144
13	Mid-peak kWh	36,161	MWh	@	0.004530	164	0.009363	339	175
14	Off-peak kWh	233,981	MWh	@	0.003899	912	0.007789	1,823	910
15	Power Factor Adjustment					44		41	(4)
	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	461,269	MWh	@	0.009410	4,341	0.009410	4,341	-
19	Total Production					$ 31,809		$ 29,518	$ (2,291)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	13,094	MWh	@	0.026667	$ 349	0.030259	$ 396	$ 47
21	Mid-peak kWh	17,624	MWh	@	0.025457	449	0.026941	475	26
22	Low-peak kWh	48,268	MWh	@	0.020445	987	0.021712	1,048	61
23	Off-peak kWh	86,316	MWh	@	0.013810	1,192	0.016239	1,402	210
24	Winter (Oct. - May)								
25	High-peak kWh	25,824	MWh	@	0.017109	442	0.019493	503	62
26	Mid-peak kWh	36,161	MWh	@	0.017102	618	0.018047	653	34
27	Off-peak kWh	233,981	MWh	@	0.014719	3,444	0.015014	3,513	69
28	Total Transmission					$ 7,481		$ 7,990	$ 509
	Delivery								
29	System Access	280	Bills	@	200.00	$ 56	200.00	$ 56	$ -
30	Maximum kW	1,306	MW	@	1.02	1,328	2.53	3,305	1,977
31	Substation Ownership	-	MW	@	(0.66)	-	(1.83)	-	-
32	Distribution	461,269	MWh	@	-	-	-	-	-
33	Power Factor Adjustment					2		5	3
	Provisions								
34	Education GEI	39,128	MWh	@	(0.000194)	(8)	(0.000204)	(8)	(0)
35	Total Delivery					$ 1,379		$ 3,359	$ 1,980
36	Total Full Service					$ 40,669		$ 40,866	$ 197

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	16,582	MWh	@	0.096778	$ 1,605	0.080064	$ 1,328	$ (277)
2	Mid-peak kWh	22,210	MWh	@	0.083496	1,854	0.071253	1,583	(272)
3	Low-peak kWh	51,542	MWh	@	0.065363	3,369	0.057596	2,969	(400)
4	Off-peak kWh	84,101	MWh	@	0.051088	4,297	0.042924	3,610	(687)
	Capacity								
5	High-peak kWh	16,582	MWh	@	0.007168	119	0.015927	264	145
6	Mid-peak kWh	22,210	MWh	@	0.006842	152	0.014181	315	163
7	Low-peak kWh	51,542	MWh	@	0.005495	283	0.011429	589	306
8	Off-peak kWh	84,101	MWh	@	0.003712	312	0.008548	719	407
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	32,473	MWh	@	0.063777	2,071	0.051553	1,674	(397)
10	Mid-peak kWh	44,028	MWh	@	0.059061	2,600	0.047795	2,104	(496)
11	Off-peak kWh	242,232	MWh	@	0.049842	12,073	0.040125	9,720	(2,354)
	Capacity								
12	High-peak kWh	32,473	MWh	@	0.004599	149	0.010261	333	184
13	Mid-peak kWh	44,028	MWh	@	0.004597	202	0.009500	418	216
14	Off-peak kWh	242,232	MWh	@	0.003956	958	0.007903	1,914	956
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	493,168	MWh	@	0.009410	4,641	0.009410	4,641	-
19	Total Production					$ 34,673		$ 32,168	$ (2,505)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	16,582	MWh	@	0.027059	$ 449	0.030700	$ 509	$ 60
21	Mid-peak kWh	22,210	MWh	@	0.025831	574	0.027334	607	33
22	Low-peak kWh	51,542	MWh	@	0.020746	1,069	0.022029	1,135	66
23	Off-peak kWh	84,101	MWh	@	0.014013	1,179	0.016477	1,386	207
	Winter (Oct. - May)								
24	High-peak kWh	32,473	MWh	@	0.017361	564	0.019778	642	78
25	Mid-peak kWh	44,028	MWh	@	0.017353	764	0.018311	806	42
26	Off-peak kWh	242,232	MWh	@	0.014935	3,618	0.015233	3,690	72
27	Total Transmission					$ 8,216		$ 8,776	$ 560
	Delivery								
28	System Access	963	Bills	@	200.00	$ 193	200.00	$ 193	$ -
29	Maximum kW	1,421	MW	@	3.50	4,969	3.84	5,448	479
30	Substation Ownership	233	MW	@	(0.83)	(194)	(1.94)	(451)	(257)
31	Distribution	493,168	MWh	@	-	-	-	-	-
32	Power Factor Adjustment					(2)		(2)	(0)
	Provisions								
33	Education GEI	18,415	MWh	@	(0.000194)	(4)	(0.000204)	(4)	(0)
34	Total Delivery					$ 4,962		$ 5,184	$ 222
35	Total Full Service					$ 47,851		$ 46,128	$ (1,723)

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	126,314	MWh	@	0.097734	$ 12,345	0.080871	$ 10,215	$ (2,130)
2	Mid-peak kWh	167,004	MWh	@	0.084321	14,082	0.071971	12,020	(2,062)
3	Low-peak kWh	372,538	MWh	@	0.066009	24,591	0.058177	21,673	(2,918)
4	Off-peak kWh	558,238	MWh	@	0.051593	28,801	0.043357	24,204	(4,598)
	Capacity								
5	High-peak kWh	126,314	MWh	@	0.007268	918	0.016180	2,044	1,126
6	Mid-peak kWh	167,004	MWh	@	0.006938	1,159	0.014406	2,406	1,247
7	Low-peak kWh	372,538	MWh	@	0.005572	2,076	0.011610	4,325	2,249
8	Off-peak kWh	558,238	MWh	@	0.003764	2,101	0.008684	4,848	2,746
	Winter (Oct. - May)								
	Non-capacity								
9	High-peak kWh	214,549	MWh	@	0.064408	13,819	0.052072	11,172	(2,647)
10	Mid-peak kWh	293,482	MWh	@	0.059644	17,505	0.048277	14,168	(3,336)
11	Off-peak kWh	1,556,945	MWh	@	0.050334	78,368	0.040530	63,103	(15,265)
	Capacity								
12	High-peak kWh	214,549	MWh	@	0.004663	1,000	0.010423	2,236	1,236
13	Mid-peak kWh	293,482	MWh	@	0.004661	1,368	0.009650	2,832	1,464
14	Off-peak kWh	1,556,945	MWh	@	0.004011	6,246	0.008028	12,500	6,254
15	Power Factor Adjustment					480		441	(39)
	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	3,289,071	MWh	@	0.009410	30,950	0.009410	30,950	-
19	Total Production					$ 235,808		$ 219,136	$ (16,672)
	Transmission								
	Summer (June - Sept.)								
20	High-peak kWh	126,314	MWh	@	0.027438	$ 3,466	0.031187	$ 3,939	$ 474
21	Mid-peak kWh	167,004	MWh	@	0.026193	4,374	0.027768	4,637	263
22	Low-peak kWh	372,538	MWh	@	0.021036	7,837	0.022378	8,337	500
23	Off-peak kWh	558,238	MWh	@	0.014209	7,932	0.016738	9,344	1,412
	Winter (Oct. - May)								
24	High-peak kWh	214,549	MWh	@	0.017604	3,777	0.020091	4,311	534
25	Mid-peak kWh	293,482	MWh	@	0.017596	5,164	0.018601	5,459	295
26	Off-peak kWh	1,556,945	MWh	@	0.015144	23,578	0.015475	24,093	515
27	Total Transmission					$ 56,128		$ 60,120	$ 3,992
	Delivery								
28	System Access	16,957	Bills	@	200.00	$ 3,391	200.00	$ 3,391	$ -
29	Maximum kW	10,204	MW	@	7.02	71,676	7.10	72,484	808
30	Distribution	3,289,071	MWh	@	-	-	-	-	-
31	Power Factor Adjustment					168		170	2
	Provisions								
32	Education GEI	276,763	MWh	@	(0.000194)	(54)	(0.000204)	(56)	(3)
33	Total Delivery					$ 75,182		$ 75,989	$ 807
34	Total Full Service					$ 367,119		$ 355,246	$ (11,873)

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	@	0.138468	$ 29	0.123949	$ 26	$ (3)
2	High-peak kWh	7,015	MWh	@	0.092312	648	0.082633	580	(68)
3	Mid-peak kWh	7,214	MWh	@	0.079643	575	0.074106	535	(40)
4	Low-peak kWh	45,458	MWh	@	0.062347	2,834	0.058897	2,677	(157)
5	Off-peak kWh	61,205	MWh	@	0.048731	2,983	0.043127	2,640	(343)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	206	MWh	@	0.008141	2	0.018205	4	2
8	High-peak kWh	7,015	MWh	@	0.005427	38	0.012136	85	47
9	Mid-peak kWh	7,214	MWh	@	0.005305	38	0.010806	78	40
10	Low-peak kWh	45,458	MWh	@	0.004363	198	0.008708	396	198
11	Off-peak kWh	61,205	MWh	@	0.002792	171	0.006513	399	228
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	647	MWh	@	0.091252	59	0.077395	50	(9)
13	High-peak kWh	14,105	MWh	@	0.060834	858	0.051596	728	(130)
14	Mid-peak kWh	14,704	MWh	@	0.056336	828	0.048308	710	(118)
15	Off-peak kWh	182,038	MWh	@	0.047542	8,654	0.040622	7,395	(1,260)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	647	MWh	@	0.005270	3	0.011728	8	4
18	High-peak kWh	14,105	MWh	@	0.003513	50	0.007818	110	61
19	Mid-peak kWh	14,704	MWh	@	0.003466	51	0.007239	106	55
20	Off-peak kWh	182,038	MWh	@	0.003037	553	0.006022	1,096	543
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		$ 17,944	$ (945)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	206	MWh	@	0.034940	$ 7	0.041731	$ 9	$ 1
26	High-peak kWh	7,015	MWh	@	0.023293	163	0.027821	195	32
27	Mid-peak kWh	7,214	MWh	@	0.022769	164	0.024770	179	14
28	Low-peak kWh	45,458	MWh	@	0.018726	851	0.019963	907	56
29	Off-peak kWh	61,205	MWh	@	0.011984	733	0.014931	914	180
	Winter (Oct. - May)								
30	Critical-peak kWh	647	MWh	@	0.022619	15	0.026884	17	3
31	High-peak kWh	14,105	MWh	@	0.015079	213	0.017922	253	40
32	Mid-peak kWh	14,704	MWh	@	0.014877	219	0.016593	244	25
33	Off-peak kWh	182,038	MWh	@	0.013037	2,373	0.013804	2,513	140
34	Total Transmission					$ 4,739		$ 5,231	$ 492
	Delivery								
35	System Access	64	Bills	@	200.00	$ 13	200.00	$ 13	$ -
36	Maximum kW	771	MW	@	1.02	785	2.53	1,953	1,168
37	Substation Ownership	-	MW	@	(0.66)	-	(1.83)	-	-
38	Power Factor Adjustment					0		1	0
39	Distribution	332,592	MWh	@	-	-	-	-	-
40	Total Delivery					$ 798		$ 1,966	$ 1,168
41	Total Full Service					$ 24,426		$ 25,141	$ 715

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	@	0.140130	$ 4	0.125399	$ 3	$ (0)
2	High-peak kWh	895	MWh	@	0.093420	84	0.083599	75	(9)
3	Mid-peak kWh	937	MWh	@	0.080599	76	0.074973	70	(5)
4	Low-peak kWh	7,371	MWh	@	0.063095	465	0.059586	439	(26)
5	Off-peak kWh	10,461	MWh	@	0.049316	516	0.043632	456	(59)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	27	MWh	@	0.008261	0	0.018470	0	0
8	High-peak kWh	895	MWh	@	0.005507	5	0.012314	11	6
9	Mid-peak kWh	937	MWh	@	0.005383	5	0.010963	10	5
10	Low-peak kWh	7,371	MWh	@	0.004427	33	0.008836	65	32
11	Off-peak kWh	10,461	MWh	@	0.002833	30	0.006609	69	39
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	79	MWh	@	0.092347	7	0.078300	6	(1)
13	High-peak kWh	1,503	MWh	@	0.061565	93	0.052200	78	(14)
14	Mid-peak kWh	1,737	MWh	@	0.057012	99	0.048873	85	(14)
15	Off-peak kWh	30,227	MWh	@	0.048112	1,454	0.041097	1,242	(212)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	79	MWh	@	0.005348	0	0.011899	1	1
18	High-peak kWh	1,503	MWh	@	0.003565	5	0.007933	12	7
19	Mid-peak kWh	1,737	MWh	@	0.003517	6	0.007344	13	7
20	Off-peak kWh	30,227	MWh	@	0.003082	93	0.006110	185	92
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		$ 2,859	$ (151)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	27	MWh	@	0.035454	$ 1	0.042340	$ 1	$ 0
26	High-peak kWh	895	MWh	@	0.023636	21	0.028227	25	4
27	Mid-peak kWh	937	MWh	@	0.023103	22	0.025132	24	2
28	Low-peak kWh	7,371	MWh	@	0.019002	140	0.020254	149	9
29	Off-peak kWh	10,461	MWh	@	0.012160	127	0.015149	158	31
	Winter (Oct. - May)								
30	Critical-peak kWh	79	MWh	@	0.022952	2	0.027276	2	0
31	High-peak kWh	1,503	MWh	@	0.015301	23	0.018184	27	4
32	Mid-peak kWh	1,737	MWh	@	0.015095	26	0.016836	29	3
33	Off-peak kWh	30,227	MWh	@	0.013228	400	0.014006	423	23
34	Total Transmission					$ 762		$ 840	$ 78
	Delivery								
35	System Access	82	Bills	@	200.00	$ 16	200.00	$ 16	$ -
36	Maximum kW	373	MW	@	3.50	1,304	3.84	1,430	126
37	Substation Ownership	169	MW	@	(0.83)	(141)	(1.94)	(327)	(186)
38	Power Factor Adjustment					(6)		(5)	0
39	Distribution	53,237	MWh	@	-	-	-	-	-
40	Total Delivery					$ 1,174		$ 1,114	$ (60)
41	Total Full Service					$ 4,945		$ 4,812	$ (133)

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-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
Page: 19 of 23
Witness: LMConnolly
Date: June 2025

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	0.126663	$ 0	$ (0)
2	High-peak kWh	66	MWh	@	0.094343	6	0.084442	6	(1)
3	Mid-peak kWh	104	MWh	@	0.081395	8	0.075729	8	(1)
4	Low-peak kWh	1,569	MWh	@	0.063719	100	0.060187	94	(6)
5	Off-peak kWh	908	MWh	@	0.049803	45	0.044072	40	(5)
	Capacity								
6	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
7	Critical-peak kWh	1	MWh	@	0.008376	0	0.018764	0	0
8	High-peak kWh	66	MWh	@	0.005584	0	0.012509	1	0
9	Mid-peak kWh	104	MWh	@	0.005458	1	0.011137	1	1
10	Low-peak kWh	1,569	MWh	@	0.004489	7	0.008976	14	7
11	Off-peak kWh	908	MWh	@	0.002873	3	0.006713	6	3
	Winter (Oct. - May)								
	Non-capacity								
12	Critical-peak kWh	4	MWh	@	0.093259	0	0.079090	0	(0)
13	High-peak kWh	93	MWh	@	0.062173	6	0.052726	5	(1)
14	Mid-peak kWh	119	MWh	@	0.057575	7	0.049366	6	(1)
15	Off-peak kWh	3,871	MWh	@	0.048588	188	0.041512	161	(27)
	Capacity								
16	Emergency kWh	-	MWh	@	1.000000	-	1.000000	-	-
17	Critical-peak kWh	4	MWh	@	0.005422	0	0.012088	0	0
18	High-peak kWh	93	MWh	@	0.003615	0	0.008058	1	0
19	Mid-peak kWh	119	MWh	@	0.003566	0	0.007461	1	0
20	Off-peak kWh	3,871	MWh	@	0.003125	12	0.006207	24	12
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		$ 373	$ (17)
	Transmission								
	Summer (June - Sept.)								
25	Critical-peak kWh	1	MWh	@	0.035950	$ 0	0.043012	$ 0	$ 0
26	High-peak kWh	66	MWh	@	0.023967	2	0.028675	2	0
27	Mid-peak kWh	104	MWh	@	0.023427	2	0.025531	3	0
28	Low-peak kWh	1,569	MWh	@	0.019268	30	0.020575	32	2
29	Off-peak kWh	908	MWh	@	0.012330	11	0.015389	14	3
	Winter (Oct. - May)								
30	Critical-peak kWh	4	MWh	@	0.023273	0	0.027709	0	0
31	High-peak kWh	93	MWh	@	0.015515	1	0.018473	2	0
32	Mid-peak kWh	119	MWh	@	0.015307	2	0.017103	2	0
33	Off-peak kWh	3,871	MWh	@	0.013413	52	0.014228	55	3
34	Total Transmission					$ 101		$ 110	$ 9
	Delivery								
35	System Access	54	Bills	@	200.00	$ 11	200.00	$ 11	$ -
36	Maximum kW	40	MW	@	7.02	280	7.10	283	3
37	Power Factor Adjustment					(1)		(1)	(0)
38	Distribution	6,737	MWh	@	-	-	-	-	-
39	Total Delivery					$ 290		$ 294	$ 3
40	Total Full Service					$ 782		$ 777	$ (5)

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Metered Lighting (GML)

Case No.: U-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	10,329	MWh	@	0.040925	$ 423	0.035201	$ 364	$ (59)
2	Primary All kWh	448	MWh	@	0.020084	9	0.017275	8	(1)
3	Annual PSCR Factor	10,777	MWh	@	0.009410	101	0.009410	101	-
4	Total Production					$ 533		$ 473	$ (60)
	Transmission								
5	Secondary All kWh	10,329	MWh	@	0.010058	104	0.010602	110	6
6	Primary All kWh	448	MWh	@	0.004936	2	0.005203	2	0
7	Total Transmission	10,777				106		112	6
	Delivery								
	Secondary								
8	System Access	4,489	Bills	@	10.00	$ 45	10.00	$ 45	$ -
9	Distribution	10,329	MWh	@	0.087373	902	0.124589	1,287	384
	Primary								
10	System Access	297	Bills	@	20.00	$ 6	20.00	$ 6	$ -
11	Distribution	448	MWh	@	0.066586	30	0.094947	43	13
12	Total Delivery					$ 983		$ 1,380	$ 397
13	Total Full Service					$ 1,622		$ 1,965	$ 342

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Universal Unmetered Light (UUL)

Case No.: U-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	-	@	0.33	6.67	0.33	9.67	$ 0	0.29	7.47	0.29	10.47	$ 0	$ 0
2	25 - 34 Watts	-	64,500	Lights	30	-	666	@	0.49	7.19	0.49	10.19	689	0.43	8.26	0.43	11.26	754	65
3	35 - 44 Watts	1,524	412,356	Lights	40	21	5,701	@	0.66	7.71	0.66	10.71	4,701	0.58	9.06	0.58	12.06	5,227	526
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	9.86	0.72	12.86	11,771	1,318
5	55 - 64 Watts	1,092	7,056	Lights	60	23	147	@	1.00	8.75	1.00	11.75	101	0.87	10.66	0.87	13.66	115	15
6	65 - 74 Watts	312	129,516	Lights	70	8	3,150	@	1.16	9.27	1.16	12.27	1,743	1.02	11.46	1.02	14.46	2,009	266
7	75 - 84 Watts	72	34,020	Lights	80	2	947	@	1.33	9.79	1.33	12.79	481	1.16	12.25	1.16	15.25	559	78
8	85 - 94 Watts	-	98,178	Lights	90	-	3,075	@	1.50	10.31	1.50	13.31	1,454	1.31	13.05	1.31	16.05	1,704	250
9	95 - 104 Watts	-	180	Lights	100	-	6	@	1.66	10.83	1.66	13.83	3	1.46	13.85	1.46	16.85	3	1
10	105 - 114 Watts	-	7,044	Lights	110	-	270	@	1.83	11.35	1.83	14.35	114	1.60	14.65	1.60	17.65	136	22
11	115 - 124 Watts	804	364,751	Lights	120	34	15,256	@	2.00	11.87	2.00	14.87	6,164	1.75	15.45	1.75	18.45	7,382	1,217
12	125 - 134 Watts	-	320	Lights	130	-	15	@	2.17	12.38	2.17	15.38	6	1.90	16.24	1.90	19.24	7	1
13	135 - 144 Watts	-	924	Lights	140	-	45	@	2.33	12.90	2.33	15.90	17	2.04	17.04	2.04	20.04	20	4
14	145 - 154 Watts	-	3,996	Lights	150	-	209	@	2.50	13.42	2.50	16.42	76	2.19	17.84	2.19	20.84	92	16
15	155 - 164 Watts	-	52	Lights	160	-	3	@	2.67	13.94	2.67	16.94	1	2.34	18.64	2.34	21.64	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	2.48	19.44	2.48	22.44	1,306	243
17	175 - 184 Watts	-	-	Lights	180	-	-	@	3.00	14.98	3.00	17.98	-	2.63	20.23	2.63	23.23	-	-
18	185 - 194 Watts	-	156	Lights	190	-	10	@	3.17	15.50	3.17	18.50	3	2.78	21.03	2.78	24.03	4	1
19	195 - 204 Watts	-	60	Lights	200	-	4	@	3.34	16.02	3.34	19.02	1	2.92	21.83	2.92	24.83	2	0
20	205 - 214 Watts	504	12,740	Lights	210	37	934	@	3.50	16.54	3.50	19.54	304	3.07	22.63	3.07	25.63	379	75
21	215 - 224 Watts	-	28	Lights	220	-	2	@	3.67	17.06	3.67	20.06	1	3.21	23.43	3.21	26.43	1	0
22	225 - 234 Watts	-	-	Lights	230	-	-	@	3.84	17.58	3.84	20.58	-	3.36	24.22	3.36	27.22	-	-
23	235 - 244 Watts	-	-	Lights	240	-	-	@	4.01	18.10	4.01	21.10	-	3.51	25.02	3.51	28.02	-	-
24	245 - 254 Watts	60	432	Lights	250	5	38	@	4.17	18.62	4.17	21.62	13	3.65	25.82	3.65	28.82	16	3
25	255 - 264 Watts	-	-	Lights	260	-	-	@	4.34	19.13	4.34	22.13	-	3.80	26.62	3.80	29.62	-	-
26	265 - 274 Watts	-	-	Lights	270	-	-	@	4.51	19.65	4.51	22.65	-	3.95	27.42	3.95	30.42	-	-
27	275 - 284 Watts	396	3,949	Lights	280	39	386	@	4.67	20.17	4.67	23.17	120	4.09	28.22	4.09	31.22	152	32
28	285 - 294 Watts	12	1,292	Lights	290	1	131	@	4.84	20.69	4.84	23.69	37	4.24	29.01	4.24	32.01	47	10
29	295 - 304 Watts	-	-	Lights	300	-	-	@	5.01	21.21	5.01	24.21	-	4.39	29.81	4.39	32.81	-	-
30	305 - 314 Watts	108	-	Lights	310	12	-	@	5.18	21.73	5.18	24.73	3	4.53	30.61	4.53	33.61	4	1
31	315 - 324 Watts	540	29,081	Lights	320	60	3,252	@	5.34	22.25	5.34	25.25	904	4.68	31.41	4.68	34.41	1,156	252
32	325 - 334 Watts	-	-	Lights	330	-	-	@	5.51	22.77	5.51	25.77	-	4.83	32.21	4.83	35.21	-	-
33	335 - 344 Watts	-	-	Lights	340	-	-	@	5.68	23.29	5.68	26.29	-	4.97	33.00	4.97	36.00	-	-
34	345 - 354 Watts	-	-	Lights	350	-	-	@	5.84	23.81	5.84	26.81	-	5.12	33.80	5.12	36.80	-	-
35	355 - 364 Watts	-	-	Lights	360	-	-	@	6.01	24.33	6.01	27.33	-	5.26	34.60	5.26	37.60	-	-
36	365 - 374 Watts	-	-	Lights	370	-	-	@	6.18	24.85	6.18	27.85	-	5.41	35.40	5.41	38.40	-	-
37	375 - 384 Watts	-	-	Lights	380	-	-	@	6.35	25.37	6.35	28.37	-	5.56	36.20	5.56	39.20	-	-
38	385 - 394 Watts	-	-	Lights	390	-	-	@	6.51	25.89	6.51	28.89	-	5.70	36.99	5.70	39.99	-	-
39	395 - 404 Watts	-	12	Lights	400	-	2	@	6.68	26.40	6.68	29.40	0	5.85	37.79	5.85	40.79	1	0
40	405 - 414 Watts	24	24	Lights	410	3	3	@	6.85	26.92	6.85	29.92	2	6.00	38.59	6.00	41.59	2	1
41	415 - 424 Watts	-	-	Lights	420	-	-	@	7.02	27.44	7.02	30.44	-	6.14	39.39	6.14	42.39	-	-
42	425 - 434 Watts	-	-	Lights	430	-	-	@	7.18	27.96	7.18	30.96	-	6.29	40.19	6.29	43.19	-	-
43	435 - 444 Watts	-	-	Lights	440	-	-	@	7.35	28.48	7.35	31.48	-	6.44	40.98	6.44	43.98	-	-
44	445 - 454 Watts	-	-	Lights	450	-	-	@	7.52	29.00	7.52	32.00	-	6.58	41.78	6.58	44.78	-	-
45	455 - 464 Watts	888	1,460	Lights	460	143	235	@	7.68	29.52	7.68	32.52	92	6.73	42.58	6.73	45.58	120	28
46	465 - 474 Watts	-	-	Lights	470	-	-	@	7.85	30.04	7.85	33.04	-	6.88	43.38	6.88	46.38	-	-
47	475 - 484 Watts	180	9,489	Lights	480	30	1,593	@	8.02	30.56	8.02	33.56	402	7.02	44.18	7.02	47.18	524	122
48	Conversion Credit	-	129,840	Lights								(6.91)	(897)				(7.91)	(1,027)	(130)
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					$ 32,981	$ 4,418

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Unmetered Service (GU)

Case No.: U-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	Non-capacity All kWh	97,806	MWh	@	0.054054	$ 5,287	0.047033	$ 4,600	$ (687)
2	Capacity All kWh	97,806	MWh	@	0.003187	312	0.007201	704	393
3	Annual PSCR Factor	97,806	MWh	@	0.009410	920	0.009410	920	-
4	Total Production					$ 6,519		$ 6,225	$ (294)
	Transmission								
5	All kWh	97,806	MWh	@	0.013872	1,357	0.015152	1,482	125
	Delivery								
6	System Access	5,578	Bills	@	2.00	$ 11	2.00	$ 11	$ -
7	Distribution	97,806	MWh	@	0.028437	2,781	0.036673	3,587	805
8	Total Delivery					$ 2,792		$ 3,598	$ 805
9	Total Full Service					$ 10,668		$ 11,305	$ 636

Schedule F-3.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail

Large Self-generation (GSG-2)

Case No.: U-21870
Exhibit No.: A-16 (LMC-3)
Schedule: F-3.0
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Witness: LMConnolly
Date: June 2025

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	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	@	0.071423	5,524	0.071423	5,524	-
	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					280		280	-
8	Total Production					$ 14,766		$ 14,766	$ -
	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	2.53	2,252	1,347
16	Interconnect	355	MW	@	(1.02)	(361)	(2.53)	(899)	(538)
17	Substation Ownership	-	MW	@	(0.66)	-	(1.83)	-	-
	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	3.84	2,339	206
21	Substation Ownership	288	MW	@	(0.83)	(239)	(1.94)	(557)	(318)
	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	7.10	438	5
25	Power Factor Adjustment					58		67	10
26	Total Delivery					$ 2,946		$ 3,658	$ 712
27	Total Standby Service					$ 18,902		$ 19,614	$ 712

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	8.96	9.10	0.14	1.6%	181.9	8.84	8.94	0.11	1.2%	178.9
2	50	17.56	18.96	1.39	7.9%	37.9	16.39	17.45	1.06	6.4%	34.9
3	100	27.13	29.91	2.79	10.3%	29.9	24.78	26.89	2.11	8.5%	26.9
4	150	36.69	40.87	4.18	11.4%	27.2	33.17	36.34	3.17	9.5%	24.2
5	200	46.25	51.82	5.57	12.0%	25.9	41.56	45.78	4.22	10.2%	22.9
6	250	55.81	62.78	6.96	12.5%	25.1	49.95	55.23	5.28	10.6%	22.1
7	300	65.38	73.73	8.36	12.8%	24.6	58.34	64.68	6.33	10.9%	21.6
8	350	74.94	84.69	9.75	13.0%	24.2	66.73	74.12	7.39	11.1%	21.2
9	400	84.50	95.64	11.14	13.2%	23.9	75.12	83.57	8.45	11.2%	20.9
10	450	94.06	106.60	12.54	13.3%	23.7	83.51	93.01	9.50	11.4%	20.7
11	500	103.63	117.56	13.93	13.4%	23.5	91.90	102.46	10.56	11.5%	20.5
12	550	113.19	128.51	15.32	13.5%	23.4	100.29	111.91	11.61	11.6%	20.3
13	600	122.75	139.47	16.71	13.6%	23.2	108.68	121.35	12.67	11.7%	20.2
14	650	132.31	150.42	18.11	13.7%	23.1	117.07	130.80	13.72	11.7%	20.1
15	700	141.88	161.38	19.50	13.7%	23.1	125.46	140.24	14.78	11.8%	20.0
16	750	151.44	172.33	20.89	13.8%	23.0	133.85	149.69	15.83	11.8%	20.0
17	800	161.00	183.29	22.29	13.8%	22.9	142.24	159.13	16.89	11.9%	19.9
18	850	170.57	194.24	23.68	13.9%	22.9	150.63	168.58	17.95	11.9%	19.8
19	900	180.13	205.20	25.07	13.9%	22.8	159.03	178.03	19.00	11.9%	19.8
20	950	189.69	216.15	26.46	14.0%	22.8	167.42	187.47	20.06	12.0%	19.7
21	1,000	199.25	227.11	27.86	14.0%	22.7	175.81	196.92	21.11	12.0%	19.7
22	1,500	294.88	336.67	41.79	14.2%	22.4	259.71	291.38	31.67	12.2%	19.4
23	2,000	390.51	446.22	55.71	14.3%	22.3	343.61	385.84	42.23	12.3%	19.3
24	2,500	486.13	555.78	69.64	14.3%	22.2	427.51	480.30	52.78	12.3%	19.2
25	3,000	581.76	665.33	83.57	14.4%	22.2	511.42	574.76	63.34	12.4%	19.2
26	3,500	677.39	774.89	97.50	14.4%	22.1	595.32	669.21	73.89	12.4%	19.1
27	4,000	773.01	884.44	111.43	14.4%	22.1	679.22	763.67	84.45	12.4%	19.1
28	4,500	868.64	994.00	125.36	14.4%	22.1	763.13	858.13	95.01	12.4%	19.1
29	5,000	964.27	1,103.55	139.29	14.4%	22.1	847.03	952.59	105.56	12.5%	19.1

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	4.96	5.10	0.14	2.8%	101.9	4.84	4.94	0.11	2.2%	98.9
2	50	13.56	14.96	1.39	10.3%	29.9	12.39	13.45	1.06	8.5%	26.9
3	100	23.13	25.91	2.79	12.0%	25.9	20.78	22.89	2.11	10.2%	22.9
4	150	32.69	36.87	4.18	12.8%	24.6	29.17	32.34	3.17	10.9%	21.6
5	200	42.25	47.82	5.57	13.2%	23.9	37.56	41.78	4.22	11.2%	20.9
6	250	51.81	58.78	6.96	13.4%	23.5	45.95	51.23	5.28	11.5%	20.5
7	300	61.38	69.73	8.36	13.6%	23.2	54.34	60.68	6.33	11.7%	20.2
8	350	70.94	80.69	9.75	13.7%	23.1	62.73	70.12	7.39	11.8%	20.0
9	400	80.50	91.64	11.14	13.8%	22.9	71.12	79.57	8.45	11.9%	19.9
10	450	90.06	102.60	12.54	13.9%	22.8	79.51	89.01	9.50	11.9%	19.8
11	500	99.63	113.56	13.93	14.0%	22.7	87.90	98.46	10.56	12.0%	19.7
12	550	109.19	124.51	15.32	14.0%	22.6	96.29	107.91	11.61	12.1%	19.6
13	600	118.75	135.47	16.71	14.1%	22.6	104.68	117.35	12.67	12.1%	19.6
14	650	128.31	146.42	18.11	14.1%	22.5	113.07	126.80	13.72	12.1%	19.5
15	700	137.88	157.38	19.50	14.1%	22.5	121.46	136.24	14.78	12.2%	19.5
16	750	147.44	168.33	20.89	14.2%	22.4	129.85	145.69	15.83	12.2%	19.4
17	800	157.00	179.29	22.29	14.2%	22.4	138.24	155.13	16.89	12.2%	19.4
18	850	166.57	190.24	23.68	14.2%	22.4	146.63	164.58	17.95	12.2%	19.4
19	900	176.13	201.20	25.07	14.2%	22.4	155.03	174.03	19.00	12.3%	19.3
20	950	185.69	212.15	26.46	14.3%	22.3	163.42	183.47	20.06	12.3%	19.3
21	1,000	195.25	223.11	27.86	14.3%	22.3	171.81	192.92	21.11	12.3%	19.3
22	1,500	290.88	332.67	41.79	14.4%	22.2	255.71	287.38	31.67	12.4%	19.2
23	2,000	386.51	442.22	55.71	14.4%	22.1	339.61	381.84	42.23	12.4%	19.1
24	2,500	482.13	551.78	69.64	14.4%	22.1	423.51	476.30	52.78	12.5%	19.1
25	3,000	577.76	661.33	83.57	14.5%	22.0	507.42	570.76	63.34	12.5%	19.0
26	3,500	673.39	770.89	97.50	14.5%	22.0	591.32	665.21	73.89	12.5%	19.0
27	4,000	769.01	880.44	111.43	14.5%	22.0	675.22	759.67	84.45	12.5%	19.0
28	4,500	864.64	990.00	125.36	14.5%	22.0	759.13	854.13	95.01	12.5%	19.0
29	5,000	960.27	1,099.55	139.29	14.5%	22.0	843.03	948.59	105.56	12.5%	19.0

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0

Witness: LMConnolly
Date: June 2025

	(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	0.96	1.10	0.14	14.6%	21.9	0.84	0.94	0.11	12.6%	18.9
2	50	9.56	10.96	1.39	14.6%	21.9	8.39	9.45	1.06	12.6%	18.9
3	100	19.13	21.91	2.79	14.6%	21.9	16.78	18.89	2.11	12.6%	18.9
4	150	28.69	32.87	4.18	14.6%	21.9	25.17	28.34	3.17	12.6%	18.9
5	200	38.25	43.82	5.57	14.6%	21.9	33.56	37.78	4.22	12.6%	18.9
6	250	47.81	54.78	6.96	14.6%	21.9	41.95	47.23	5.28	12.6%	18.9
7	300	57.38	65.73	8.36	14.6%	21.9	50.34	56.68	6.33	12.6%	18.9
8	350	66.94	76.69	9.75	14.6%	21.9	58.73	66.12	7.39	12.6%	18.9
9	400	76.50	87.64	11.14	14.6%	21.9	67.12	75.57	8.45	12.6%	18.9
10	450	86.06	98.60	12.54	14.6%	21.9	75.51	85.01	9.50	12.6%	18.9
11	500	95.63	109.56	13.93	14.6%	21.9	83.90	94.46	10.56	12.6%	18.9
12	550	105.19	120.51	15.32	14.6%	21.9	92.29	103.91	11.61	12.6%	18.9
13	600	114.75	131.47	16.71	14.6%	21.9	100.68	113.35	12.67	12.6%	18.9
14	650	124.31	142.42	18.11	14.6%	21.9	109.07	122.80	13.72	12.6%	18.9
15	700	133.88	153.38	19.50	14.6%	21.9	117.46	132.24	14.78	12.6%	18.9
16	750	143.44	164.33	20.89	14.6%	21.9	125.85	141.69	15.83	12.6%	18.9
17	800	153.00	175.29	22.29	14.6%	21.9	134.24	151.13	16.89	12.6%	18.9
18	850	162.57	186.24	23.68	14.6%	21.9	142.63	160.58	17.95	12.6%	18.9
19	900	172.13	197.20	25.07	14.6%	21.9	151.03	170.03	19.00	12.6%	18.9
20	950	181.69	208.15	26.46	14.6%	21.9	159.42	179.47	20.06	12.6%	18.9
21	1,000	191.25	219.11	27.86	14.6%	21.9	167.81	188.92	21.11	12.6%	18.9
22	1,500	286.88	328.67	41.79	14.6%	21.9	251.71	283.38	31.67	12.6%	18.9
23	2,000	382.51	438.22	55.71	14.6%	21.9	335.61	377.84	42.23	12.6%	18.9
24	2,500	478.13	547.78	69.64	14.6%	21.9	419.51	472.30	52.78	12.6%	18.9
25	3,000	573.76	657.33	83.57	14.6%	21.9	503.42	566.76	63.34	12.6%	18.9
26	3,500	669.39	766.89	97.50	14.6%	21.9	587.32	661.21	73.89	12.6%	18.9
27	4,000	765.01	876.44	111.43	14.6%	21.9	671.22	755.67	84.45	12.6%	18.9
28	4,500	860.64	986.00	125.36	14.6%	21.9	755.13	850.13	95.01	12.6%	18.9
29	5,000	956.27	1,095.55	139.29	14.6%	21.9	839.03	944.59	105.56	12.6%	18.9

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 4 of 46
Witness: LMConnolly
Date: June 2025

	(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	8.96	9.09	0.14	1.6%	181.9	8.84	8.94	0.11	1.2%	178.9
2	50	17.56	18.95	1.39	7.9%	37.9	16.37	17.43	1.07	6.5%	34.9
3	100	27.11	29.90	2.79	10.3%	29.9	24.73	26.87	2.14	8.6%	26.9
4	150	36.67	40.85	4.18	11.4%	27.2	33.10	36.30	3.20	9.7%	24.2
5	200	46.22	51.79	5.57	12.1%	25.9	41.47	45.74	4.27	10.3%	22.9
6	250	55.78	62.74	6.97	12.5%	25.1	49.83	55.17	5.34	10.7%	22.1
7	300	65.33	73.69	8.36	12.8%	24.6	58.20	64.61	6.41	11.0%	21.5
8	350	74.89	84.64	9.75	13.0%	24.2	66.57	74.04	7.48	11.2%	21.2
9	400	84.44	95.59	11.15	13.2%	23.9	74.93	83.48	8.54	11.4%	20.9
10	450	94.00	106.54	12.54	13.3%	23.7	83.30	92.91	9.61	11.5%	20.6
11	500	103.55	117.49	13.93	13.5%	23.5	91.67	102.35	10.68	11.7%	20.5
12	550	113.11	128.44	15.33	13.5%	23.4	100.03	111.78	11.75	11.7%	20.3
13	600	122.67	139.38	16.72	13.6%	23.2	108.40	121.22	12.82	11.8%	20.2
14	650	132.22	150.33	18.11	13.7%	23.1	116.77	130.65	13.88	11.9%	20.1
15	700	141.78	161.28	19.51	13.8%	23.0	125.14	140.09	14.95	11.9%	20.0
16	750	151.33	172.23	20.90	13.8%	23.0	133.50	149.52	16.02	12.0%	19.9
17	800	160.89	183.18	22.29	13.9%	22.9	141.87	158.96	17.09	12.0%	19.9
18	850	170.44	194.13	23.69	13.9%	22.8	150.24	168.39	18.16	12.1%	19.8
19	900	180.00	205.08	25.08	13.9%	22.8	158.60	177.83	19.22	12.1%	19.8
20	950	189.55	216.03	26.47	14.0%	22.7	166.97	187.26	20.29	12.2%	19.7
21	1,000	199.11	226.97	27.86	14.0%	22.7	175.34	196.69	21.36	12.2%	19.7
22	1,500	294.66	336.46	41.80	14.2%	22.4	259.00	291.04	32.04	12.4%	19.4
23	2,000	390.22	445.95	55.73	14.3%	22.3	342.67	385.39	42.72	12.5%	19.3
24	2,500	485.77	555.44	69.66	14.3%	22.2	426.34	479.74	53.40	12.5%	19.2
25	3,000	581.33	664.92	83.59	14.4%	22.2	510.01	574.08	64.08	12.6%	19.1
26	3,500	676.88	774.41	97.53	14.4%	22.1	593.68	668.43	74.76	12.6%	19.1
27	4,000	772.44	883.90	111.46	14.4%	22.1	677.34	762.78	85.44	12.6%	19.1
28	4,500	867.99	993.39	125.39	14.4%	22.1	761.01	857.13	96.12	12.6%	19.0
29	5,000	963.55	1,102.87	139.32	14.5%	22.1	844.68	951.47	106.80	12.6%	19.0

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 5 of 46
Witness: LMConnolly
Date: June 2025

	(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	4.96	5.09	0.14	2.8%	101.9	4.84	4.94	0.11	2.2%	98.9
2	50	13.56	14.95	1.39	10.3%	29.9	12.37	13.43	1.07	8.6%	26.9
3	100	23.11	25.90	2.79	12.1%	25.9	20.73	22.87	2.14	10.3%	22.9
4	150	32.67	36.85	4.18	12.8%	24.6	29.10	32.30	3.20	11.0%	21.5
5	200	42.22	47.79	5.57	13.2%	23.9	37.47	41.74	4.27	11.4%	20.9
6	250	51.78	58.74	6.97	13.5%	23.5	45.83	51.17	5.34	11.7%	20.5
7	300	61.33	69.69	8.36	13.6%	23.2	54.20	60.61	6.41	11.8%	20.2
8	350	70.89	80.64	9.75	13.8%	23.0	62.57	70.04	7.48	11.9%	20.0
9	400	80.44	91.59	11.15	13.9%	22.9	70.93	79.48	8.54	12.0%	19.9
10	450	90.00	102.54	12.54	13.9%	22.8	79.30	88.91	9.61	12.1%	19.8
11	500	99.55	113.49	13.93	14.0%	22.7	87.67	98.35	10.68	12.2%	19.7
12	550	109.11	124.44	15.33	14.0%	22.6	96.03	107.78	11.75	12.2%	19.6
13	600	118.67	135.38	16.72	14.1%	22.6	104.40	117.22	12.82	12.3%	19.5
14	650	128.22	146.33	18.11	14.1%	22.5	112.77	126.65	13.88	12.3%	19.5
15	700	137.78	157.28	19.51	14.2%	22.5	121.14	136.09	14.95	12.3%	19.4
16	750	147.33	168.23	20.90	14.2%	22.4	129.50	145.52	16.02	12.4%	19.4
17	800	156.89	179.18	22.29	14.2%	22.4	137.87	154.96	17.09	12.4%	19.4
18	850	166.44	190.13	23.69	14.2%	22.4	146.24	164.39	18.16	12.4%	19.3
19	900	176.00	201.08	25.08	14.2%	22.3	154.60	173.83	19.22	12.4%	19.3
20	950	185.55	212.03	26.47	14.3%	22.3	162.97	183.26	20.29	12.5%	19.3
21	1,000	195.11	222.97	27.86	14.3%	22.3	171.34	192.69	21.36	12.5%	19.3
22	1,500	290.66	332.46	41.80	14.4%	22.2	255.00	287.04	32.04	12.6%	19.1
23	2,000	386.22	441.95	55.73	14.4%	22.1	338.67	381.39	42.72	12.6%	19.1
24	2,500	481.77	551.44	69.66	14.5%	22.1	422.34	475.74	53.40	12.6%	19.0
25	3,000	577.33	660.92	83.59	14.5%	22.0	506.01	570.08	64.08	12.7%	19.0
26	3,500	672.88	770.41	97.53	14.5%	22.0	589.68	664.43	74.76	12.7%	19.0
27	4,000	768.44	879.90	111.46	14.5%	22.0	673.34	758.78	85.44	12.7%	19.0
28	4,500	863.99	989.39	125.39	14.5%	22.0	757.01	853.13	96.12	12.7%	19.0
29	5,000	959.55	1,098.87	139.32	14.5%	22.0	840.68	947.47	106.80	12.7%	18.9

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 6 of 46
Witness: LMConnolly
Date: June 2025

	(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	0.96	1.09	0.14	14.6%	21.9	0.84	0.94	0.11	12.8%	18.9
2	50	9.56	10.95	1.39	14.6%	21.9	8.37	9.43	1.07	12.8%	18.9
3	100	19.11	21.90	2.79	14.6%	21.9	16.73	18.87	2.14	12.8%	18.9
4	150	28.67	32.85	4.18	14.6%	21.9	25.10	28.30	3.20	12.8%	18.9
5	200	38.22	43.79	5.57	14.6%	21.9	33.47	37.74	4.27	12.8%	18.9
6	250	47.78	54.74	6.97	14.6%	21.9	41.83	47.17	5.34	12.8%	18.9
7	300	57.33	65.69	8.36	14.6%	21.9	50.20	56.61	6.41	12.8%	18.9
8	350	66.89	76.64	9.75	14.6%	21.9	58.57	66.04	7.48	12.8%	18.9
9	400	76.44	87.59	11.15	14.6%	21.9	66.93	75.48	8.54	12.8%	18.9
10	450	86.00	98.54	12.54	14.6%	21.9	75.30	84.91	9.61	12.8%	18.9
11	500	95.55	109.49	13.93	14.6%	21.9	83.67	94.35	10.68	12.8%	18.9
12	550	105.11	120.44	15.33	14.6%	21.9	92.03	103.78	11.75	12.8%	18.9
13	600	114.67	131.38	16.72	14.6%	21.9	100.40	113.22	12.82	12.8%	18.9
14	650	124.22	142.33	18.11	14.6%	21.9	108.77	122.65	13.88	12.8%	18.9
15	700	133.78	153.28	19.51	14.6%	21.9	117.14	132.09	14.95	12.8%	18.9
16	750	143.33	164.23	20.90	14.6%	21.9	125.50	141.52	16.02	12.8%	18.9
17	800	152.89	175.18	22.29	14.6%	21.9	133.87	150.96	17.09	12.8%	18.9
18	850	162.44	186.13	23.69	14.6%	21.9	142.24	160.39	18.16	12.8%	18.9
19	900	172.00	197.08	25.08	14.6%	21.9	150.60	169.83	19.22	12.8%	18.9
20	950	181.55	208.03	26.47	14.6%	21.9	158.97	179.26	20.29	12.8%	18.9
21	1,000	191.11	218.97	27.86	14.6%	21.9	167.34	188.69	21.36	12.8%	18.9
22	1,500	286.66	328.46	41.80	14.6%	21.9	251.00	283.04	32.04	12.8%	18.9
23	2,000	382.22	437.95	55.73	14.6%	21.9	334.67	377.39	42.72	12.8%	18.9
24	2,500	477.77	547.44	69.66	14.6%	21.9	418.34	471.74	53.40	12.8%	18.9
25	3,000	573.33	656.92	83.59	14.6%	21.9	502.01	566.08	64.08	12.8%	18.9
26	3,500	668.88	766.41	97.53	14.6%	21.9	585.68	660.43	74.76	12.8%	18.9
27	4,000	764.44	875.90	111.46	14.6%	21.9	669.34	754.78	85.44	12.8%	18.9
28	4,500	859.99	985.39	125.39	14.6%	21.9	753.01	849.13	96.12	12.8%	18.9
29	5,000	955.55	1,094.87	139.32	14.6%	21.9	836.68	943.47	106.80	12.8%	18.9

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 7 of 46
Witness: LMConnolly
Date: June 2025

	(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	8.93	9.09	0.16	1.8%	181.8	8.83	8.94	0.12	1.3%	178.9
2	50	17.31	18.88	1.57	9.1%	37.8	16.26	17.43	1.17	7.2%	34.9
3	100	26.61	29.76	3.14	11.8%	29.8	24.52	26.86	2.34	9.5%	26.9
4	150	35.92	40.64	4.72	13.1%	27.1	32.79	36.29	3.50	10.7%	24.2
5	200	45.23	51.51	6.29	13.9%	25.8	41.05	45.72	4.67	11.4%	22.9
6	250	54.53	62.39	7.86	14.4%	25.0	49.31	55.15	5.84	11.8%	22.1
7	300	63.84	73.27	9.43	14.8%	24.4	57.57	64.58	7.01	12.2%	21.5
8	350	73.15	84.15	11.00	15.0%	24.0	65.83	74.01	8.17	12.4%	21.1
9	400	82.45	95.03	12.57	15.2%	23.8	74.10	83.44	9.34	12.6%	20.9
10	450	91.76	105.91	14.15	15.4%	23.5	82.36	92.87	10.51	12.8%	20.6
11	500	101.07	116.79	15.72	15.6%	23.4	90.62	102.30	11.68	12.9%	20.5
12	550	110.38	127.66	17.29	15.7%	23.2	98.88	111.73	12.85	13.0%	20.3
13	600	119.68	138.54	18.86	15.8%	23.1	107.14	121.16	14.01	13.1%	20.2
14	650	128.99	149.42	20.43	15.8%	23.0	115.41	130.59	15.18	13.2%	20.1
15	700	138.30	160.30	22.00	15.9%	22.9	123.67	140.02	16.35	13.2%	20.0
16	750	147.60	171.18	23.58	16.0%	22.8	131.93	149.45	17.52	13.3%	19.9
17	800	156.91	182.06	25.15	16.0%	22.8	140.19	158.88	18.68	13.3%	19.9
18	850	166.22	192.94	26.72	16.1%	22.7	148.45	168.31	19.85	13.4%	19.8
19	900	175.52	203.81	28.29	16.1%	22.6	156.72	177.74	21.02	13.4%	19.7
20	950	184.83	214.69	29.86	16.2%	22.6	164.98	187.17	22.19	13.4%	19.7
21	1,000	194.14	225.57	31.43	16.2%	22.6	173.24	196.60	23.36	13.5%	19.7
22	1,500	287.20	334.36	47.15	16.4%	22.3	255.86	290.89	35.03	13.7%	19.4
23	2,000	380.27	443.14	62.87	16.5%	22.2	338.48	385.19	46.71	13.8%	19.3
24	2,500	473.34	551.93	78.59	16.6%	22.1	421.10	479.49	58.39	13.9%	19.2
25	3,000	566.41	660.71	94.30	16.6%	22.0	503.72	573.79	70.07	13.9%	19.1
26	3,500	659.48	769.50	110.02	16.7%	22.0	586.34	668.08	81.75	13.9%	19.1
27	4,000	752.55	878.28	125.74	16.7%	22.0	668.96	762.38	93.42	14.0%	19.1
28	4,500	845.61	987.07	141.45	16.7%	21.9	751.58	856.68	105.10	14.0%	19.0
29	5,000	938.68	1,095.85	157.17	16.7%	21.9	834.20	950.98	116.78	14.0%	19.0

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 8 of 46
Witness: LMConnolly
Date: June 2025

	(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	4.93	5.08	0.15	3.0%	101.5	4.83	4.94	0.12	2.4%	98.9
2	50	13.31	14.76	1.46	10.9%	29.5	12.26	13.43	1.17	9.5%	26.9
3	100	22.61	25.52	2.91	12.9%	25.5	20.52	22.86	2.34	11.4%	22.9
4	150	31.92	36.29	4.37	13.7%	24.2	28.79	32.29	3.50	12.2%	21.5
5	200	41.23	47.05	5.82	14.1%	23.5	37.05	41.72	4.67	12.6%	20.9
6	250	50.53	57.81	7.28	14.4%	23.1	45.31	51.15	5.84	12.9%	20.5
7	300	59.84	68.57	8.73	14.6%	22.9	53.57	60.58	7.01	13.1%	20.2
8	350	69.15	79.34	10.19	14.7%	22.7	61.83	70.01	8.17	13.2%	20.0
9	400	78.45	90.10	11.64	14.8%	22.5	70.10	79.44	9.34	13.3%	19.9
10	450	87.76	100.86	13.10	14.9%	22.4	78.36	88.87	10.51	13.4%	19.7
11	500	97.07	111.62	14.55	15.0%	22.3	86.62	98.30	11.68	13.5%	19.7
12	550	106.38	122.38	16.01	15.0%	22.3	94.88	107.73	12.85	13.5%	19.6
13	600	115.68	133.15	17.46	15.1%	22.2	103.14	117.16	14.01	13.6%	19.5
14	650	124.99	143.91	18.92	15.1%	22.1	111.41	126.59	15.18	13.6%	19.5
15	700	134.30	154.67	20.38	15.2%	22.1	119.67	136.02	16.35	13.7%	19.4
16	750	143.60	165.43	21.83	15.2%	22.1	127.93	145.45	17.52	13.7%	19.4
17	800	152.91	176.20	23.29	15.2%	22.0	136.19	154.88	18.68	13.7%	19.4
18	850	162.22	186.96	24.74	15.3%	22.0	144.45	164.31	19.85	13.7%	19.3
19	900	171.52	197.72	26.20	15.3%	22.0	152.72	173.74	21.02	13.8%	19.3
20	950	180.83	208.48	27.65	15.3%	21.9	160.98	183.17	22.19	13.8%	19.3
21	1,000	190.14	219.24	29.11	15.3%	21.9	169.24	192.60	23.36	13.8%	19.3
22	1,500	283.20	326.87	43.66	15.4%	21.8	251.86	286.89	35.03	13.9%	19.1
23	2,000	376.27	434.49	58.22	15.5%	21.7	334.48	381.19	46.71	14.0%	19.1
24	2,500	469.34	542.11	72.77	15.5%	21.7	417.10	475.49	58.39	14.0%	19.0
25	3,000	562.41	649.73	87.32	15.5%	21.7	499.72	569.79	70.07	14.0%	19.0
26	3,500	655.48	757.35	101.88	15.5%	21.6	582.34	664.08	81.75	14.0%	19.0
27	4,000	748.55	864.98	116.43	15.6%	21.6	664.96	758.38	93.42	14.0%	19.0
28	4,500	841.61	972.60	130.98	15.6%	21.6	747.58	852.68	105.10	14.1%	18.9
29	5,000	934.68	1,080.22	145.54	15.6%	21.6	830.20	946.98	116.78	14.1%	18.9

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 9 of 46
Witness: LMConnolly
Date: June 2025

	(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	0.93	1.09	0.16	16.9%	21.8	0.83	0.94	0.12	14.1%	18.9
2	50	9.31	10.88	1.57	16.9%	21.8	8.26	9.43	1.17	14.1%	18.9
3	100	18.61	21.76	3.14	16.9%	21.8	16.52	18.86	2.34	14.1%	18.9
4	150	27.92	32.64	4.72	16.9%	21.8	24.79	28.29	3.50	14.1%	18.9
5	200	37.23	43.51	6.29	16.9%	21.8	33.05	37.72	4.67	14.1%	18.9
6	250	46.53	54.39	7.86	16.9%	21.8	41.31	47.15	5.84	14.1%	18.9
7	300	55.84	65.27	9.43	16.9%	21.8	49.57	56.58	7.01	14.1%	18.9
8	350	65.15	76.15	11.00	16.9%	21.8	57.83	66.01	8.17	14.1%	18.9
9	400	74.45	87.03	12.57	16.9%	21.8	66.10	75.44	9.34	14.1%	18.9
10	450	83.76	97.91	14.15	16.9%	21.8	74.36	84.87	10.51	14.1%	18.9
11	500	93.07	108.79	15.72	16.9%	21.8	82.62	94.30	11.68	14.1%	18.9
12	550	102.38	119.66	17.29	16.9%	21.8	90.88	103.73	12.85	14.1%	18.9
13	600	111.68	130.54	18.86	16.9%	21.8	99.14	113.16	14.01	14.1%	18.9
14	650	120.99	141.42	20.43	16.9%	21.8	107.41	122.59	15.18	14.1%	18.9
15	700	130.30	152.30	22.00	16.9%	21.8	115.67	132.02	16.35	14.1%	18.9
16	750	139.60	163.18	23.58	16.9%	21.8	123.93	141.45	17.52	14.1%	18.9
17	800	148.91	174.06	25.15	16.9%	21.8	132.19	150.88	18.68	14.1%	18.9
18	850	158.22	184.94	26.72	16.9%	21.8	140.45	160.31	19.85	14.1%	18.9
19	900	167.52	195.81	28.29	16.9%	21.8	148.72	169.74	21.02	14.1%	18.9
20	950	176.83	206.69	29.86	16.9%	21.8	156.98	179.17	22.19	14.1%	18.9
21	1,000	186.14	217.57	31.43	16.9%	21.8	165.24	188.60	23.36	14.1%	18.9
22	1,500	279.20	326.36	47.15	16.9%	21.8	247.86	282.89	35.03	14.1%	18.9
23	2,000	372.27	435.14	62.87	16.9%	21.8	330.48	377.19	46.71	14.1%	18.9
24	2,500	465.34	543.93	78.59	16.9%	21.8	413.10	471.49	58.39	14.1%	18.9
25	3,000	558.41	652.71	94.30	16.9%	21.8	495.72	565.79	70.07	14.1%	18.9
26	3,500	651.48	761.50	110.02	16.9%	21.8	578.34	660.08	81.75	14.1%	18.9
27	4,000	744.55	870.28	125.74	16.9%	21.8	660.96	754.38	93.42	14.1%	18.9
28	4,500	837.61	979.07	141.45	16.9%	21.8	743.58	848.68	105.10	14.1%	18.9
29	5,000	930.68	1,087.85	157.17	16.9%	21.8	826.20	942.98	116.78	14.1%	18.9

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 10 of 46
Witness: LMConnolly
Date: June 2025

	(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	8.84	8.92	0.08	0.9%	178.4	8.84	8.92	0.08	0.9%	178.4
2	50	16.39	17.22	0.83	5.0%	34.4	16.39	17.22	0.83	5.0%	34.4
3	100	24.78	26.43	1.65	6.7%	26.4	24.78	26.43	1.65	6.7%	26.4
4	150	33.17	35.65	2.48	7.5%	23.8	33.17	35.65	2.48	7.5%	23.8
5	200	41.56	44.87	3.31	8.0%	22.4	41.56	44.87	3.31	8.0%	22.4
6	250	49.95	54.09	4.13	8.3%	21.6	49.95	54.09	4.13	8.3%	21.6
7	300	58.34	63.30	4.96	8.5%	21.1	58.34	63.30	4.96	8.5%	21.1
8	350	66.73	72.52	5.79	8.7%	20.7	66.73	72.52	5.79	8.7%	20.7
9	400	75.12	81.74	6.61	8.8%	20.4	75.12	81.74	6.61	8.8%	20.4
10	450	83.51	90.95	7.44	8.9%	20.2	83.51	90.95	7.44	8.9%	20.2
11	500	91.90	100.17	8.27	9.0%	20.0	91.90	100.17	8.27	9.0%	20.0
12	550	100.29	109.39	9.09	9.1%	19.9	100.29	109.39	9.09	9.1%	19.9
13	600	108.68	118.60	9.92	9.1%	19.8	108.68	118.60	9.92	9.1%	19.8
14	650	120.34	131.31	10.97	9.1%	20.2	117.07	127.82	10.75	9.2%	19.7
15	700	132.00	144.01	12.02	9.1%	20.6	125.46	137.04	11.57	9.2%	19.6
16	750	143.65	156.72	13.07	9.1%	20.9	133.85	146.26	12.40	9.3%	19.5
17	800	155.31	169.43	14.12	9.1%	21.2	142.24	155.47	13.23	9.3%	19.4
18	850	166.96	182.13	15.17	9.1%	21.4	150.63	164.69	14.05	9.3%	19.4
19	900	178.62	194.84	16.22	9.1%	21.6	159.03	173.91	14.88	9.4%	19.3
20	950	190.27	207.54	17.27	9.1%	21.8	167.42	183.12	15.71	9.4%	19.3
21	1,000	201.93	220.25	18.32	9.1%	22.0	175.81	192.34	16.53	9.4%	19.2
22	1,500	318.49	347.30	28.81	9.0%	23.2	259.71	284.51	24.80	9.6%	19.0
23	2,000	435.05	474.35	39.30	9.0%	23.7	343.61	376.68	33.07	9.6%	18.8
24	2,500	551.61	601.40	49.80	9.0%	24.1	427.51	468.85	41.34	9.7%	18.8
25	3,000	668.16	728.45	60.29	9.0%	24.3	511.42	561.02	49.60	9.7%	18.7
26	3,500	784.72	855.50	70.78	9.0%	24.4	595.32	653.19	57.87	9.7%	18.7
27	4,000	901.28	982.56	81.28	9.0%	24.6	679.22	745.36	66.14	9.7%	18.6
28	4,500	1,017.84	1,109.61	91.77	9.0%	24.7	763.13	837.53	74.41	9.8%	18.6
29	5,000	1,134.40	1,236.66	102.26	9.0%	24.7	847.03	929.70	82.67	9.8%	18.6

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 11 of 46
Witness: LMConnolly
Date: June 2025

	(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	4.84	4.92	0.08	1.7%	98.4	4.84	4.92	0.08	1.7%	98.4
2	50	12.39	13.22	0.83	6.7%	26.4	12.39	13.22	0.83	6.7%	26.4
3	100	20.78	22.43	1.65	8.0%	22.4	20.78	22.43	1.65	8.0%	22.4
4	150	29.17	31.65	2.48	8.5%	21.1	29.17	31.65	2.48	8.5%	21.1
5	200	37.56	40.87	3.31	8.8%	20.4	37.56	40.87	3.31	8.8%	20.4
6	250	45.95	50.09	4.13	9.0%	20.0	45.95	50.09	4.13	9.0%	20.0
7	300	54.34	59.30	4.96	9.1%	19.8	54.34	59.30	4.96	9.1%	19.8
8	350	62.73	68.52	5.79	9.2%	19.6	62.73	68.52	5.79	9.2%	19.6
9	400	71.12	77.74	6.61	9.3%	19.4	71.12	77.74	6.61	9.3%	19.4
10	450	79.51	86.95	7.44	9.4%	19.3	79.51	86.95	7.44	9.4%	19.3
11	500	87.90	96.17	8.27	9.4%	19.2	87.90	96.17	8.27	9.4%	19.2
12	550	96.29	105.39	9.09	9.4%	19.2	96.29	105.39	9.09	9.4%	19.2
13	600	104.68	114.60	9.92	9.5%	19.1	104.68	114.60	9.92	9.5%	19.1
14	650	116.34	127.31	10.97	9.4%	19.6	113.07	123.82	10.75	9.5%	19.0
15	700	128.00	140.01	12.02	9.4%	20.0	121.46	133.04	11.57	9.5%	19.0
16	750	139.65	152.72	13.07	9.4%	20.4	129.85	142.26	12.40	9.6%	19.0
17	800	151.31	165.43	14.12	9.3%	20.7	138.24	151.47	13.23	9.6%	18.9
18	850	162.96	178.13	15.17	9.3%	21.0	146.63	160.69	14.05	9.6%	18.9
19	900	174.62	190.84	16.22	9.3%	21.2	155.03	169.91	14.88	9.6%	18.9
20	950	186.27	203.54	17.27	9.3%	21.4	163.42	179.12	15.71	9.6%	18.9
21	1,000	197.93	216.25	18.32	9.3%	21.6	171.81	188.34	16.53	9.6%	18.8
22	1,500	314.49	343.30	28.81	9.2%	22.9	255.71	280.51	24.80	9.7%	18.7
23	2,000	431.05	470.35	39.30	9.1%	23.5	339.61	372.68	33.07	9.7%	18.6
24	2,500	547.61	597.40	49.80	9.1%	23.9	423.51	464.85	41.34	9.8%	18.6
25	3,000	664.16	724.45	60.29	9.1%	24.1	507.42	557.02	49.60	9.8%	18.6
26	3,500	780.72	851.50	70.78	9.1%	24.3	591.32	649.19	57.87	9.8%	18.5
27	4,000	897.28	978.56	81.28	9.1%	24.5	675.22	741.36	66.14	9.8%	18.5
28	4,500	1,013.84	1,105.61	91.77	9.1%	24.6	759.13	833.53	74.41	9.8%	18.5
29	5,000	1,130.40	1,232.66	102.26	9.0%	24.7	843.03	925.70	82.67	9.8%	18.5

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 12 of 46
Witness: LMConnolly
Date: June 2025

	(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	4.84	4.92	0.08	1.7%	98.4	4.84	4.92	0.08	1.7%	98.4
2	50	12.39	13.22	0.83	6.7%	26.4	12.39	13.22	0.83	6.7%	26.4
3	100	20.78	22.43	1.65	8.0%	22.4	20.78	22.43	1.65	8.0%	22.4
4	150	29.17	31.65	2.48	8.5%	21.1	29.17	31.65	2.48	8.5%	21.1
5	200	37.56	40.87	3.31	8.8%	20.4	37.56	40.87	3.31	8.8%	20.4
6	250	45.95	50.09	4.13	9.0%	20.0	45.95	50.09	4.13	9.0%	20.0
7	300	54.34	59.30	4.96	9.1%	19.8	54.34	59.30	4.96	9.1%	19.8
8	350	62.73	68.52	5.79	9.2%	19.6	62.73	68.52	5.79	9.2%	19.6
9	400	71.12	77.74	6.61	9.3%	19.4	71.12	77.74	6.61	9.3%	19.4
10	450	79.51	86.95	7.44	9.4%	19.3	79.51	86.95	7.44	9.4%	19.3
11	500	87.90	96.17	8.27	9.4%	19.2	87.90	96.17	8.27	9.4%	19.2
12	550	96.29	105.39	9.09	9.4%	19.2	96.29	105.39	9.09	9.4%	19.2
13	600	104.68	114.60	9.92	9.5%	19.1	104.68	114.60	9.92	9.5%	19.1
14	650	116.34	127.31	10.97	9.4%	19.6	113.07	123.82	10.75	9.5%	19.0
15	700	128.00	140.01	12.02	9.4%	20.0	121.46	133.04	11.57	9.5%	19.0
16	750	139.65	152.72	13.07	9.4%	20.4	129.85	142.26	12.40	9.6%	19.0
17	800	151.31	165.43	14.12	9.3%	20.7	138.24	151.47	13.23	9.6%	18.9
18	850	162.96	178.13	15.17	9.3%	21.0	146.63	160.69	14.05	9.6%	18.9
19	900	174.62	190.84	16.22	9.3%	21.2	155.03	169.91	14.88	9.6%	18.9
20	950	186.27	203.54	17.27	9.3%	21.4	163.42	179.12	15.71	9.6%	18.9
21	1,000	197.93	216.25	18.32	9.3%	21.6	171.81	188.34	16.53	9.6%	18.8
22	1,500	314.49	343.30	28.81	9.2%	22.9	255.71	280.51	24.80	9.7%	18.7
23	2,000	431.05	470.35	39.30	9.1%	23.5	339.61	372.68	33.07	9.7%	18.6
24	2,500	547.61	597.40	49.80	9.1%	23.9	423.51	464.85	41.34	9.8%	18.6
25	3,000	664.16	724.45	60.29	9.1%	24.1	507.42	557.02	49.60	9.8%	18.6
26	3,500	780.72	851.50	70.78	9.1%	24.3	591.32	649.19	57.87	9.8%	18.5
27	4,000	897.28	978.56	81.28	9.1%	24.5	675.22	741.36	66.14	9.8%	18.5
28	4,500	1,013.84	1,105.61	91.77	9.1%	24.6	759.13	833.53	74.41	9.8%	18.5
29	5,000	1,130.40	1,232.66	102.26	9.0%	24.7	843.03	925.70	82.67	9.8%	18.5

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	62.94	66.91	3.97	6.3%	26.8	57.17	59.71	2.54	4.4%	23.9
2	500	105.88	113.82	7.94	7.5%	22.8	94.34	99.42	5.09	5.4%	19.9
3	750	148.82	160.73	11.91	8.0%	21.4	131.50	139.13	7.63	5.8%	18.6
4	1,000	191.75	207.64	15.88	8.3%	20.8	168.67	178.84	10.17	6.0%	17.9
5	1,500	277.63	301.46	23.83	8.6%	20.1	243.01	258.27	15.26	6.3%	17.2
6	2,000	363.51	395.28	31.77	8.7%	19.8	317.34	337.69	20.35	6.4%	16.9
7	2,500	449.38	489.09	39.71	8.8%	19.6	391.68	417.11	25.43	6.5%	16.7
8	3,000	535.26	582.91	47.65	8.9%	19.4	466.01	496.53	30.52	6.5%	16.6
9	3,500	621.14	676.73	55.59	9.0%	19.3	540.35	575.95	35.60	6.6%	16.5
10	4,000	707.02	770.55	63.54	9.0%	19.3	614.68	655.37	40.69	6.6%	16.4
11	4,500	792.89	864.37	71.48	9.0%	19.2	689.02	734.80	45.78	6.6%	16.3
12	5,000	878.77	958.19	79.42	9.0%	19.2	763.35	814.22	50.86	6.7%	16.3
13	6,000	1,050.52	1,145.83	95.30	9.1%	19.1	912.03	973.06	61.04	6.7%	16.2
14	7,000	1,222.28	1,333.47	111.19	9.1%	19.0	1,060.70	1,131.91	71.21	6.7%	16.2
15	8,000	1,394.03	1,521.10	127.07	9.1%	19.0	1,209.37	1,290.75	81.38	6.7%	16.1
16	9,000	1,565.78	1,708.74	142.96	9.1%	19.0	1,358.04	1,449.59	91.55	6.7%	16.1
17	10,000	1,737.54	1,896.38	158.84	9.1%	19.0	1,506.71	1,608.44	101.73	6.8%	16.1
18	15,000	2,596.31	2,834.57	238.26	9.2%	18.9	2,250.06	2,402.65	152.59	6.8%	16.0
19	20,000	3,455.08	3,772.76	317.68	9.2%	18.9	2,993.42	3,196.87	203.45	6.8%	16.0
20	25,000	4,313.85	4,710.95	397.10	9.2%	18.8	3,736.77	3,991.09	254.32	6.8%	16.0
21	30,000	5,172.62	5,649.14	476.52	9.2%	18.8	4,480.13	4,785.31	305.18	6.8%	16.0
22	35,000	6,031.38	6,587.33	555.94	9.2%	18.8	5,223.48	5,579.53	356.04	6.8%	15.9
23	40,000	6,890.15	7,525.51	635.36	9.2%	18.8	5,966.84	6,373.75	406.91	6.8%	15.9
24	45,000	7,748.92	8,463.70	714.78	9.2%	18.8	6,710.19	7,167.96	457.77	6.8%	15.9
25	50,000	8,607.69	9,401.89	794.20	9.2%	18.8	7,453.55	7,962.18	508.64	6.8%	15.9
26	55,000	9,466.46	10,340.08	873.62	9.2%	18.8	8,196.90	8,756.40	559.50	6.8%	15.9
27	60,000	10,325.23	11,278.27	953.04	9.2%	18.8	8,940.26	9,550.62	610.36	6.8%	15.9
28	65,000	11,184.00	12,216.46	1,032.46	9.2%	18.8	9,683.61	10,344.84	661.23	6.8%	15.9
29	70,000	12,042.77	13,154.65	1,111.88	9.2%	18.8	10,426.97	11,139.06	712.09	6.8%	15.9

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	62.71	66.66	3.95	6.3%	26.7	56.94	59.46	2.52	4.4%	23.8
2	500	105.42	113.31	7.90	7.5%	22.7	93.87	98.92	5.04	5.4%	19.8
3	750	148.12	159.97	11.85	8.0%	21.3	130.81	138.38	7.57	5.8%	18.5
4	1,000	190.83	206.63	15.80	8.3%	20.7	167.75	177.83	10.09	6.0%	17.8
5	1,500	276.25	299.94	23.70	8.6%	20.0	241.62	256.75	15.13	6.3%	17.1
6	2,000	361.66	393.26	31.60	8.7%	19.7	315.50	335.67	20.17	6.4%	16.8
7	2,500	447.08	486.57	39.50	8.8%	19.5	389.37	414.59	25.22	6.5%	16.6
8	3,000	532.49	579.89	47.39	8.9%	19.3	463.24	493.50	30.26	6.5%	16.5
9	3,500	617.91	673.20	55.29	8.9%	19.2	537.12	572.42	35.30	6.6%	16.4
10	4,000	703.32	766.52	63.19	9.0%	19.2	610.99	651.34	40.35	6.6%	16.3
11	4,500	788.74	859.83	71.09	9.0%	19.1	684.87	730.26	45.39	6.6%	16.2
12	5,000	874.15	953.14	78.99	9.0%	19.1	758.74	809.17	50.43	6.6%	16.2
13	6,000	1,044.99	1,139.77	94.79	9.1%	19.0	906.49	967.01	60.52	6.7%	16.1
14	7,000	1,215.82	1,326.40	110.59	9.1%	18.9	1,054.24	1,124.84	70.61	6.7%	16.1
15	8,000	1,386.65	1,513.03	126.38	9.1%	18.9	1,201.98	1,282.68	80.69	6.7%	16.0
16	9,000	1,557.48	1,699.66	142.18	9.1%	18.9	1,349.73	1,440.51	90.78	6.7%	16.0
17	10,000	1,728.31	1,886.29	157.98	9.1%	18.9	1,497.48	1,598.35	100.87	6.7%	16.0
18	15,000	2,582.46	2,819.43	236.97	9.2%	18.8	2,236.22	2,387.52	151.30	6.8%	15.9
19	20,000	3,436.62	3,752.58	315.96	9.2%	18.8	2,974.96	3,176.69	201.73	6.8%	15.9
20	25,000	4,290.77	4,685.72	394.95	9.2%	18.7	3,713.70	3,965.87	252.17	6.8%	15.9
21	30,000	5,144.93	5,618.87	473.94	9.2%	18.7	4,452.44	4,755.04	302.60	6.8%	15.9
22	35,000	5,999.08	6,552.01	552.93	9.2%	18.7	5,191.18	5,544.21	353.03	6.8%	15.8
23	40,000	6,853.23	7,485.15	631.92	9.2%	18.7	5,929.92	6,333.39	403.47	6.8%	15.8
24	45,000	7,707.39	8,418.30	710.91	9.2%	18.7	6,668.66	7,122.56	453.90	6.8%	15.8
25	50,000	8,561.54	9,351.44	789.90	9.2%	18.7	7,407.40	7,911.73	504.34	6.8%	15.8
26	55,000	9,415.70	10,284.59	868.89	9.2%	18.7	8,146.14	8,700.91	554.77	6.8%	15.8
27	60,000	10,269.85	11,217.73	947.88	9.2%	18.7	8,884.88	9,490.08	605.20	6.8%	15.8
28	65,000	11,124.00	12,150.88	1,026.87	9.2%	18.7	9,623.62	10,279.25	655.64	6.8%	15.8
29	70,000	11,978.16	13,084.02	1,105.86	9.2%	18.7	10,362.36	11,068.43	706.07	6.8%	15.8

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Secondary Demand GSD

Case No.: U-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 15 of 46
Witness: LMConnolly
Date: June 2025

	(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	109.78	115.19	5.41	4.9%	23.0	92.93	99.20	6.27	6.8%	19.8
2	1,000	189.56	200.37	10.82	5.7%	20.0	155.86	168.40	12.55	8.0%	16.8
3	1,500	269.33	285.56	16.23	6.0%	19.0	218.78	237.60	18.82	8.6%	15.8
4	2,000	349.11	370.75	21.64	6.2%	18.5	281.71	306.80	25.09	8.9%	15.3
5	2,500	428.89	455.93	27.05	6.3%	18.2	344.64	376.00	31.37	9.1%	15.0
6	3,000	508.67	541.12	32.45	6.4%	18.0	407.57	445.20	37.64	9.2%	14.8
7	3,500	588.44	626.31	37.86	6.4%	17.9	470.49	514.40	43.91	9.3%	14.7
8	4,000	668.22	711.50	43.27	6.5%	17.8	533.42	583.60	50.18	9.4%	14.6
9	4,500	748.00	796.68	48.68	6.5%	17.7	596.35	652.81	56.46	9.5%	14.5
10	5,000	827.78	881.87	54.09	6.5%	17.6	659.28	722.01	62.73	9.5%	14.4
11	6,000	987.33	1,052.24	64.91	6.6%	17.5	785.13	860.41	75.28	9.6%	14.3
12	7,000	1,146.89	1,222.62	75.73	6.6%	17.5	910.99	998.81	87.82	9.6%	14.3
13	8,000	1,306.44	1,392.99	86.55	6.6%	17.4	1,036.84	1,137.21	100.37	9.7%	14.2
14	9,000	1,466.00	1,563.37	97.36	6.6%	17.4	1,162.70	1,275.61	112.92	9.7%	14.2
15	10,000	1,625.56	1,733.74	108.18	6.7%	17.3	1,288.55	1,414.01	125.46	9.7%	14.1
16	11,000	1,785.11	1,904.11	119.00	6.7%	17.3	1,414.41	1,552.41	138.01	9.8%	14.1
17	12,000	1,944.67	2,074.49	129.82	6.7%	17.3	1,540.26	1,690.81	150.55	9.8%	14.1
18	13,000	2,104.22	2,244.86	140.64	6.7%	17.3	1,666.12	1,829.22	163.10	9.8%	14.1
19	14,000	2,263.78	2,415.23	151.46	6.7%	17.3	1,791.97	1,967.62	175.65	9.8%	14.1
20	15,000	2,423.33	2,585.61	162.27	6.7%	17.2	1,917.83	2,106.02	188.19	9.8%	14.0
21	16,000	2,582.89	2,755.98	173.09	6.7%	17.2	2,043.68	2,244.42	200.74	9.8%	14.0
22	17,000	2,742.45	2,926.36	183.91	6.7%	17.2	2,169.54	2,382.82	213.28	9.8%	14.0
23	18,000	2,902.00	3,096.73	194.73	6.7%	17.2	2,295.39	2,521.22	225.83	9.8%	14.0
24	19,000	3,061.56	3,267.10	205.55	6.7%	17.2	2,421.25	2,659.62	238.38	9.8%	14.0
25	20,000	3,221.11	3,437.48	216.37	6.7%	17.2	2,547.10	2,798.02	250.92	9.9%	14.0
26	21,000	3,380.67	3,607.85	227.18	6.7%	17.2	2,672.96	2,936.42	263.47	9.9%	14.0
27	22,000	3,540.22	3,778.23	238.00	6.7%	17.2	2,798.81	3,074.83	276.02	9.9%	14.0
28	23,000	3,699.78	3,948.60	248.82	6.7%	17.2	2,924.67	3,213.23	288.56	9.9%	14.0
29	24,000	3,859.33	4,118.97	259.64	6.7%	17.2	3,050.52	3,351.63	301.11	9.9%	14.0

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 16 of 46
Witness: LMConnolly
Date: June 2025

	(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	109.41	114.77	5.37	4.9%	23.0	92.56	98.79	6.23	6.7%	19.8
2	1,000	188.81	199.55	10.74	5.7%	20.0	155.11	167.58	12.47	8.0%	16.8
3	1,500	268.22	284.32	16.11	6.0%	19.0	217.67	236.36	18.70	8.6%	15.8
4	2,000	347.62	369.10	21.48	6.2%	18.5	280.22	305.15	24.93	8.9%	15.3
5	2,500	427.03	453.87	26.85	6.3%	18.2	342.78	373.94	31.17	9.1%	15.0
6	3,000	506.43	538.65	32.21	6.4%	18.0	405.33	442.73	37.40	9.2%	14.8
7	3,500	585.84	623.42	37.58	6.4%	17.8	467.89	511.52	43.63	9.3%	14.6
8	4,000	665.24	708.20	42.95	6.5%	17.7	530.44	580.30	49.86	9.4%	14.5
9	4,500	744.65	792.97	48.32	6.5%	17.6	593.00	649.09	56.10	9.5%	14.4
10	5,000	824.05	877.74	53.69	6.5%	17.6	655.55	717.88	62.33	9.5%	14.4
11	6,000	982.86	1,047.29	64.43	6.6%	17.5	780.66	855.46	74.80	9.6%	14.3
12	7,000	1,141.67	1,216.84	75.17	6.6%	17.4	905.77	993.03	87.26	9.6%	14.2
13	8,000	1,300.48	1,386.39	85.91	6.6%	17.3	1,030.88	1,130.61	99.73	9.7%	14.1
14	9,000	1,459.30	1,555.94	96.64	6.6%	17.3	1,155.99	1,268.19	112.20	9.7%	14.1
15	10,000	1,618.11	1,725.49	107.38	6.6%	17.3	1,281.10	1,405.76	124.66	9.7%	14.1
16	11,000	1,776.92	1,895.04	118.12	6.6%	17.2	1,406.21	1,543.34	137.13	9.8%	14.0
17	12,000	1,935.73	2,064.59	128.86	6.7%	17.2	1,531.32	1,680.91	149.59	9.8%	14.0
18	13,000	2,094.54	2,234.14	139.60	6.7%	17.2	1,656.43	1,818.49	162.06	9.8%	14.0
19	14,000	2,253.35	2,403.68	150.34	6.7%	17.2	1,781.54	1,956.07	174.53	9.8%	14.0
20	15,000	2,412.16	2,573.23	161.07	6.7%	17.2	1,906.65	2,093.64	186.99	9.8%	14.0
21	16,000	2,570.97	2,742.78	171.81	6.7%	17.1	2,031.76	2,231.22	199.46	9.8%	13.9
22	17,000	2,729.78	2,912.33	182.55	6.7%	17.1	2,156.87	2,368.80	211.92	9.8%	13.9
23	18,000	2,888.59	3,081.88	193.29	6.7%	17.1	2,281.98	2,506.37	224.39	9.8%	13.9
24	19,000	3,047.40	3,251.43	204.03	6.7%	17.1	2,407.09	2,643.95	236.86	9.8%	13.9
25	20,000	3,206.21	3,420.98	214.77	6.7%	17.1	2,532.20	2,781.52	249.32	9.8%	13.9
26	21,000	3,365.02	3,590.53	225.50	6.7%	17.1	2,657.31	2,919.10	261.79	9.9%	13.9
27	22,000	3,523.83	3,760.08	236.24	6.7%	17.1	2,782.42	3,056.68	274.26	9.9%	13.9
28	23,000	3,682.64	3,929.63	246.98	6.7%	17.1	2,907.53	3,194.25	286.72	9.9%	13.9
29	24,000	3,841.45	4,099.17	257.72	6.7%	17.1	3,032.64	3,331.83	299.19	9.9%	13.9

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 17 of 46
Witness: LMConnolly
Date: June 2025

	(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	114.58	123.29	8.71	7.6%	24.7	93.44	98.82	5.38	5.8%	19.8
2	1,000	209.15	226.58	17.43	8.3%	22.7	166.89	177.64	10.75	6.4%	17.8
3	1,500	303.73	329.87	26.14	8.6%	22.0	240.33	256.46	16.13	6.7%	17.1
4	2,000	398.30	433.16	34.85	8.8%	21.7	313.77	335.28	21.51	6.9%	16.8
5	2,500	492.88	536.44	43.57	8.8%	21.5	387.21	414.10	26.88	6.9%	16.6
6	3,000	587.45	639.73	52.28	8.9%	21.3	460.66	492.92	32.26	7.0%	16.4
7	3,500	682.03	743.02	61.00	8.9%	21.2	534.10	571.74	37.64	7.0%	16.3
8	4,000	776.60	846.31	69.71	9.0%	21.2	607.54	650.56	43.01	7.1%	16.3
9	4,500	871.18	949.60	78.42	9.0%	21.1	680.98	729.38	48.39	7.1%	16.2
10	5,000	965.75	1,052.89	87.14	9.0%	21.1	754.43	808.20	53.77	7.1%	16.2
11	6,000	1,154.90	1,259.47	104.56	9.1%	21.0	901.31	965.83	64.52	7.2%	16.1
12	7,000	1,344.05	1,466.05	121.99	9.1%	20.9	1,048.20	1,123.47	75.28	7.2%	16.0
13	8,000	1,533.20	1,672.62	139.42	9.1%	20.9	1,195.08	1,281.11	86.03	7.2%	16.0
14	9,000	1,722.36	1,879.20	156.85	9.1%	20.9	1,341.97	1,438.75	96.78	7.2%	16.0
15	10,000	1,911.51	2,085.78	174.27	9.1%	20.9	1,488.85	1,596.39	107.54	7.2%	16.0
16	11,000	2,100.66	2,292.36	191.70	9.1%	20.8	1,635.74	1,754.03	118.29	7.2%	15.9
17	12,000	2,289.81	2,498.93	209.13	9.1%	20.8	1,782.63	1,911.67	129.04	7.2%	15.9
18	13,000	2,478.96	2,705.51	226.55	9.1%	20.8	1,929.51	2,069.31	139.80	7.2%	15.9
19	14,000	2,668.11	2,912.09	243.98	9.1%	20.8	2,076.40	2,226.95	150.55	7.3%	15.9
20	15,000	2,857.26	3,118.67	261.41	9.1%	20.8	2,223.28	2,384.59	161.30	7.3%	15.9
21	16,000	3,046.41	3,325.25	278.84	9.2%	20.8	2,370.17	2,542.22	172.06	7.3%	15.9
22	17,000	3,235.56	3,531.82	296.26	9.2%	20.8	2,517.05	2,699.86	182.81	7.3%	15.9
23	18,000	3,424.71	3,738.40	313.69	9.2%	20.8	2,663.94	2,857.50	193.56	7.3%	15.9
24	19,000	3,613.86	3,944.98	331.12	9.2%	20.8	2,810.82	3,015.14	204.32	7.3%	15.9
25	20,000	3,803.01	4,151.56	348.55	9.2%	20.8	2,957.71	3,172.78	215.07	7.3%	15.9
26	21,000	3,992.16	4,358.14	365.97	9.2%	20.8	3,104.59	3,330.42	225.83	7.3%	15.9
27	22,000	4,181.31	4,564.71	383.40	9.2%	20.7	3,251.48	3,488.06	236.58	7.3%	15.9
28	23,000	4,370.46	4,771.29	400.83	9.2%	20.7	3,398.36	3,645.70	247.33	7.3%	15.9
29	24,000	4,559.61	4,977.87	418.25	9.2%	20.7	3,545.25	3,803.34	258.09	7.3%	15.8

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	114.11	122.78	8.67	7.6%	24.6	92.98	98.32	5.33	5.7%	19.7
2	1,000	208.23	225.57	17.34	8.3%	22.6	165.96	176.63	10.67	6.4%	17.7
3	1,500	302.34	328.35	26.01	8.6%	21.9	238.94	254.95	16.00	6.7%	17.0
4	2,000	396.46	431.14	34.68	8.7%	21.6	311.92	333.26	21.34	6.8%	16.7
5	2,500	490.57	533.92	43.35	8.8%	21.4	384.91	411.58	26.67	6.9%	16.5
6	3,000	584.68	636.71	52.02	8.9%	21.2	457.89	489.89	32.00	7.0%	16.3
7	3,500	678.80	739.49	60.69	8.9%	21.1	530.87	568.21	37.34	7.0%	16.2
8	4,000	772.91	842.28	69.37	9.0%	21.1	603.85	646.52	42.67	7.1%	16.2
9	4,500	867.02	945.06	78.04	9.0%	21.0	676.83	724.84	48.00	7.1%	16.1
10	5,000	961.14	1,047.84	86.71	9.0%	21.0	749.81	803.15	53.34	7.1%	16.1
11	6,000	1,149.37	1,253.41	104.05	9.1%	20.9	895.77	959.78	64.01	7.1%	16.0
12	7,000	1,337.59	1,458.98	121.39	9.1%	20.8	1,041.74	1,116.41	74.67	7.2%	15.9
13	8,000	1,525.82	1,664.55	138.73	9.1%	20.8	1,187.70	1,273.04	85.34	7.2%	15.9
14	9,000	1,714.05	1,870.12	156.07	9.1%	20.8	1,333.66	1,429.67	96.01	7.2%	15.9
15	10,000	1,902.28	2,075.69	173.41	9.1%	20.8	1,479.62	1,586.30	106.68	7.2%	15.9
16	11,000	2,090.50	2,281.26	190.75	9.1%	20.7	1,625.59	1,742.93	117.34	7.2%	15.8
17	12,000	2,278.73	2,486.83	208.10	9.1%	20.7	1,771.55	1,899.56	128.01	7.2%	15.8
18	13,000	2,466.96	2,692.40	225.44	9.1%	20.7	1,917.51	2,056.19	138.68	7.2%	15.8
19	14,000	2,655.19	2,897.96	242.78	9.1%	20.7	2,063.47	2,212.82	149.35	7.2%	15.8
20	15,000	2,843.41	3,103.53	260.12	9.1%	20.7	2,209.44	2,369.45	160.01	7.2%	15.8
21	16,000	3,031.64	3,309.10	277.46	9.2%	20.7	2,355.40	2,526.08	170.68	7.2%	15.8
22	17,000	3,219.87	3,514.67	294.80	9.2%	20.7	2,501.36	2,682.71	181.35	7.3%	15.8
23	18,000	3,408.10	3,720.24	312.14	9.2%	20.7	2,647.32	2,839.34	192.02	7.3%	15.8
24	19,000	3,596.32	3,925.81	329.48	9.2%	20.7	2,793.29	2,995.97	202.68	7.3%	15.8
25	20,000	3,784.55	4,131.38	346.83	9.2%	20.7	2,939.25	3,152.60	213.35	7.3%	15.8
26	21,000	3,972.78	4,336.95	364.17	9.2%	20.7	3,085.21	3,309.23	224.02	7.3%	15.8
27	22,000	4,161.01	4,542.52	381.51	9.2%	20.6	3,231.17	3,465.86	234.69	7.3%	15.8
28	23,000	4,349.24	4,748.08	398.85	9.2%	20.6	3,377.14	3,622.49	245.35	7.3%	15.7
29	24,000	4,537.46	4,953.65	416.19	9.2%	20.6	3,523.10	3,779.12	256.02	7.3%	15.7

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	103.93	112.45	8.52	8.2%	22.5	82.80	87.98	5.18	6.3%	17.6
2	1,000	187.86	204.89	17.04	9.1%	20.5	145.59	155.95	10.36	7.1%	15.6
3	1,500	271.78	297.34	25.56	9.4%	19.8	208.39	223.93	15.55	7.5%	14.9
4	2,000	355.71	389.79	34.07	9.6%	19.5	271.18	291.91	20.73	7.6%	14.6
5	2,500	439.64	482.23	42.59	9.7%	19.3	333.98	359.89	25.91	7.8%	14.4
6	3,000	523.57	574.68	51.11	9.8%	19.2	396.77	427.86	31.09	7.8%	14.3
7	3,500	607.49	667.13	59.63	9.8%	19.1	459.57	495.84	36.27	7.9%	14.2
8	4,000	691.42	759.57	68.15	9.9%	19.0	522.36	563.82	41.45	7.9%	14.1
9	4,500	775.35	852.02	76.67	9.9%	18.9	585.16	631.79	46.64	8.0%	14.0
10	5,000	859.28	944.46	85.19	9.9%	18.9	647.95	699.77	51.82	8.0%	14.0
11	6,000	1,027.13	1,129.36	102.22	10.0%	18.8	773.54	835.72	62.18	8.0%	13.9
12	7,000	1,194.99	1,314.25	119.26	10.0%	18.8	899.13	971.68	72.55	8.1%	13.9
13	8,000	1,362.84	1,499.14	136.30	10.0%	18.7	1,024.72	1,107.63	82.91	8.1%	13.8
14	9,000	1,530.70	1,684.04	153.34	10.0%	18.7	1,150.31	1,243.59	93.27	8.1%	13.8
15	10,000	1,698.56	1,868.93	170.37	10.0%	18.7	1,275.90	1,379.54	103.64	8.1%	13.8
16	11,000	1,866.41	2,053.82	187.41	10.0%	18.7	1,401.49	1,515.49	114.00	8.1%	13.8
17	12,000	2,034.27	2,238.71	204.45	10.1%	18.7	1,527.09	1,651.45	124.36	8.1%	13.8
18	13,000	2,202.12	2,423.61	221.48	10.1%	18.6	1,652.68	1,787.40	134.73	8.2%	13.7
19	14,000	2,369.98	2,608.50	238.52	10.1%	18.6	1,778.27	1,923.36	145.09	8.2%	13.7
20	15,000	2,537.83	2,793.39	255.56	10.1%	18.6	1,903.86	2,059.31	155.45	8.2%	13.7
21	16,000	2,705.69	2,978.29	272.60	10.1%	18.6	2,029.45	2,195.26	165.82	8.2%	13.7
22	17,000	2,873.55	3,163.18	289.63	10.1%	18.6	2,155.04	2,331.22	176.18	8.2%	13.7
23	18,000	3,041.40	3,348.07	306.67	10.1%	18.6	2,280.63	2,467.17	186.54	8.2%	13.7
24	19,000	3,209.26	3,532.96	323.71	10.1%	18.6	2,406.22	2,603.13	196.91	8.2%	13.7
25	20,000	3,377.11	3,717.86	340.75	10.1%	18.6	2,531.81	2,739.08	207.27	8.2%	13.7
26	21,000	3,544.97	3,902.75	357.78	10.1%	18.6	2,657.40	2,875.03	217.64	8.2%	13.7
27	22,000	3,712.82	4,087.64	374.82	10.1%	18.6	2,782.99	3,010.99	228.00	8.2%	13.7
28	23,000	3,880.68	4,272.54	391.86	10.1%	18.6	2,908.58	3,146.94	238.36	8.2%	13.7
29	24,000	4,048.53	4,457.43	408.89	10.1%	18.6	3,034.17	3,282.90	248.73	8.2%	13.7

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

Case No.: U-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 20 of 46
Witness: LMConnolly
Date: June 2025

	(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	149.00	152.91	3.90	2.6%	30.6	138.80	140.59	1.79	1.3%	28.1
2	1,000	198.00	205.81	7.81	3.9%	20.6	177.61	181.18	3.57	2.0%	18.1
3	1,500	247.00	258.72	11.71	4.7%	17.2	216.41	221.77	5.36	2.5%	14.8
4	2,000	296.00	311.62	15.62	5.3%	15.6	255.22	262.36	7.15	2.8%	13.1
5	2,500	345.00	364.53	19.52	5.7%	14.6	294.02	302.95	8.93	3.0%	12.1
6	3,000	394.00	417.43	23.43	5.9%	13.9	332.82	343.55	10.72	3.2%	11.5
7	4,000	492.01	523.25	31.24	6.3%	13.1	410.43	424.73	14.30	3.5%	10.6
8	5,000	590.01	629.06	39.05	6.6%	12.6	488.04	505.91	17.87	3.7%	10.1
9	6,000	688.01	734.87	46.86	6.8%	12.2	565.65	587.09	21.44	3.8%	9.8
10	7,000	786.01	840.68	54.67	7.0%	12.0	643.26	668.27	25.02	3.9%	9.5
11	8,000	884.01	946.49	62.48	7.1%	11.8	720.86	749.45	28.59	4.0%	9.4
12	9,000	982.01	1,052.30	70.29	7.2%	11.7	798.47	830.64	32.16	4.0%	9.2
13	10,000	1,080.02	1,158.11	78.10	7.2%	11.6	876.08	911.82	35.74	4.1%	9.1
14	15,000	1,570.02	1,687.17	117.15	7.5%	11.2	1,264.12	1,317.73	53.61	4.2%	8.8
15	20,000	2,060.03	2,216.23	156.20	7.6%	11.1	1,652.16	1,723.64	71.48	4.3%	8.6
16	25,000	2,550.04	2,745.29	195.25	7.7%	11.0	2,040.20	2,129.55	89.35	4.4%	8.5
17	30,000	3,040.05	3,274.34	234.30	7.7%	10.9	2,428.24	2,535.46	107.22	4.4%	8.5
18	35,000	3,530.05	3,803.40	273.35	7.7%	10.9	2,816.28	2,941.36	125.08	4.4%	8.4
19	40,000	4,020.06	4,332.46	312.40	7.8%	10.8	3,204.32	3,347.27	142.95	4.5%	8.4
20	45,000	4,510.07	4,861.51	351.45	7.8%	10.8	3,592.36	3,753.18	160.82	4.5%	8.3
21	50,000	5,000.08	5,390.57	390.50	7.8%	10.8	3,980.40	4,159.09	178.69	4.5%	8.3
22	60,000	5,980.09	6,448.69	468.59	7.8%	10.7	4,756.48	4,970.91	214.43	4.5%	8.3
23	70,000	6,960.11	7,506.80	546.69	7.9%	10.7	5,532.56	5,782.73	250.17	4.5%	8.3
24	80,000	7,940.12	8,564.92	624.79	7.9%	10.7	6,308.64	6,594.55	285.91	4.5%	8.2
25	90,000	8,920.14	9,623.03	702.89	7.9%	10.7	7,084.72	7,406.37	321.65	4.5%	8.2
26	100,000	9,900.15	10,681.14	780.99	7.9%	10.7	7,860.80	8,218.19	357.38	4.5%	8.2
27	110,000	10,880.17	11,739.26	859.09	7.9%	10.7	8,636.88	9,030.00	393.12	4.6%	8.2
28	120,000	11,860.18	12,797.37	937.19	7.9%	10.7	9,412.96	9,841.82	428.86	4.6%	8.2
29	130,000	12,840.20	13,855.49	1,015.29	7.9%	10.7	10,189.04	10,653.64	464.60	4.6%	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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	148.72	152.62	3.90	2.6%	30.5	138.53	140.30	1.78	1.3%	28.1
2	1,000	197.44	205.24	7.79	3.9%	20.5	177.05	180.61	3.56	2.0%	18.1
3	1,500	246.17	257.85	11.69	4.7%	17.2	215.58	220.91	5.33	2.5%	14.7
4	2,000	294.89	310.47	15.58	5.3%	15.5	254.10	261.21	7.11	2.8%	13.1
5	2,500	343.61	363.09	19.48	5.7%	14.5	292.63	301.51	8.89	3.0%	12.1
6	3,000	392.33	415.71	23.38	6.0%	13.9	331.15	341.82	10.67	3.2%	11.4
7	4,000	489.77	520.94	31.17	6.4%	13.0	408.20	422.42	14.22	3.5%	10.6
8	5,000	587.22	626.18	38.96	6.6%	12.5	485.25	503.03	17.78	3.7%	10.1
9	6,000	684.66	731.41	46.75	6.8%	12.2	562.30	583.64	21.34	3.8%	9.7
10	7,000	782.10	836.65	54.54	7.0%	12.0	639.35	664.24	24.89	3.9%	9.5
11	8,000	879.55	941.88	62.34	7.1%	11.8	716.40	744.85	28.45	4.0%	9.3
12	9,000	976.99	1,047.12	70.13	7.2%	11.6	793.45	825.45	32.00	4.0%	9.2
13	10,000	1,074.44	1,152.35	77.92	7.3%	11.5	870.50	906.06	35.56	4.1%	9.1
14	15,000	1,561.65	1,678.53	116.88	7.5%	11.2	1,255.75	1,309.09	53.34	4.2%	8.7
15	20,000	2,048.87	2,204.71	155.84	7.6%	11.0	1,641.00	1,712.12	71.12	4.3%	8.6
16	25,000	2,536.09	2,730.89	194.80	7.7%	10.9	2,026.25	2,115.15	88.90	4.4%	8.5
17	30,000	3,023.31	3,257.06	233.76	7.7%	10.9	2,411.50	2,518.18	106.68	4.4%	8.4
18	35,000	3,510.52	3,783.24	272.72	7.8%	10.8	2,796.75	2,921.20	124.45	4.4%	8.3
19	40,000	3,997.74	4,309.42	311.68	7.8%	10.8	3,182.00	3,324.23	142.23	4.5%	8.3
20	45,000	4,484.96	4,835.59	350.64	7.8%	10.7	3,567.25	3,727.26	160.01	4.5%	8.3
21	50,000	4,972.18	5,361.77	389.60	7.8%	10.7	3,952.50	4,130.29	177.79	4.5%	8.3
22	60,000	5,946.61	6,414.13	467.51	7.9%	10.7	4,723.00	4,936.35	213.35	4.5%	8.2
23	70,000	6,921.05	7,466.48	545.43	7.9%	10.7	5,493.50	5,742.41	248.91	4.5%	8.2
24	80,000	7,895.48	8,518.84	623.35	7.9%	10.6	6,264.00	6,548.47	284.47	4.5%	8.2
25	90,000	8,869.92	9,571.19	701.27	7.9%	10.6	7,034.50	7,354.53	320.03	4.5%	8.2
26	100,000	9,844.35	10,623.54	779.19	7.9%	10.6	7,805.00	8,160.59	355.58	4.6%	8.2
27	110,000	10,818.79	11,675.90	857.11	7.9%	10.6	8,575.50	8,966.64	391.14	4.6%	8.2
28	120,000	11,793.22	12,728.25	935.03	7.9%	10.6	9,346.00	9,772.70	426.70	4.6%	8.1
29	130,000	12,767.66	13,780.61	1,012.95	7.9%	10.6	10,116.50	10,578.76	462.26	4.6%	8.1

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	153.59	155.74	2.15	1.4%	31.1	143.26	143.27	0.00	0.0%	28.7
2	1,000	207.19	211.48	4.29	2.1%	21.1	186.53	186.54	0.01	0.0%	18.7
3	1,500	260.78	267.22	6.44	2.5%	17.8	229.79	229.81	0.01	0.0%	15.3
4	2,000	314.38	322.96	8.58	2.7%	16.1	273.06	273.08	0.02	0.0%	13.7
5	2,500	367.97	378.70	10.73	2.9%	15.1	316.32	316.35	0.02	0.0%	12.7
6	3,000	421.57	434.44	12.87	3.1%	14.5	359.58	359.61	0.03	0.0%	12.0
7	4,000	528.76	545.92	17.16	3.2%	13.6	446.11	446.15	0.04	0.0%	11.2
8	5,000	635.95	657.40	21.45	3.4%	13.1	532.64	532.69	0.05	0.0%	10.7
9	6,000	743.14	768.88	25.74	3.5%	12.8	619.17	619.23	0.06	0.0%	10.3
10	7,000	850.33	880.36	30.03	3.5%	12.6	705.70	705.77	0.07	0.0%	10.1
11	8,000	957.51	991.84	34.33	3.6%	12.4	792.23	792.30	0.08	0.0%	9.9
12	9,000	1,064.70	1,103.32	38.62	3.6%	12.3	878.75	878.84	0.09	0.0%	9.8
13	10,000	1,171.89	1,214.80	42.91	3.7%	12.1	965.28	965.38	0.10	0.0%	9.7
14	15,000	1,707.84	1,772.20	64.36	3.8%	11.8	1,397.92	1,398.07	0.15	0.0%	9.3
15	20,000	2,243.79	2,329.60	85.81	3.8%	11.6	1,830.57	1,830.76	0.20	0.0%	9.2
16	25,000	2,779.73	2,887.00	107.27	3.9%	11.5	2,263.21	2,263.45	0.25	0.0%	9.1
17	30,000	3,315.68	3,444.40	128.72	3.9%	11.5	2,695.85	2,696.14	0.29	0.0%	9.0
18	35,000	3,851.63	4,001.80	150.17	3.9%	11.4	3,128.49	3,128.83	0.34	0.0%	8.9
19	40,000	4,387.57	4,559.20	171.63	3.9%	11.4	3,561.13	3,561.52	0.39	0.0%	8.9
20	45,000	4,923.52	5,116.60	193.08	3.9%	11.4	3,993.77	3,994.21	0.44	0.0%	8.9
21	50,000	5,459.47	5,674.00	214.53	3.9%	11.3	4,426.41	4,426.90	0.49	0.0%	8.9
22	60,000	6,531.36	6,788.80	257.44	3.9%	11.3	5,291.70	5,292.29	0.59	0.0%	8.8
23	70,000	7,603.25	7,903.60	300.35	4.0%	11.3	6,156.98	6,157.67	0.69	0.0%	8.8
24	80,000	8,675.14	9,018.40	343.26	4.0%	11.3	7,022.26	7,023.05	0.79	0.0%	8.8
25	90,000	9,747.04	10,133.20	386.16	4.0%	11.3	7,887.54	7,888.43	0.88	0.0%	8.8
26	100,000	10,818.93	11,248.00	429.07	4.0%	11.2	8,752.83	8,753.81	0.98	0.0%	8.8
27	110,000	11,890.82	12,362.80	471.98	4.0%	11.2	9,618.11	9,619.19	1.08	0.0%	8.7
28	120,000	12,962.72	13,477.60	514.88	4.0%	11.2	10,483.39	10,484.57	1.18	0.0%	8.7
29	130,000	14,034.61	14,592.40	557.79	4.0%	11.2	11,348.67	11,349.95	1.28	0.0%	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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	153.32	155.45	2.14	1.4%	31.1	142.99	142.98	(0.00)	0.0%	28.6
2	1,000	206.63	210.90	4.27	2.1%	21.1	185.97	185.96	(0.01)	0.0%	18.6
3	1,500	259.95	266.36	6.41	2.5%	17.8	228.96	228.94	(0.01)	0.0%	15.3
4	2,000	313.26	321.81	8.55	2.7%	16.1	271.94	271.92	(0.02)	0.0%	13.6
5	2,500	366.58	377.26	10.68	2.9%	15.1	314.93	314.91	(0.02)	0.0%	12.6
6	3,000	419.89	432.71	12.82	3.1%	14.4	357.91	357.89	(0.02)	0.0%	11.9
7	4,000	526.53	543.62	17.09	3.2%	13.6	443.88	443.85	(0.03)	0.0%	11.1
8	5,000	633.16	654.52	21.36	3.4%	13.1	529.85	529.81	(0.04)	0.0%	10.6
9	6,000	739.79	765.42	25.64	3.5%	12.8	615.82	615.77	(0.05)	0.0%	10.3
10	7,000	846.42	876.33	29.91	3.5%	12.5	701.79	701.73	(0.06)	0.0%	10.0
11	8,000	953.05	987.23	34.18	3.6%	12.3	787.76	787.70	(0.07)	0.0%	9.8
12	9,000	1,059.68	1,098.14	38.45	3.6%	12.2	873.73	873.66	(0.07)	0.0%	9.7
13	10,000	1,166.31	1,209.04	42.73	3.7%	12.1	959.70	959.62	(0.08)	0.0%	9.6
14	15,000	1,699.47	1,763.56	64.09	3.8%	11.8	1,389.55	1,389.43	(0.12)	0.0%	9.3
15	20,000	2,232.63	2,318.08	85.45	3.8%	11.6	1,819.41	1,819.24	(0.16)	0.0%	9.1
16	25,000	2,765.78	2,872.60	106.82	3.9%	11.5	2,249.26	2,249.05	(0.20)	0.0%	9.0
17	30,000	3,298.94	3,427.12	128.18	3.9%	11.4	2,679.11	2,678.86	(0.25)	0.0%	8.9
18	35,000	3,832.10	3,981.64	149.54	3.9%	11.4	3,108.96	3,108.67	(0.29)	0.0%	8.9
19	40,000	4,365.25	4,536.16	170.91	3.9%	11.3	3,538.81	3,538.48	(0.33)	0.0%	8.8
20	45,000	4,898.41	5,090.68	192.27	3.9%	11.3	3,968.66	3,968.29	(0.37)	0.0%	8.8
21	50,000	5,431.57	5,645.20	213.63	3.9%	11.3	4,398.51	4,398.10	(0.41)	0.0%	8.8
22	60,000	6,497.88	6,754.24	256.36	3.9%	11.3	5,258.22	5,257.73	(0.49)	0.0%	8.8
23	70,000	7,564.19	7,863.28	299.09	4.0%	11.2	6,117.92	6,117.35	(0.57)	0.0%	8.7
24	80,000	8,630.50	8,972.32	341.82	4.0%	11.2	6,977.62	6,976.97	(0.65)	0.0%	8.7
25	90,000	9,696.82	10,081.36	384.54	4.0%	11.2	7,837.32	7,836.59	(0.74)	0.0%	8.7
26	100,000	10,763.13	11,190.40	427.27	4.0%	11.2	8,697.03	8,696.21	(0.82)	0.0%	8.7
27	110,000	11,829.44	12,299.44	470.00	4.0%	11.2	9,556.73	9,555.83	(0.90)	0.0%	8.7
28	120,000	12,895.76	13,408.48	512.72	4.0%	11.2	10,416.43	10,415.45	(0.98)	0.0%	8.7
29	130,000	13,962.07	14,517.52	555.45	4.0%	11.2	11,276.13	11,275.07	(1.06)	0.0%	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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	161.24	163.61	2.37	1.5%	32.7	150.79	150.99	0.20	0.1%	30.2
2	1,000	222.48	227.22	4.75	2.1%	22.7	201.58	201.98	0.40	0.2%	20.2
3	1,500	283.72	290.84	7.12	2.5%	19.4	252.36	252.97	0.61	0.2%	16.9
4	2,000	344.96	354.45	9.49	2.8%	17.7	303.15	303.96	0.81	0.3%	15.2
5	2,500	406.19	418.06	11.87	2.9%	16.7	353.94	354.95	1.01	0.3%	14.2
6	3,000	467.43	481.67	14.24	3.0%	16.1	404.73	405.94	1.21	0.3%	13.5
7	4,000	589.91	608.90	18.99	3.2%	15.2	506.30	507.92	1.62	0.3%	12.7
8	5,000	712.39	736.12	23.73	3.3%	14.7	607.88	609.90	2.02	0.3%	12.2
9	6,000	834.87	863.35	28.48	3.4%	14.4	709.46	711.88	2.43	0.3%	11.9
10	7,000	957.34	990.57	33.23	3.5%	14.2	811.03	813.87	2.83	0.3%	11.6
11	8,000	1,079.82	1,117.79	37.97	3.5%	14.0	912.61	915.85	3.24	0.4%	11.4
12	9,000	1,202.30	1,245.02	42.72	3.6%	13.8	1,014.19	1,017.83	3.64	0.4%	11.3
13	10,000	1,324.78	1,372.24	47.46	3.6%	13.7	1,115.76	1,119.81	4.05	0.4%	11.2
14	15,000	1,937.17	2,008.36	71.20	3.7%	13.4	1,623.64	1,629.71	6.07	0.4%	10.9
15	20,000	2,549.56	2,644.49	94.93	3.7%	13.2	2,131.52	2,139.62	8.09	0.4%	10.7
16	25,000	3,161.95	3,280.61	118.66	3.8%	13.1	2,639.40	2,649.52	10.12	0.4%	10.6
17	30,000	3,774.33	3,916.73	142.39	3.8%	13.1	3,147.29	3,159.42	12.14	0.4%	10.5
18	35,000	4,386.72	4,552.85	166.13	3.8%	13.0	3,655.17	3,669.33	14.16	0.4%	10.5
19	40,000	4,999.11	5,188.97	189.86	3.8%	13.0	4,163.05	4,179.23	16.18	0.4%	10.4
20	45,000	5,611.50	5,825.09	213.59	3.8%	12.9	4,670.93	4,689.14	18.21	0.4%	10.4
21	50,000	6,223.89	6,461.21	237.32	3.8%	12.9	5,178.81	5,199.04	20.23	0.4%	10.4
22	60,000	7,448.67	7,733.46	284.79	3.8%	12.9	6,194.57	6,218.85	24.28	0.4%	10.4
23	70,000	8,673.45	9,005.70	332.25	3.8%	12.9	7,210.33	7,238.66	28.32	0.4%	10.3
24	80,000	9,898.23	10,277.94	379.72	3.8%	12.8	8,226.09	8,258.46	32.37	0.4%	10.3
25	90,000	11,123.00	11,550.18	427.18	3.8%	12.8	9,241.86	9,278.27	36.42	0.4%	10.3
26	100,000	12,347.78	12,822.43	474.64	3.8%	12.8	10,257.62	10,298.08	40.46	0.4%	10.3
27	110,000	13,572.56	14,094.67	522.11	3.8%	12.8	11,273.38	11,317.89	44.51	0.4%	10.3
28	120,000	14,797.34	15,366.91	569.57	3.8%	12.8	12,289.14	12,337.70	48.55	0.4%	10.3
29	130,000	16,022.12	16,639.15	617.04	3.9%	12.8	13,304.90	13,357.50	52.60	0.4%	10.3

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 25 of 46
Witness: LMConnolly
Date: June 2025

	(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	160.96	163.32	2.36	1.5%	32.7	150.51	150.70	0.19	0.1%	30.1
2	1,000	221.92	226.65	4.73	2.1%	22.7	201.02	201.40	0.39	0.2%	20.1
3	1,500	282.88	289.97	7.09	2.5%	19.3	251.53	252.11	0.58	0.2%	16.8
4	2,000	343.84	353.30	9.46	2.8%	17.7	302.04	302.81	0.77	0.3%	15.1
5	2,500	404.80	416.62	11.82	2.9%	16.7	352.55	353.51	0.97	0.3%	14.1
6	3,000	465.76	479.94	14.19	3.0%	16.0	403.05	404.21	1.16	0.3%	13.5
7	4,000	587.68	606.59	18.91	3.2%	15.2	504.07	505.62	1.55	0.3%	12.6
8	5,000	709.60	733.24	23.64	3.3%	14.7	605.09	607.02	1.93	0.3%	12.1
9	6,000	831.52	859.89	28.37	3.4%	14.3	706.11	708.43	2.32	0.3%	11.8
10	7,000	953.44	986.54	33.10	3.5%	14.1	807.13	809.83	2.71	0.3%	11.6
11	8,000	1,075.36	1,113.19	37.83	3.5%	13.9	908.15	911.24	3.09	0.3%	11.4
12	9,000	1,197.28	1,239.83	42.56	3.6%	13.8	1,009.16	1,012.64	3.48	0.3%	11.3
13	10,000	1,319.20	1,366.48	47.28	3.6%	13.7	1,110.18	1,114.05	3.87	0.3%	11.1
14	15,000	1,928.80	1,999.72	70.93	3.7%	13.3	1,615.27	1,621.07	5.80	0.4%	10.8
15	20,000	2,538.40	2,632.97	94.57	3.7%	13.2	2,120.36	2,128.10	7.73	0.4%	10.6
16	25,000	3,148.00	3,266.21	118.21	3.8%	13.1	2,625.45	2,635.12	9.67	0.4%	10.5
17	30,000	3,757.59	3,899.45	141.85	3.8%	13.0	3,130.55	3,142.14	11.60	0.4%	10.5
18	35,000	4,367.19	4,532.69	165.50	3.8%	13.0	3,635.64	3,649.17	13.53	0.4%	10.4
19	40,000	4,976.79	5,165.93	189.14	3.8%	12.9	4,140.73	4,156.19	15.46	0.4%	10.4
20	45,000	5,586.39	5,799.17	212.78	3.8%	12.9	4,645.82	4,663.22	17.40	0.4%	10.4
21	50,000	6,195.99	6,432.41	236.42	3.8%	12.9	5,150.91	5,170.24	19.33	0.4%	10.3
22	60,000	7,415.19	7,698.90	283.71	3.8%	12.8	6,161.09	6,184.29	23.20	0.4%	10.3
23	70,000	8,634.39	8,965.38	330.99	3.8%	12.8	7,171.27	7,198.34	27.06	0.4%	10.3
24	80,000	9,853.59	10,231.86	378.28	3.8%	12.8	8,181.45	8,212.38	30.93	0.4%	10.3
25	90,000	11,072.78	11,498.34	425.56	3.8%	12.8	9,191.64	9,226.43	34.80	0.4%	10.3
26	100,000	12,291.98	12,764.83	472.84	3.8%	12.8	10,201.82	10,240.48	38.66	0.4%	10.2
27	110,000	13,511.18	14,031.31	520.13	3.8%	12.8	11,212.00	11,254.53	42.53	0.4%	10.2
28	120,000	14,730.38	15,297.79	567.41	3.9%	12.7	12,222.18	12,268.58	46.39	0.4%	10.2
29	130,000	15,949.58	16,564.27	614.70	3.9%	12.7	13,232.36	13,282.62	50.26	0.4%	10.2

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 1

Case No.: U-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	7.51	7.60	0.08	1.1%	7.6	6.61	6.56	(0.05)	-0.8%	6.6
2	110	8.24	8.34	0.09	1.1%	7.6	7.25	7.19	(0.05)	-0.8%	6.5
3	120	8.97	9.08	0.10	1.1%	7.6	7.89	7.83	(0.06)	-0.8%	6.5
4	130	9.71	9.82	0.11	1.1%	7.6	8.53	8.47	(0.06)	-0.8%	6.5
5	140	10.44	10.55	0.12	1.1%	7.5	9.17	9.10	(0.07)	-0.8%	6.5
6	150	11.17	11.29	0.13	1.1%	7.5	9.81	9.74	(0.07)	-0.8%	6.5
7	200	14.82	14.99	0.17	1.1%	7.5	13.02	12.92	(0.10)	-0.8%	6.5
8	250	18.48	18.69	0.21	1.1%	7.5	16.22	16.10	(0.12)	-0.8%	6.4
9	300	22.14	22.39	0.25	1.1%	7.5	19.43	19.28	(0.15)	-0.8%	6.4
10	350	25.79	26.09	0.29	1.1%	7.5	22.63	22.46	(0.17)	-0.8%	6.4
11	400	29.45	29.78	0.34	1.1%	7.4	25.83	25.64	(0.20)	-0.8%	6.4
12	450	33.11	33.48	0.38	1.1%	7.4	29.04	28.82	(0.22)	-0.8%	6.4
13	500	36.76	37.18	0.42	1.1%	7.4	32.24	31.99	(0.25)	-0.8%	6.4
14	600	44.07	44.58	0.50	1.1%	7.4	38.65	38.35	(0.30)	-0.8%	6.4
15	700	51.39	51.97	0.59	1.1%	7.4	45.06	44.71	(0.35)	-0.8%	6.4
16	800	58.70	59.37	0.67	1.1%	7.4	51.47	51.07	(0.40)	-0.8%	6.4
17	900	66.01	66.77	0.76	1.1%	7.4	57.88	57.43	(0.45)	-0.8%	6.4
18	1,000	73.32	74.16	0.84	1.1%	7.4	64.29	63.79	(0.50)	-0.8%	6.4
19	1,500	109.88	111.14	1.26	1.1%	7.4	96.33	95.58	(0.75)	-0.8%	6.4
20	2,000	146.45	148.12	1.68	1.1%	7.4	128.37	127.38	(1.00)	-0.8%	6.4
21	2,500	183.01	185.11	2.10	1.1%	7.4	160.42	159.17	(1.24)	-0.8%	6.4
22	3,000	219.57	222.09	2.52	1.1%	7.4	192.46	190.97	(1.49)	-0.8%	6.4
23	3,500	256.13	259.07	2.94	1.1%	7.4	224.51	222.76	(1.74)	-0.8%	6.4
24	4,000	292.69	296.05	3.36	1.1%	7.4	256.55	254.56	(1.99)	-0.8%	6.4
25	4,500	329.25	333.03	3.78	1.1%	7.4	288.59	286.35	(2.24)	-0.8%	6.4
26	5,000	365.82	370.01	4.20	1.1%	7.4	320.64	318.15	(2.49)	-0.8%	6.4
27	5,500	402.38	406.99	4.62	1.1%	7.4	352.68	349.94	(2.74)	-0.8%	6.4
28	6,000	438.94	443.97	5.04	1.1%	7.4	384.72	381.74	(2.99)	-0.8%	6.4
29	6,500	475.50	480.96	5.45	1.1%	7.4	416.77	413.53	(3.23)	-0.8%	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 1
Primary Interruptible Provision GI

Case No.: U-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	6.21	6.29	0.08	1.4%	6.3	5.46	5.41	(0.05)	-0.9%	5.4
2	110	6.81	6.90	0.09	1.4%	6.3	5.98	5.93	(0.05)	-0.9%	5.4
3	120	7.41	7.51	0.10	1.4%	6.3	6.51	6.45	(0.06)	-0.9%	5.4
4	130	8.01	8.12	0.11	1.4%	6.2	7.03	6.97	(0.06)	-0.9%	5.4
5	140	8.61	8.73	0.12	1.4%	6.2	7.56	7.49	(0.07)	-0.9%	5.3
6	150	9.21	9.33	0.13	1.4%	6.2	8.08	8.01	(0.07)	-0.9%	5.3
7	200	12.21	12.38	0.17	1.4%	6.2	10.71	10.61	(0.10)	-0.9%	5.3
8	250	15.21	15.42	0.21	1.4%	6.2	13.34	13.21	(0.12)	-0.9%	5.3
9	300	18.22	18.47	0.25	1.4%	6.2	15.97	15.82	(0.15)	-0.9%	5.3
10	350	21.22	21.51	0.29	1.4%	6.1	18.59	18.42	(0.17)	-0.9%	5.3
11	400	24.22	24.56	0.34	1.4%	6.1	21.22	21.02	(0.20)	-0.9%	5.3
12	450	27.22	27.60	0.38	1.4%	6.1	23.85	23.63	(0.22)	-0.9%	5.3
13	500	30.23	30.65	0.42	1.4%	6.1	26.48	26.23	(0.25)	-0.9%	5.2
14	600	36.23	36.74	0.50	1.4%	6.1	31.73	31.44	(0.30)	-0.9%	5.2
15	700	42.24	42.83	0.59	1.4%	6.1	36.99	36.64	(0.35)	-0.9%	5.2
16	800	48.24	48.92	0.67	1.4%	6.1	42.25	41.85	(0.40)	-0.9%	5.2
17	900	54.25	55.01	0.76	1.4%	6.1	47.50	47.05	(0.45)	-0.9%	5.2
18	1,000	60.26	61.09	0.84	1.4%	6.1	52.76	52.26	(0.50)	-0.9%	5.2
19	1,500	90.28	91.54	1.26	1.4%	6.1	79.04	78.29	(0.75)	-0.9%	5.2
20	2,000	120.31	121.99	1.68	1.4%	6.1	105.31	104.32	(1.00)	-0.9%	5.2
21	2,500	150.34	152.44	2.10	1.4%	6.1	131.59	130.35	(1.24)	-0.9%	5.2
22	3,000	180.37	182.88	2.52	1.4%	6.1	157.87	156.38	(1.49)	-0.9%	5.2
23	3,500	210.39	213.33	2.94	1.4%	6.1	184.15	182.41	(1.74)	-0.9%	5.2
24	4,000	240.42	243.78	3.36	1.4%	6.1	210.43	208.44	(1.99)	-0.9%	5.2
25	4,500	270.45	274.23	3.78	1.4%	6.1	236.71	234.47	(2.24)	-0.9%	5.2
26	5,000	300.48	304.67	4.20	1.4%	6.1	262.98	260.50	(2.49)	-0.9%	5.2
27	5,500	330.50	335.12	4.62	1.4%	6.1	289.26	286.53	(2.74)	-0.9%	5.2
28	6,000	360.53	365.57	5.04	1.4%	6.1	315.54	312.56	(2.99)	-0.9%	5.2
29	6,500	390.56	396.01	5.45	1.4%	6.1	341.82	338.59	(3.23)	-0.9%	5.2

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	8.96	8.86	(0.09)	-1.1%	8.9	7.90	7.67	(0.22)	-2.8%	7.7
2	110	9.83	9.73	(0.10)	-1.1%	8.8	8.67	8.42	(0.25)	-2.9%	7.7
3	120	10.71	10.60	(0.11)	-1.1%	8.8	9.44	9.17	(0.27)	-2.9%	7.6
4	130	11.58	11.46	(0.12)	-1.1%	8.8	10.21	9.92	(0.29)	-2.9%	7.6
5	140	12.46	12.33	(0.13)	-1.1%	8.8	10.98	10.66	(0.31)	-2.9%	7.6
6	150	13.34	13.19	(0.14)	-1.1%	8.8	11.75	11.41	(0.34)	-2.9%	7.6
7	200	17.71	17.53	(0.19)	-1.1%	8.8	15.60	15.15	(0.45)	-2.9%	7.6
8	250	22.09	21.86	(0.24)	-1.1%	8.7	19.45	18.88	(0.56)	-2.9%	7.6
9	300	26.47	26.19	(0.28)	-1.1%	8.7	23.29	22.62	(0.67)	-2.9%	7.5
10	350	30.85	30.52	(0.33)	-1.1%	8.7	27.14	26.36	(0.79)	-2.9%	7.5
11	400	35.23	34.85	(0.38)	-1.1%	8.7	30.99	30.09	(0.90)	-2.9%	7.5
12	450	39.61	39.18	(0.43)	-1.1%	8.7	34.84	33.83	(1.01)	-2.9%	7.5
13	500	43.99	43.51	(0.47)	-1.1%	8.7	38.69	37.57	(1.12)	-2.9%	7.5
14	600	52.74	52.18	(0.57)	-1.1%	8.7	46.39	45.04	(1.35)	-2.9%	7.5
15	700	61.50	60.84	(0.66)	-1.1%	8.7	54.09	52.51	(1.57)	-2.9%	7.5
16	800	70.26	69.50	(0.76)	-1.1%	8.7	61.79	59.99	(1.80)	-2.9%	7.5
17	900	79.01	78.16	(0.85)	-1.1%	8.7	69.48	67.46	(2.02)	-2.9%	7.5
18	1,000	87.77	86.83	(0.95)	-1.1%	8.7	77.18	74.93	(2.25)	-2.9%	7.5
19	1,500	131.56	130.14	(1.42)	-1.1%	8.7	115.67	112.30	(3.37)	-2.9%	7.5
20	2,000	175.34	173.45	(1.89)	-1.1%	8.7	154.17	149.67	(4.50)	-2.9%	7.5
21	2,500	219.13	216.76	(2.36)	-1.1%	8.7	192.66	187.03	(5.62)	-2.9%	7.5
22	3,000	262.91	260.08	(2.84)	-1.1%	8.7	231.15	224.40	(6.75)	-2.9%	7.5
23	3,500	306.70	303.39	(3.31)	-1.1%	8.7	269.64	261.77	(7.87)	-2.9%	7.5
24	4,000	350.48	346.70	(3.78)	-1.1%	8.7	308.13	299.14	(8.99)	-2.9%	7.5
25	4,500	394.27	390.01	(4.25)	-1.1%	8.7	346.62	336.50	(10.12)	-2.9%	7.5
26	5,000	438.05	433.33	(4.73)	-1.1%	8.7	385.11	373.87	(11.24)	-2.9%	7.5
27	5,500	481.84	476.64	(5.20)	-1.1%	8.7	423.60	411.24	(12.37)	-2.9%	7.5
28	6,000	525.62	519.95	(5.67)	-1.1%	8.7	462.10	448.60	(13.49)	-2.9%	7.5
29	6,500	569.41	563.26	(6.14)	-1.1%	8.7	500.59	485.97	(14.62)	-2.9%	7.5

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 29 of 46
Witness: LMConnolly
Date: June 2025

	(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	7.41	7.31	(0.09)	-1.3%	7.3	6.53	6.30	(0.22)	-3.4%	6.3
2	110	8.13	8.02	(0.10)	-1.3%	7.3	7.16	6.91	(0.25)	-3.5%	6.3
3	120	8.85	8.73	(0.11)	-1.3%	7.3	7.79	7.53	(0.27)	-3.5%	6.3
4	130	9.57	9.44	(0.12)	-1.3%	7.3	8.43	8.14	(0.29)	-3.5%	6.3
5	140	10.29	10.16	(0.13)	-1.3%	7.3	9.06	8.75	(0.31)	-3.5%	6.2
6	150	11.01	10.87	(0.14)	-1.3%	7.2	9.69	9.36	(0.34)	-3.5%	6.2
7	200	14.61	14.42	(0.19)	-1.3%	7.2	12.86	12.41	(0.45)	-3.5%	6.2
8	250	18.21	17.98	(0.24)	-1.3%	7.2	16.02	15.46	(0.56)	-3.5%	6.2
9	300	21.82	21.53	(0.28)	-1.3%	7.2	19.19	18.51	(0.67)	-3.5%	6.2
10	350	25.42	25.09	(0.33)	-1.3%	7.2	22.35	21.56	(0.79)	-3.5%	6.2
11	400	29.02	28.64	(0.38)	-1.3%	7.2	25.52	24.62	(0.90)	-3.5%	6.2
12	450	32.62	32.20	(0.43)	-1.3%	7.2	28.68	27.67	(1.01)	-3.5%	6.1
13	500	36.23	35.75	(0.47)	-1.3%	7.2	31.85	30.72	(1.12)	-3.5%	6.1
14	600	43.43	42.87	(0.57)	-1.3%	7.1	38.17	36.83	(1.35)	-3.5%	6.1
15	700	50.64	49.98	(0.66)	-1.3%	7.1	44.50	42.93	(1.57)	-3.5%	6.1
16	800	57.84	57.09	(0.76)	-1.3%	7.1	50.83	49.03	(1.80)	-3.5%	6.1
17	900	65.05	64.20	(0.85)	-1.3%	7.1	57.16	55.14	(2.02)	-3.5%	6.1
18	1,000	72.25	71.31	(0.95)	-1.3%	7.1	63.49	61.24	(2.25)	-3.5%	6.1
19	1,500	108.28	106.86	(1.42)	-1.3%	7.1	95.14	91.76	(3.37)	-3.5%	6.1
20	2,000	144.31	142.42	(1.89)	-1.3%	7.1	126.78	122.29	(4.50)	-3.5%	6.1
21	2,500	180.33	177.97	(2.36)	-1.3%	7.1	158.43	152.81	(5.62)	-3.5%	6.1
22	3,000	216.36	213.53	(2.84)	-1.3%	7.1	190.07	183.33	(6.75)	-3.5%	6.1
23	3,500	252.39	249.08	(3.31)	-1.3%	7.1	221.72	213.85	(7.87)	-3.5%	6.1
24	4,000	288.42	284.63	(3.78)	-1.3%	7.1	253.37	244.37	(8.99)	-3.6%	6.1
25	4,500	324.44	320.19	(4.25)	-1.3%	7.1	285.01	274.89	(10.12)	-3.6%	6.1
26	5,000	360.47	355.74	(4.73)	-1.3%	7.1	316.66	305.41	(11.24)	-3.6%	6.1
27	5,500	396.50	391.30	(5.20)	-1.3%	7.1	348.30	335.93	(12.37)	-3.6%	6.1
28	6,000	432.52	426.85	(5.67)	-1.3%	7.1	379.95	366.46	(13.49)	-3.6%	6.1
29	6,500	468.55	462.41	(6.14)	-1.3%	7.1	411.59	396.98	(14.62)	-3.6%	6.1

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 30 of 46
Witness: LMConnolly
Date: June 2025

	(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	9.64	9.51	(0.13)	-1.4%	9.5	8.57	8.31	(0.26)	-3.1%	8.3
2	110	10.59	10.44	(0.14)	-1.4%	9.5	9.41	9.12	(0.29)	-3.1%	8.3
3	120	11.53	11.38	(0.16)	-1.4%	9.5	10.25	9.93	(0.32)	-3.1%	8.3
4	130	12.48	12.31	(0.17)	-1.4%	9.5	11.09	10.74	(0.34)	-3.1%	8.3
5	140	13.42	13.24	(0.18)	-1.4%	9.5	11.92	11.56	(0.37)	-3.1%	8.3
6	150	14.37	14.17	(0.20)	-1.4%	9.4	12.76	12.37	(0.40)	-3.1%	8.2
7	200	19.09	18.83	(0.26)	-1.4%	9.4	16.95	16.42	(0.53)	-3.1%	8.2
8	250	23.81	23.48	(0.33)	-1.4%	9.4	21.14	20.48	(0.66)	-3.1%	8.2
9	300	28.53	28.14	(0.39)	-1.4%	9.4	25.32	24.53	(0.79)	-3.1%	8.2
10	350	33.25	32.79	(0.46)	-1.4%	9.4	29.51	28.59	(0.92)	-3.1%	8.2
11	400	37.98	37.45	(0.53)	-1.4%	9.4	33.70	32.64	(1.05)	-3.1%	8.2
12	450	42.70	42.11	(0.59)	-1.4%	9.4	37.89	36.70	(1.19)	-3.1%	8.2
13	500	47.42	46.76	(0.66)	-1.4%	9.4	42.07	40.76	(1.32)	-3.1%	8.2
14	600	56.86	56.08	(0.79)	-1.4%	9.3	50.45	48.87	(1.58)	-3.1%	8.1
15	700	66.31	65.39	(0.92)	-1.4%	9.3	58.82	56.98	(1.84)	-3.1%	8.1
16	800	75.75	74.70	(1.05)	-1.4%	9.3	67.20	65.09	(2.11)	-3.1%	8.1
17	900	85.20	84.01	(1.18)	-1.4%	9.3	75.57	73.20	(2.37)	-3.1%	8.1
18	1,000	94.64	93.33	(1.31)	-1.4%	9.3	83.95	81.31	(2.64)	-3.1%	8.1
19	1,500	141.86	139.89	(1.97)	-1.4%	9.3	125.82	121.87	(3.95)	-3.1%	8.1
20	2,000	189.08	186.45	(2.63)	-1.4%	9.3	167.69	162.42	(5.27)	-3.1%	8.1
21	2,500	236.30	233.01	(3.29)	-1.4%	9.3	209.57	202.98	(6.59)	-3.1%	8.1
22	3,000	283.52	279.58	(3.94)	-1.4%	9.3	251.44	243.53	(7.91)	-3.1%	8.1
23	3,500	330.74	326.14	(4.60)	-1.4%	9.3	293.31	284.09	(9.22)	-3.1%	8.1
24	4,000	377.96	372.70	(5.26)	-1.4%	9.3	335.18	324.64	(10.54)	-3.1%	8.1
25	4,500	425.18	419.26	(5.92)	-1.4%	9.3	377.06	365.20	(11.86)	-3.1%	8.1
26	5,000	472.40	465.83	(6.57)	-1.4%	9.3	418.93	405.75	(13.18)	-3.1%	8.1
27	5,500	519.62	512.39	(7.23)	-1.4%	9.3	460.80	446.31	(14.49)	-3.1%	8.1
28	6,000	566.84	558.95	(7.89)	-1.4%	9.3	502.68	486.87	(15.81)	-3.1%	8.1
29	6,500	614.06	605.51	(8.54)	-1.4%	9.3	544.55	527.42	(17.13)	-3.1%	8.1

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 31 of 46
Witness: LMConnolly
Date: June 2025

	(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	8.11	7.98	(0.13)	-1.6%	8.0	7.22	6.96	(0.26)	-3.7%	7.0
2	110	8.90	8.75	(0.14)	-1.6%	8.0	7.92	7.63	(0.29)	-3.7%	6.9
3	120	9.69	9.53	(0.16)	-1.6%	7.9	8.62	8.31	(0.32)	-3.7%	6.9
4	130	10.48	10.31	(0.17)	-1.6%	7.9	9.32	8.98	(0.34)	-3.7%	6.9
5	140	11.27	11.09	(0.18)	-1.6%	7.9	10.03	9.66	(0.37)	-3.7%	6.9
6	150	12.06	11.86	(0.20)	-1.6%	7.9	10.73	10.33	(0.40)	-3.7%	6.9
7	200	16.02	15.75	(0.26)	-1.6%	7.9	14.24	13.71	(0.53)	-3.7%	6.9
8	250	19.97	19.64	(0.33)	-1.6%	7.9	17.75	17.09	(0.66)	-3.7%	6.8
9	300	23.92	23.53	(0.39)	-1.6%	7.8	21.26	20.47	(0.79)	-3.7%	6.8
10	350	27.88	27.42	(0.46)	-1.7%	7.8	24.77	23.84	(0.92)	-3.7%	6.8
11	400	31.83	31.31	(0.53)	-1.7%	7.8	28.28	27.22	(1.05)	-3.7%	6.8
12	450	35.79	35.19	(0.59)	-1.7%	7.8	31.79	30.60	(1.19)	-3.7%	6.8
13	500	39.74	39.08	(0.66)	-1.7%	7.8	35.30	33.98	(1.32)	-3.7%	6.8
14	600	47.65	46.86	(0.79)	-1.7%	7.8	42.31	40.73	(1.58)	-3.7%	6.8
15	700	55.55	54.63	(0.92)	-1.7%	7.8	49.33	47.49	(1.84)	-3.7%	6.8
16	800	63.46	62.41	(1.05)	-1.7%	7.8	56.35	54.25	(2.11)	-3.7%	6.8
17	900	71.37	70.19	(1.18)	-1.7%	7.8	63.37	61.00	(2.37)	-3.7%	6.8
18	1,000	79.28	77.96	(1.31)	-1.7%	7.8	70.39	67.76	(2.64)	-3.7%	6.8
19	1,500	118.82	116.85	(1.97)	-1.7%	7.8	105.49	101.53	(3.95)	-3.7%	6.8
20	2,000	158.36	155.73	(2.63)	-1.7%	7.8	140.58	135.31	(5.27)	-3.7%	6.8
21	2,500	197.89	194.61	(3.29)	-1.7%	7.8	175.68	169.09	(6.59)	-3.7%	6.8
22	3,000	237.43	233.49	(3.94)	-1.7%	7.8	210.77	202.87	(7.91)	-3.8%	6.8
23	3,500	276.97	272.37	(4.60)	-1.7%	7.8	245.87	236.65	(9.22)	-3.8%	6.8
24	4,000	316.51	311.25	(5.26)	-1.7%	7.8	280.97	270.43	(10.54)	-3.8%	6.8
25	4,500	356.05	350.14	(5.92)	-1.7%	7.8	316.06	304.20	(11.86)	-3.8%	6.8
26	5,000	395.59	389.02	(6.57)	-1.7%	7.8	351.16	337.98	(13.18)	-3.8%	6.8
27	5,500	435.13	427.90	(7.23)	-1.7%	7.8	386.25	371.76	(14.49)	-3.8%	6.8
28	6,000	474.67	466.78	(7.89)	-1.7%	7.8	421.35	405.54	(15.81)	-3.8%	6.8
29	6,500	514.21	505.66	(8.54)	-1.7%	7.8	456.45	439.32	(17.13)	-3.8%	6.8

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	9.28	9.65	0.37	4.0%	9.7	7.78	7.71	(0.07)	-0.9%	7.7
2	110	10.19	10.60	0.40	4.0%	9.6	8.54	8.47	(0.07)	-0.9%	7.7
3	120	11.10	11.54	0.44	4.0%	9.6	9.30	9.22	(0.08)	-0.9%	7.7
4	130	12.01	12.49	0.48	4.0%	9.6	10.06	9.97	(0.09)	-0.9%	7.7
5	140	12.92	13.43	0.52	4.0%	9.6	10.81	10.72	(0.09)	-0.9%	7.7
6	150	13.82	14.38	0.55	4.0%	9.6	11.57	11.47	(0.10)	-0.9%	7.6
7	200	18.37	19.10	0.74	4.0%	9.6	15.36	15.23	(0.13)	-0.9%	7.6
8	250	22.91	23.83	0.92	4.0%	9.5	19.15	18.99	(0.17)	-0.9%	7.6
9	300	27.45	28.55	1.10	4.0%	9.5	22.94	22.74	(0.20)	-0.9%	7.6
10	350	31.99	33.28	1.29	4.0%	9.5	26.73	26.50	(0.23)	-0.9%	7.6
11	400	36.53	38.00	1.47	4.0%	9.5	30.52	30.26	(0.27)	-0.9%	7.6
12	450	41.07	42.73	1.66	4.0%	9.5	34.31	34.01	(0.30)	-0.9%	7.6
13	500	45.61	47.45	1.84	4.0%	9.5	38.11	37.77	(0.33)	-0.9%	7.6
14	600	54.70	56.90	2.21	4.0%	9.5	45.69	45.29	(0.40)	-0.9%	7.5
15	700	63.78	66.35	2.58	4.0%	9.5	53.27	52.80	(0.47)	-0.9%	7.5
16	800	72.86	75.81	2.94	4.0%	9.5	60.85	60.31	(0.53)	-0.9%	7.5
17	900	81.94	85.26	3.31	4.0%	9.5	68.43	67.83	(0.60)	-0.9%	7.5
18	1,000	91.03	94.71	3.68	4.0%	9.5	76.01	75.34	(0.67)	-0.9%	7.5
19	1,500	136.44	141.96	5.52	4.0%	9.5	113.92	112.91	(1.00)	-0.9%	7.5
20	2,000	181.85	189.21	7.36	4.0%	9.5	151.82	150.49	(1.34)	-0.9%	7.5
21	2,500	227.26	236.47	9.20	4.0%	9.5	189.73	188.06	(1.67)	-0.9%	7.5
22	3,000	272.68	283.72	11.04	4.1%	9.5	227.63	225.63	(2.00)	-0.9%	7.5
23	3,500	318.09	330.97	12.88	4.1%	9.5	265.54	263.20	(2.34)	-0.9%	7.5
24	4,000	363.50	378.23	14.72	4.1%	9.5	303.44	300.77	(2.67)	-0.9%	7.5
25	4,500	408.91	425.48	16.57	4.1%	9.5	341.35	338.34	(3.01)	-0.9%	7.5
26	5,000	454.33	472.73	18.41	4.1%	9.5	379.26	375.92	(3.34)	-0.9%	7.5
27	5,500	499.74	519.99	20.25	4.1%	9.5	417.16	413.49	(3.67)	-0.9%	7.5
28	6,000	545.15	567.24	22.09	4.1%	9.5	455.07	451.06	(4.01)	-0.9%	7.5
29	6,500	590.56	614.49	23.93	4.1%	9.5	492.97	488.63	(4.34)	-0.9%	7.5

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 33 of 46
Witness: LMConnolly
Date: June 2025

	(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	10.13	10.13	(0.01)	-0.1%	10.1	8.56	8.12	(0.44)	-5.1%	8.1
2	110	11.13	11.12	(0.01)	-0.1%	10.1	9.39	8.91	(0.48)	-5.1%	8.1
3	120	12.12	12.11	(0.01)	-0.1%	10.1	10.23	9.70	(0.53)	-5.2%	8.1
4	130	13.11	13.11	(0.01)	-0.1%	10.1	11.06	10.49	(0.57)	-5.2%	8.1
5	140	14.11	14.10	(0.01)	-0.1%	10.1	11.90	11.28	(0.61)	-5.2%	8.1
6	150	15.10	15.09	(0.01)	-0.1%	10.1	12.73	12.07	(0.66)	-5.2%	8.0
7	200	20.07	20.06	(0.01)	-0.1%	10.0	16.91	16.03	(0.88)	-5.2%	8.0
8	250	25.03	25.02	(0.01)	-0.1%	10.0	21.09	19.99	(1.10)	-5.2%	8.0
9	300	30.00	29.98	(0.02)	-0.1%	10.0	25.27	23.95	(1.32)	-5.2%	8.0
10	350	34.97	34.95	(0.02)	-0.1%	10.0	29.44	27.91	(1.54)	-5.2%	8.0
11	400	39.93	39.91	(0.02)	-0.1%	10.0	33.62	31.86	(1.76)	-5.2%	8.0
12	450	44.90	44.88	(0.03)	-0.1%	10.0	37.80	35.82	(1.98)	-5.2%	8.0
13	500	49.87	49.84	(0.03)	-0.1%	10.0	41.98	39.78	(2.19)	-5.2%	8.0
14	600	59.80	59.77	(0.03)	-0.1%	10.0	50.33	47.70	(2.63)	-5.2%	7.9
15	700	69.74	69.70	(0.04)	-0.1%	10.0	58.69	55.61	(3.07)	-5.2%	7.9
16	800	79.67	79.62	(0.05)	-0.1%	10.0	67.04	63.53	(3.51)	-5.2%	7.9
17	900	89.60	89.55	(0.05)	-0.1%	10.0	75.40	71.45	(3.95)	-5.2%	7.9
18	1,000	99.54	99.48	(0.06)	-0.1%	9.9	83.75	79.36	(4.39)	-5.2%	7.9
19	1,500	149.21	149.12	(0.09)	-0.1%	9.9	125.53	118.94	(6.58)	-5.2%	7.9
20	2,000	198.87	198.76	(0.11)	-0.1%	9.9	167.30	158.52	(8.78)	-5.2%	7.9
21	2,500	248.54	248.40	(0.14)	-0.1%	9.9	209.08	198.10	(10.97)	-5.2%	7.9
22	3,000	298.21	298.04	(0.17)	-0.1%	9.9	250.85	237.68	(13.17)	-5.3%	7.9
23	3,500	347.88	347.68	(0.20)	-0.1%	9.9	292.63	277.26	(15.36)	-5.3%	7.9
24	4,000	397.55	397.32	(0.23)	-0.1%	9.9	334.40	316.84	(17.56)	-5.3%	7.9
25	4,500	447.22	446.96	(0.26)	-0.1%	9.9	376.18	356.43	(19.75)	-5.3%	7.9
26	5,000	496.88	496.60	(0.28)	-0.1%	9.9	417.96	396.01	(21.95)	-5.3%	7.9
27	5,500	546.55	546.24	(0.31)	-0.1%	9.9	459.73	435.59	(24.14)	-5.3%	7.9
28	6,000	596.22	595.88	(0.34)	-0.1%	9.9	501.51	475.17	(26.34)	-5.3%	7.9
29	6,500	645.89	645.52	(0.37)	-0.1%	9.9	543.28	514.75	(28.53)	-5.3%	7.9

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 34 of 46
Witness: LMConnolly
Date: June 2025

	(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	11.52	11.43	(0.10)	-0.8%	11.4	9.85	9.35	(0.50)	-5.1%	9.3
2	110	12.65	12.55	(0.11)	-0.8%	11.4	10.81	10.26	(0.55)	-5.1%	9.3
3	120	13.79	13.67	(0.11)	-0.8%	11.4	11.78	11.18	(0.60)	-5.1%	9.3
4	130	14.92	14.79	(0.12)	-0.8%	11.4	12.74	12.09	(0.65)	-5.1%	9.3
5	140	16.05	15.92	(0.13)	-0.8%	11.4	13.71	13.01	(0.70)	-5.1%	9.3
6	150	17.18	17.04	(0.14)	-0.8%	11.4	14.67	13.92	(0.75)	-5.1%	9.3
7	200	22.84	22.65	(0.19)	-0.8%	11.3	19.50	18.50	(1.00)	-5.1%	9.2
8	250	28.51	28.27	(0.24)	-0.8%	11.3	24.32	23.07	(1.25)	-5.1%	9.2
9	300	34.17	33.88	(0.29)	-0.8%	11.3	29.15	27.65	(1.50)	-5.2%	9.2
10	350	39.83	39.49	(0.33)	-0.8%	11.3	33.97	32.22	(1.75)	-5.2%	9.2
11	400	45.49	45.11	(0.38)	-0.8%	11.3	38.80	36.79	(2.00)	-5.2%	9.2
12	450	51.15	50.72	(0.43)	-0.8%	11.3	43.62	41.37	(2.25)	-5.2%	9.2
13	500	56.81	56.33	(0.48)	-0.8%	11.3	48.45	45.94	(2.50)	-5.2%	9.2
14	600	68.13	67.56	(0.57)	-0.8%	11.3	58.10	55.09	(3.00)	-5.2%	9.2
15	700	79.46	78.79	(0.67)	-0.8%	11.3	67.74	64.24	(3.51)	-5.2%	9.2
16	800	90.78	90.01	(0.77)	-0.8%	11.3	77.39	73.39	(4.01)	-5.2%	9.2
17	900	102.10	101.24	(0.86)	-0.8%	11.2	87.04	82.54	(4.51)	-5.2%	9.2
18	1,000	113.42	112.47	(0.96)	-0.8%	11.2	96.69	91.68	(5.01)	-5.2%	9.2
19	1,500	170.03	168.60	(1.44)	-0.8%	11.2	144.94	137.43	(7.51)	-5.2%	9.2
20	2,000	226.65	224.73	(1.91)	-0.8%	11.2	193.18	183.17	(10.02)	-5.2%	9.2
21	2,500	283.26	280.86	(2.39)	-0.8%	11.2	241.43	228.91	(12.52)	-5.2%	9.2
22	3,000	339.87	337.00	(2.87)	-0.8%	11.2	289.68	274.65	(15.02)	-5.2%	9.2
23	3,500	396.48	393.13	(3.35)	-0.8%	11.2	337.92	320.39	(17.53)	-5.2%	9.2
24	4,000	453.09	449.26	(3.83)	-0.8%	11.2	386.17	366.14	(20.03)	-5.2%	9.2
25	4,500	509.70	505.39	(4.31)	-0.8%	11.2	434.41	411.88	(22.54)	-5.2%	9.2
26	5,000	566.31	561.53	(4.79)	-0.8%	11.2	482.66	457.62	(25.04)	-5.2%	9.2
27	5,500	622.92	617.66	(5.26)	-0.8%	11.2	530.91	503.36	(27.54)	-5.2%	9.2
28	6,000	679.54	673.79	(5.74)	-0.8%	11.2	579.15	549.10	(30.05)	-5.2%	9.2
29	6,500	736.15	729.93	(6.22)	-0.8%	11.2	614.99	594.85	(20.14)	-3.3%	9.2

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 35 of 46
Witness: LMConnolly
Date: June 2025

	(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	8.63	8.45	(0.18)	-2.1%	8.4	7.21	6.56	(0.65)	-9.0%	6.6
2	110	9.48	9.27	(0.20)	-2.1%	8.4	7.91	7.20	(0.71)	-9.0%	6.5
3	120	10.32	10.10	(0.22)	-2.1%	8.4	8.61	7.83	(0.78)	-9.0%	6.5
4	130	11.16	10.92	(0.24)	-2.1%	8.4	9.32	8.47	(0.84)	-9.1%	6.5
5	140	12.00	11.75	(0.26)	-2.1%	8.4	10.02	9.11	(0.91)	-9.1%	6.5
6	150	12.85	12.57	(0.27)	-2.1%	8.4	10.72	9.74	(0.97)	-9.1%	6.5
7	200	17.06	16.70	(0.36)	-2.1%	8.3	14.22	12.92	(1.30)	-9.1%	6.5
8	250	21.28	20.82	(0.46)	-2.1%	8.3	17.73	16.11	(1.62)	-9.2%	6.4
9	300	25.50	24.95	(0.55)	-2.1%	8.3	21.23	19.29	(1.95)	-9.2%	6.4
10	350	29.71	29.07	(0.64)	-2.1%	8.3	24.74	22.47	(2.27)	-9.2%	6.4
11	400	33.93	33.20	(0.73)	-2.1%	8.3	28.25	25.65	(2.60)	-9.2%	6.4
12	450	38.14	37.32	(0.82)	-2.1%	8.3	31.75	28.83	(2.92)	-9.2%	6.4
13	500	42.36	41.45	(0.91)	-2.2%	8.3	35.26	32.01	(3.25)	-9.2%	6.4
14	600	50.79	49.70	(1.09)	-2.2%	8.3	42.27	38.37	(3.90)	-9.2%	6.4
15	700	59.22	57.95	(1.28)	-2.2%	8.3	49.28	44.74	(4.55)	-9.2%	6.4
16	800	67.66	66.20	(1.46)	-2.2%	8.3	56.29	51.10	(5.19)	-9.2%	6.4
17	900	76.09	74.45	(1.64)	-2.2%	8.3	63.30	57.46	(5.84)	-9.2%	6.4
18	1,000	84.52	82.70	(1.82)	-2.2%	8.3	70.32	63.82	(6.49)	-9.2%	6.4
19	1,500	126.68	123.95	(2.73)	-2.2%	8.3	105.37	95.63	(9.74)	-9.2%	6.4
20	2,000	168.84	165.20	(3.64)	-2.2%	8.3	140.43	127.45	(12.99)	-9.2%	6.4
21	2,500	211.00	206.44	(4.56)	-2.2%	8.3	175.49	159.26	(16.23)	-9.3%	6.4
22	3,000	253.16	247.69	(5.47)	-2.2%	8.3	210.55	191.07	(19.48)	-9.3%	6.4
23	3,500	295.32	288.94	(6.38)	-2.2%	8.3	245.61	222.88	(22.73)	-9.3%	6.4
24	4,000	337.48	330.19	(7.29)	-2.2%	8.3	280.67	254.69	(25.97)	-9.3%	6.4
25	4,500	379.64	371.44	(8.20)	-2.2%	8.3	315.72	286.50	(29.22)	-9.3%	6.4
26	5,000	421.80	412.69	(9.11)	-2.2%	8.3	350.78	318.32	(32.47)	-9.3%	6.4
27	5,500	463.96	453.94	(10.02)	-2.2%	8.3	385.84	350.13	(35.71)	-9.3%	6.4
28	6,000	506.12	495.19	(10.93)	-2.2%	8.3	420.90	381.94	(38.96)	-9.3%	6.4
29	6,500	548.28	536.43	(11.84)	-2.2%	8.3	455.96	413.75	(42.21)	-9.3%	6.4

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 36 of 46
Witness: LMConnolly
Date: June 2025

	(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	10.91	10.48	(0.43)	-3.9%	10.5	9.55	8.65	(0.90)	-9.5%	8.6
2	110	11.98	11.51	(0.47)	-3.9%	10.5	10.49	9.49	(1.00)	-9.5%	8.6
3	120	13.05	12.53	(0.52)	-4.0%	10.4	11.42	10.34	(1.09)	-9.5%	8.6
4	130	14.12	13.56	(0.56)	-4.0%	10.4	12.36	11.18	(1.18)	-9.5%	8.6
5	140	15.19	14.59	(0.60)	-4.0%	10.4	13.29	12.03	(1.27)	-9.5%	8.6
6	150	16.26	15.62	(0.64)	-4.0%	10.4	14.23	12.87	(1.36)	-9.5%	8.6
7	200	21.62	20.76	(0.86)	-4.0%	10.4	18.91	17.10	(1.81)	-9.6%	8.5
8	250	26.97	25.90	(1.07)	-4.0%	10.4	23.58	21.32	(2.26)	-9.6%	8.5
9	300	32.32	31.04	(1.29)	-4.0%	10.3	28.26	25.54	(2.71)	-9.6%	8.5
10	350	37.68	36.17	(1.50)	-4.0%	10.3	32.94	29.77	(3.17)	-9.6%	8.5
11	400	43.03	41.31	(1.72)	-4.0%	10.3	37.61	33.99	(3.62)	-9.6%	8.5
12	450	48.39	46.45	(1.93)	-4.0%	10.3	42.29	38.22	(4.07)	-9.6%	8.5
13	500	53.74	51.59	(2.15)	-4.0%	10.3	46.97	42.44	(4.52)	-9.6%	8.5
14	600	64.45	61.87	(2.58)	-4.0%	10.3	56.32	50.89	(5.43)	-9.6%	8.5
15	700	75.16	72.15	(3.01)	-4.0%	10.3	65.67	59.34	(6.33)	-9.6%	8.5
16	800	85.87	82.43	(3.44)	-4.0%	10.3	75.02	67.79	(7.24)	-9.6%	8.5
17	900	96.57	92.71	(3.87)	-4.0%	10.3	84.38	76.23	(8.14)	-9.7%	8.5
18	1,000	107.28	102.99	(4.30)	-4.0%	10.3	93.73	84.68	(9.05)	-9.7%	8.5
19	1,500	160.82	154.38	(6.45)	-4.0%	10.3	140.50	126.92	(13.57)	-9.7%	8.5
20	2,000	214.36	205.77	(8.59)	-4.0%	10.3	187.26	169.17	(18.10)	-9.7%	8.5
21	2,500	267.91	257.16	(10.74)	-4.0%	10.3	234.03	211.41	(22.62)	-9.7%	8.5
22	3,000	321.45	308.56	(12.89)	-4.0%	10.3	280.79	253.65	(27.14)	-9.7%	8.5
23	3,500	374.99	359.95	(15.04)	-4.0%	10.3	327.56	295.89	(31.67)	-9.7%	8.5
24	4,000	428.53	411.34	(17.19)	-4.0%	10.3	374.32	338.13	(36.19)	-9.7%	8.5
25	4,500	482.07	462.73	(19.34)	-4.0%	10.3	421.09	380.37	(40.72)	-9.7%	8.5
26	5,000	535.61	514.13	(21.48)	-4.0%	10.3	467.86	422.61	(45.24)	-9.7%	8.5
27	5,500	589.15	565.52	(23.63)	-4.0%	10.3	514.62	464.86	(49.77)	-9.7%	8.5
28	6,000	642.69	616.91	(25.78)	-4.0%	10.3	561.39	507.10	(54.29)	-9.7%	8.5
29	6,500	696.23	668.30	(27.93)	-4.0%	10.3	608.15	549.34	(58.81)	-9.7%	8.5

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Energy Intensive EIP Voltage Level 3

Case No.: U-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 37 of 46
Witness: LMConnolly
Date: June 2025

	(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	13.57	12.93	(0.65)	-4.8%	12.9	11.54	10.44	(1.10)	-9.6%	10.4
2	110	14.91	14.20	(0.71)	-4.8%	12.9	12.68	11.46	(1.21)	-9.6%	10.4
3	120	16.25	15.47	(0.77)	-4.8%	12.9	13.81	12.49	(1.32)	-9.6%	10.4
4	130	17.59	16.75	(0.84)	-4.8%	12.9	14.94	13.51	(1.43)	-9.6%	10.4
5	140	18.92	18.02	(0.90)	-4.8%	12.9	16.08	14.54	(1.54)	-9.6%	10.4
6	150	20.26	19.29	(0.97)	-4.8%	12.9	17.21	15.56	(1.65)	-9.6%	10.4
7	200	26.95	25.66	(1.29)	-4.8%	12.8	22.88	20.68	(2.20)	-9.6%	10.3
8	250	33.63	32.02	(1.61)	-4.8%	12.8	28.55	25.80	(2.76)	-9.7%	10.3
9	300	40.32	38.38	(1.94)	-4.8%	12.8	34.23	30.92	(3.31)	-9.7%	10.3
10	350	47.01	44.75	(2.26)	-4.8%	12.8	39.90	36.04	(3.86)	-9.7%	10.3
11	400	53.70	51.11	(2.58)	-4.8%	12.8	45.57	41.16	(4.41)	-9.7%	10.3
12	450	60.38	57.48	(2.90)	-4.8%	12.8	51.24	46.28	(4.96)	-9.7%	10.3
13	500	67.07	63.84	(3.23)	-4.8%	12.8	56.91	51.40	(5.51)	-9.7%	10.3
14	600	80.44	76.57	(3.87)	-4.8%	12.8	68.25	61.64	(6.61)	-9.7%	10.3
15	700	93.82	89.30	(4.52)	-4.8%	12.8	79.59	71.88	(7.72)	-9.7%	10.3
16	800	107.19	102.03	(5.16)	-4.8%	12.8	90.94	82.12	(8.82)	-9.7%	10.3
17	900	120.56	114.75	(5.81)	-4.8%	12.8	102.28	92.35	(9.92)	-9.7%	10.3
18	1,000	133.94	127.48	(6.45)	-4.8%	12.7	113.62	102.59	(11.02)	-9.7%	10.3
19	1,500	200.81	191.12	(9.68)	-4.8%	12.7	170.33	153.79	(16.54)	-9.7%	10.3
20	2,000	267.68	254.77	(12.91)	-4.8%	12.7	227.04	204.99	(22.05)	-9.7%	10.2
21	2,500	334.54	318.41	(16.14)	-4.8%	12.7	283.75	256.19	(27.56)	-9.7%	10.2
22	3,000	401.41	382.05	(19.36)	-4.8%	12.7	340.46	307.38	(33.07)	-9.7%	10.2
23	3,500	468.28	445.69	(22.59)	-4.8%	12.7	397.17	358.58	(38.59)	-9.7%	10.2
24	4,000	535.15	509.33	(25.82)	-4.8%	12.7	453.88	409.78	(44.10)	-9.7%	10.2
25	4,500	602.02	572.97	(29.05)	-4.8%	12.7	510.59	460.97	(49.61)	-9.7%	10.2
26	5,000	668.89	636.62	(32.27)	-4.8%	12.7	567.30	512.17	(55.12)	-9.7%	10.2
27	5,500	735.76	700.26	(35.50)	-4.8%	12.7	624.01	563.37	(60.64)	-9.7%	10.2
28	6,000	802.63	763.90	(38.73)	-4.8%	12.7	680.71	614.57	(66.15)	-9.7%	10.2
29	6,500	869.50	827.54	(41.96)	-4.8%	12.7	737.42	665.76	(71.66)	-9.7%	10.2

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 38 of 46
Witness: LMConnolly
Date: June 2025

	(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	36.07	39.07	3.00	8.3%	15.6	36.07	39.07	3.00	8.3%	15.6
2	500	52.13	58.14	6.00	11.5%	11.6	52.13	58.14	6.00	11.5%	11.6
3	750	68.20	77.20	9.01	13.2%	10.3	68.20	77.20	9.01	13.2%	10.3
4	1,000	84.27	96.27	12.01	14.2%	9.6	84.27	96.27	12.01	14.2%	9.6
5	1,500	116.40	134.41	18.01	15.5%	9.0	116.40	134.41	18.01	15.5%	9.0
6	2,000	148.53	172.55	24.01	16.2%	8.6	148.53	172.55	24.01	16.2%	8.6
7	2,500	180.67	210.68	30.02	16.6%	8.4	180.67	210.68	30.02	16.6%	8.4
8	3,000	212.80	248.82	36.02	16.9%	8.3	212.80	248.82	36.02	16.9%	8.3
9	3,500	244.93	286.96	42.02	17.2%	8.2	244.93	286.96	42.02	17.2%	8.2
10	4,000	277.06	325.09	48.03	17.3%	8.1	277.06	325.09	48.03	17.3%	8.1
11	4,500	309.20	363.23	54.03	17.5%	8.1	309.20	363.23	54.03	17.5%	8.1
12	5,000	341.33	401.37	60.04	17.6%	8.0	341.33	401.37	60.04	17.6%	8.0
13	6,000	405.60	477.64	72.04	17.8%	8.0	405.60	477.64	72.04	17.8%	8.0
14	7,000	469.86	553.91	84.05	17.9%	7.9	469.86	553.91	84.05	17.9%	7.9
15	8,000	534.13	630.18	96.06	18.0%	7.9	534.13	630.18	96.06	18.0%	7.9
16	9,000	598.39	706.46	108.06	18.1%	7.8	598.39	706.46	108.06	18.1%	7.8
17	10,000	662.66	782.73	120.07	18.1%	7.8	662.66	782.73	120.07	18.1%	7.8
18	15,000	983.99	1,164.10	180.11	18.3%	7.8	983.99	1,164.10	180.11	18.3%	7.8
19	20,000	1,305.32	1,545.46	240.14	18.4%	7.7	1,305.32	1,545.46	240.14	18.4%	7.7
20	25,000	1,626.65	1,926.83	300.18	18.5%	7.7	1,626.65	1,926.83	300.18	18.5%	7.7
21	30,000	1,947.98	2,308.19	360.21	18.5%	7.7	1,947.98	2,308.19	360.21	18.5%	7.7
22	35,000	2,269.31	2,689.56	420.25	18.5%	7.7	2,269.31	2,689.56	420.25	18.5%	7.7
23	40,000	2,590.64	3,070.92	480.28	18.5%	7.7	2,590.64	3,070.92	480.28	18.5%	7.7
24	45,000	2,911.97	3,452.29	540.32	18.6%	7.7	2,911.97	3,452.29	540.32	18.6%	7.7
25	50,000	3,233.30	3,833.65	600.35	18.6%	7.7	3,233.30	3,833.65	600.35	18.6%	7.7
26	55,000	3,554.63	4,215.02	660.39	18.6%	7.7	3,554.63	4,215.02	660.39	18.6%	7.7
27	60,000	3,875.96	4,596.38	720.42	18.6%	7.7	3,875.96	4,596.38	720.42	18.6%	7.7
28	65,000	4,197.29	4,977.75	780.46	18.6%	7.7	4,197.29	4,977.75	780.46	18.6%	7.7
29	70,000	4,518.62	5,359.11	840.49	18.6%	7.7	4,518.62	5,359.11	840.49	18.6%	7.7

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 39 of 46
Witness: LMConnolly
Date: June 2025

	(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	55.97	62.72	6.75	12.1%	12.5	55.97	62.72	6.75	12.1%	12.5
2	1,000	81.94	95.43	13.49	16.5%	9.5	81.94	95.43	13.49	16.5%	9.5
3	1,500	107.91	128.15	20.24	18.8%	8.5	107.91	128.15	20.24	18.8%	8.5
4	2,000	133.89	160.87	26.98	20.2%	8.0	133.89	160.87	26.98	20.2%	8.0
5	2,500	159.86	193.58	33.73	21.1%	7.7	159.86	193.58	33.73	21.1%	7.7
6	3,000	185.83	226.30	40.47	21.8%	7.5	185.83	226.30	40.47	21.8%	7.5
7	3,500	211.80	259.02	47.22	22.3%	7.4	211.80	259.02	47.22	22.3%	7.4
8	4,000	237.77	291.74	53.96	22.7%	7.3	237.77	291.74	53.96	22.7%	7.3
9	4,500	263.74	324.45	60.71	23.0%	7.2	263.74	324.45	60.71	23.0%	7.2
10	5,000	289.71	357.17	67.46	23.3%	7.1	289.71	357.17	67.46	23.3%	7.1
11	6,000	341.66	422.60	80.95	23.7%	7.0	341.66	422.60	80.95	23.7%	7.0
12	7,000	393.60	488.04	94.44	24.0%	7.0	393.60	488.04	94.44	24.0%	7.0
13	8,000	445.54	553.47	107.93	24.2%	6.9	445.54	553.47	107.93	24.2%	6.9
14	9,000	497.49	618.91	121.42	24.4%	6.9	497.49	618.91	121.42	24.4%	6.9
15	10,000	549.43	684.34	134.91	24.6%	6.8	549.43	684.34	134.91	24.6%	6.8
16	11,000	601.37	749.77	148.40	24.7%	6.8	601.37	749.77	148.40	24.7%	6.8
17	12,000	653.32	815.21	161.89	24.8%	6.8	653.32	815.21	161.89	24.8%	6.8
18	13,000	705.26	880.64	175.38	24.9%	6.8	705.26	880.64	175.38	24.9%	6.8
19	14,000	757.20	946.08	188.87	24.9%	6.8	757.20	946.08	188.87	24.9%	6.8
20	15,000	809.14	1,011.51	202.37	25.0%	6.7	809.14	1,011.51	202.37	25.0%	6.7
21	16,000	861.09	1,076.94	215.86	25.1%	6.7	861.09	1,076.94	215.86	25.1%	6.7
22	17,000	913.03	1,142.38	229.35	25.1%	6.7	913.03	1,142.38	229.35	25.1%	6.7
23	18,000	964.97	1,207.81	242.84	25.2%	6.7	964.97	1,207.81	242.84	25.2%	6.7
24	19,000	1,016.92	1,273.25	256.33	25.2%	6.7	1,016.92	1,273.25	256.33	25.2%	6.7
25	20,000	1,068.86	1,338.68	269.82	25.2%	6.7	1,068.86	1,338.68	269.82	25.2%	6.7
26	21,000	1,120.80	1,404.11	283.31	25.3%	6.7	1,120.80	1,404.11	283.31	25.3%	6.7
27	22,000	1,172.75	1,469.55	296.80	25.3%	6.7	1,172.75	1,469.55	296.80	25.3%	6.7
28	23,000	1,224.69	1,534.98	310.29	25.3%	6.7	1,224.69	1,534.98	310.29	25.3%	6.7
29	24,000	1,276.63	1,600.42	323.78	25.4%	6.7	1,276.63	1,600.42	323.78	25.4%	6.7

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 40 of 46
Witness: LMConnolly
Date: June 2025

	(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	52.13	58.14	6.00	11.5%	11.6	52.13	58.14	6.00	11.5%	11.6
2	1,000	84.27	96.27	12.01	14.2%	9.6	84.27	96.27	12.01	14.2%	9.6
3	1,500	116.40	134.41	18.01	15.5%	9.0	116.40	134.41	18.01	15.5%	9.0
4	2,000	148.53	172.55	24.01	16.2%	8.6	148.53	172.55	24.01	16.2%	8.6
5	2,500	180.67	210.68	30.02	16.6%	8.4	180.67	210.68	30.02	16.6%	8.4
6	3,000	212.80	248.82	36.02	16.9%	8.3	212.80	248.82	36.02	16.9%	8.3
7	3,500	244.93	286.96	42.02	17.2%	8.2	244.93	286.96	42.02	17.2%	8.2
8	4,000	277.06	325.09	48.03	17.3%	8.1	277.06	325.09	48.03	17.3%	8.1
9	4,500	309.20	363.23	54.03	17.5%	8.1	309.20	363.23	54.03	17.5%	8.1
10	5,000	341.33	401.37	60.04	17.6%	8.0	341.33	401.37	60.04	17.6%	8.0
11	6,000	405.60	477.64	72.04	17.8%	8.0	405.60	477.64	72.04	17.8%	8.0
12	7,000	469.86	553.91	84.05	17.9%	7.9	469.86	553.91	84.05	17.9%	7.9
13	8,000	534.13	630.18	96.06	18.0%	7.9	534.13	630.18	96.06	18.0%	7.9
14	9,000	598.39	706.46	108.06	18.1%	7.8	598.39	706.46	108.06	18.1%	7.8
15	10,000	662.66	782.73	120.07	18.1%	7.8	662.66	782.73	120.07	18.1%	7.8
16	11,000	726.93	859.00	132.08	18.2%	7.8	726.93	859.00	132.08	18.2%	7.8
17	12,000	791.19	935.28	144.08	18.2%	7.8	791.19	935.28	144.08	18.2%	7.8
18	13,000	855.46	1,011.55	156.09	18.2%	7.8	855.46	1,011.55	156.09	18.2%	7.8
19	14,000	919.72	1,087.82	168.10	18.3%	7.8	919.72	1,087.82	168.10	18.3%	7.8
20	15,000	983.99	1,164.10	180.11	18.3%	7.8	983.99	1,164.10	180.11	18.3%	7.8
21	16,000	1,048.26	1,240.37	192.11	18.3%	7.8	1,048.26	1,240.37	192.11	18.3%	7.8
22	17,000	1,112.52	1,316.64	204.12	18.3%	7.7	1,112.52	1,316.64	204.12	18.3%	7.7
23	18,000	1,176.79	1,392.91	216.13	18.4%	7.7	1,176.79	1,392.91	216.13	18.4%	7.7
24	19,000	1,241.05	1,469.19	228.13	18.4%	7.7	1,241.05	1,469.19	228.13	18.4%	7.7
25	20,000	1,305.32	1,545.46	240.14	18.4%	7.7	1,305.32	1,545.46	240.14	18.4%	7.7
26	21,000	1,369.59	1,621.73	252.15	18.4%	7.7	1,369.59	1,621.73	252.15	18.4%	7.7
27	22,000	1,433.85	1,698.01	264.15	18.4%	7.7	1,433.85	1,698.01	264.15	18.4%	7.7
28	23,000	1,498.12	1,774.28	276.16	18.4%	7.7	1,498.12	1,774.28	276.16	18.4%	7.7
29	24,000	1,562.38	1,850.55	288.17	18.4%	7.7	1,562.38	1,850.55	288.17	18.4%	7.7

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 41 of 46
Witness: LMConnolly
Date: June 2025

	(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	101.49	103.84	2.34	2.3%	20.8	101.49	103.84	2.34	2.3%	20.8
2	1,000	102.99	107.68	4.69	4.6%	10.8	102.99	107.68	4.69	4.6%	10.8
3	1,500	104.48	111.51	7.03	6.7%	7.4	104.48	111.51	7.03	6.7%	7.4
4	2,000	105.97	115.35	9.38	8.8%	5.8	105.97	115.35	9.38	8.8%	5.8
5	2,500	107.47	119.19	11.72	10.9%	4.8	107.47	119.19	11.72	10.9%	4.8
6	3,000	108.96	123.03	14.07	12.9%	4.1	108.96	123.03	14.07	12.9%	4.1
7	4,000	111.94	130.70	18.76	16.8%	3.3	111.94	130.70	18.76	16.8%	3.3
8	5,000	114.93	138.38	23.45	20.4%	2.8	114.93	138.38	23.45	20.4%	2.8
9	6,000	117.92	146.05	28.13	23.9%	2.4	117.92	146.05	28.13	23.9%	2.4
10	7,000	120.90	153.73	32.82	27.1%	2.2	120.90	153.73	32.82	27.1%	2.2
11	8,000	123.89	161.40	37.51	30.3%	2.0	123.89	161.40	37.51	30.3%	2.0
12	9,000	126.87	169.08	42.20	33.3%	1.9	126.87	169.08	42.20	33.3%	1.9
13	10,000	129.86	176.75	46.89	36.1%	1.8	129.86	176.75	46.89	36.1%	1.8
14	15,000	144.79	215.13	70.34	48.6%	1.4	144.79	215.13	70.34	48.6%	1.4
15	20,000	159.72	253.50	93.78	58.7%	1.3	159.72	253.50	93.78	58.7%	1.3
16	25,000	174.65	291.88	117.23	67.1%	1.2	174.65	291.88	117.23	67.1%	1.2
17	30,000	189.58	330.25	140.67	74.2%	1.1	189.58	330.25	140.67	74.2%	1.1
18	35,000	204.51	368.63	164.12	80.2%	1.1	204.51	368.63	164.12	80.2%	1.1
19	40,000	219.44	407.00	187.56	85.5%	1.0	219.44	407.00	187.56	85.5%	1.0
20	45,000	234.37	445.38	211.01	90.0%	1.0	234.37	445.38	211.01	90.0%	1.0
21	50,000	249.30	483.75	234.45	94.0%	1.0	249.30	483.75	234.45	94.0%	1.0
22	60,000	279.16	560.50	281.34	100.8%	0.9	279.16	560.50	281.34	100.8%	0.9
23	70,000	309.02	637.25	328.23	106.2%	0.9	309.02	637.25	328.23	106.2%	0.9
24	80,000	338.88	714.00	375.12	110.7%	0.9	338.88	714.00	375.12	110.7%	0.9
25	90,000	368.74	790.75	422.01	114.4%	0.9	368.74	790.75	422.01	114.4%	0.9
26	100,000	398.60	867.50	468.90	117.6%	0.9	398.60	867.50	468.90	117.6%	0.9
27	110,000	428.46	944.25	515.79	120.4%	0.9	428.46	944.25	515.79	120.4%	0.9
28	120,000	458.32	1,021.00	562.68	122.8%	0.9	458.32	1,021.00	562.68	122.8%	0.9
29	130,000	488.18	1,097.75	609.57	124.9%	0.8	488.18	1,097.75	609.57	124.9%	0.8

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 42 of 46
Witness: LMConnolly
Date: June 2025

	(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	105.48	106.05	0.57	0.5%	21.2	105.48	106.05	0.57	0.5%	21.2
2	1,000	110.96	112.09	1.13	1.0%	11.2	110.96	112.09	1.13	1.0%	11.2
3	1,500	116.44	118.14	1.70	1.5%	7.9	116.44	118.14	1.70	1.5%	7.9
4	2,000	121.91	124.18	2.27	1.9%	6.2	121.91	124.18	2.27	1.9%	6.2
5	2,500	127.39	130.23	2.83	2.2%	5.2	127.39	130.23	2.83	2.2%	5.2
6	3,000	132.87	136.27	3.40	2.6%	4.5	132.87	136.27	3.40	2.6%	4.5
7	4,000	143.83	148.36	4.54	3.2%	3.7	143.83	148.36	4.54	3.2%	3.7
8	5,000	154.79	160.46	5.67	3.7%	3.2	154.79	160.46	5.67	3.7%	3.2
9	6,000	165.74	172.55	6.80	4.1%	2.9	165.74	172.55	6.80	4.1%	2.9
10	7,000	176.70	184.64	7.94	4.5%	2.6	176.70	184.64	7.94	4.5%	2.6
11	8,000	187.66	196.73	9.07	4.8%	2.5	187.66	196.73	9.07	4.8%	2.5
12	9,000	198.61	208.82	10.21	5.1%	2.3	198.61	208.82	10.21	5.1%	2.3
13	10,000	209.57	220.91	11.34	5.4%	2.2	209.57	220.91	11.34	5.4%	2.2
14	15,000	264.36	281.37	17.01	6.4%	1.9	264.36	281.37	17.01	6.4%	1.9
15	20,000	319.14	341.82	22.68	7.1%	1.7	319.14	341.82	22.68	7.1%	1.7
16	25,000	373.93	402.28	28.35	7.6%	1.6	373.93	402.28	28.35	7.6%	1.6
17	30,000	428.71	462.73	34.02	7.9%	1.5	428.71	462.73	34.02	7.9%	1.5
18	35,000	483.50	523.19	39.69	8.2%	1.5	483.50	523.19	39.69	8.2%	1.5
19	40,000	538.28	583.64	45.36	8.4%	1.5	538.28	583.64	45.36	8.4%	1.5
20	45,000	593.07	644.10	51.03	8.6%	1.4	593.07	644.10	51.03	8.6%	1.4
21	50,000	647.85	704.55	56.70	8.8%	1.4	647.85	704.55	56.70	8.8%	1.4
22	60,000	757.42	825.46	68.04	9.0%	1.4	757.42	825.46	68.04	9.0%	1.4
23	70,000	866.99	946.37	79.38	9.2%	1.4	866.99	946.37	79.38	9.2%	1.4
24	80,000	976.56	1,067.28	90.72	9.3%	1.3	976.56	1,067.28	90.72	9.3%	1.3
25	90,000	1,086.13	1,188.19	102.06	9.4%	1.3	1,086.13	1,188.19	102.06	9.4%	1.3
26	100,000	1,195.70	1,309.10	113.40	9.5%	1.3	1,195.70	1,309.10	113.40	9.5%	1.3
27	110,000	1,305.27	1,430.01	124.74	9.6%	1.3	1,305.27	1,430.01	124.74	9.6%	1.3
28	120,000	1,414.84	1,550.92	136.08	9.6%	1.3	1,414.84	1,550.92	136.08	9.6%	1.3
29	130,000	1,524.41	1,671.83	147.42	9.7%	1.3	1,524.41	1,671.83	147.42	9.7%	1.3

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
Page 43 of 46
Witness: LMConnolly
Date: June 2025

	(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	112.59	113.31	0.72	0.6%	22.7	112.59	113.31	0.72	0.6%	22.7
2	1,000	125.17	126.62	1.45	1.2%	12.7	125.17	126.62	1.45	1.2%	12.7
3	1,500	137.76	139.93	2.17	1.6%	9.3	137.76	139.93	2.17	1.6%	9.3
4	2,000	150.35	153.24	2.89	1.9%	7.7	150.35	153.24	2.89	1.9%	7.7
5	2,500	162.94	166.55	3.62	2.2%	6.7	162.94	166.55	3.62	2.2%	6.7
6	3,000	175.52	179.86	4.34	2.5%	6.0	175.52	179.86	4.34	2.5%	6.0
7	4,000	200.70	206.48	5.79	2.9%	5.2	200.70	206.48	5.79	2.9%	5.2
8	5,000	225.87	233.11	7.23	3.2%	4.7	225.87	233.11	7.23	3.2%	4.7
9	6,000	251.04	259.73	8.68	3.5%	4.3	251.04	259.73	8.68	3.5%	4.3
10	7,000	276.22	286.35	10.13	3.7%	4.1	276.22	286.35	10.13	3.7%	4.1
11	8,000	301.39	312.97	11.58	3.8%	3.9	301.39	312.97	11.58	3.8%	3.9
12	9,000	326.57	339.59	13.02	4.0%	3.8	326.57	339.59	13.02	4.0%	3.8
13	10,000	351.74	366.21	14.47	4.1%	3.7	351.74	366.21	14.47	4.1%	3.7
14	15,000	477.61	499.32	21.71	4.5%	3.3	477.61	499.32	21.71	4.5%	3.3
15	20,000	603.48	632.42	28.94	4.8%	3.2	603.48	632.42	28.94	4.8%	3.2
16	25,000	729.35	765.53	36.18	5.0%	3.1	729.35	765.53	36.18	5.0%	3.1
17	30,000	855.22	898.63	43.41	5.1%	3.0	855.22	898.63	43.41	5.1%	3.0
18	35,000	981.09	1,031.74	50.65	5.2%	2.9	981.09	1,031.74	50.65	5.2%	2.9
19	40,000	1,106.96	1,164.84	57.88	5.2%	2.9	1,106.96	1,164.84	57.88	5.2%	2.9
20	45,000	1,232.83	1,297.95	65.12	5.3%	2.9	1,232.83	1,297.95	65.12	5.3%	2.9
21	50,000	1,358.70	1,431.05	72.35	5.3%	2.9	1,358.70	1,431.05	72.35	5.3%	2.9
22	60,000	1,610.44	1,697.26	86.82	5.4%	2.8	1,610.44	1,697.26	86.82	5.4%	2.8
23	70,000	1,862.18	1,963.47	101.29	5.4%	2.8	1,862.18	1,963.47	101.29	5.4%	2.8
24	80,000	2,113.92	2,229.68	115.76	5.5%	2.8	2,113.92	2,229.68	115.76	5.5%	2.8
25	90,000	2,365.66	2,495.89	130.23	5.5%	2.8	2,365.66	2,495.89	130.23	5.5%	2.8
26	100,000	2,617.40	2,762.10	144.70	5.5%	2.8	2,617.40	2,762.10	144.70	5.5%	2.8
27	110,000	2,869.14	3,028.31	159.17	5.5%	2.8	2,869.14	3,028.31	159.17	5.5%	2.8
28	120,000	3,120.88	3,294.52	173.64	5.6%	2.7	3,120.88	3,294.52	173.64	5.6%	2.7
29	130,000	3,372.62	3,560.73	188.11	5.6%	2.7	3,321.27	3,560.73	239.46	7.2%	2.7

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	0.40	0.71	0.30	75.6%	0.7	0.40	0.71	0.30	75.6%	0.7
2	110	0.42	0.76	0.34	79.1%	0.7	0.42	0.76	0.34	79.1%	0.7
3	120	0.44	0.81	0.37	82.4%	0.7	0.44	0.81	0.37	82.4%	0.7
4	130	0.46	0.86	0.40	85.3%	0.7	0.46	0.86	0.40	85.3%	0.7
5	140	0.48	0.91	0.43	88.0%	0.7	0.48	0.91	0.43	88.0%	0.7
6	150	0.51	0.96	0.46	90.5%	0.6	0.51	0.96	0.46	90.5%	0.6
7	200	0.61	1.22	0.61	100.5%	0.6	0.61	1.22	0.61	100.5%	0.6
8	250	0.71	1.47	0.76	107.6%	0.6	0.71	1.47	0.76	107.6%	0.6
9	300	0.81	1.72	0.91	112.9%	0.6	0.81	1.72	0.91	112.9%	0.6
10	350	0.91	1.98	1.07	117.0%	0.6	0.91	1.98	1.07	117.0%	0.6
11	400	1.01	2.23	1.22	120.3%	0.6	1.01	2.23	1.22	120.3%	0.6
12	450	1.12	2.49	1.37	123.0%	0.6	1.12	2.49	1.37	123.0%	0.6
13	500	1.22	2.74	1.52	125.2%	0.5	1.22	2.74	1.52	125.2%	0.5
14	600	1.42	3.25	1.83	128.8%	0.5	1.42	3.25	1.83	128.8%	0.5
15	700	1.62	3.76	2.13	131.4%	0.5	1.62	3.76	2.13	131.4%	0.5
16	800	1.83	4.27	2.44	133.5%	0.5	1.83	4.27	2.44	133.5%	0.5
17	900	2.03	4.77	2.74	135.1%	0.5	2.03	4.77	2.74	135.1%	0.5
18	1,000	2.23	5.28	3.05	136.4%	0.5	2.23	5.28	3.05	136.4%	0.5
19	1,500	3.25	7.82	4.57	140.6%	0.5	3.25	7.82	4.57	140.6%	0.5
20	2,000	4.27	10.37	6.10	142.8%	0.5	4.27	10.37	6.10	142.8%	0.5
21	2,500	5.29	12.91	7.62	144.2%	0.5	5.29	12.91	7.62	144.2%	0.5
22	3,000	6.30	15.45	9.15	145.1%	0.5	6.30	15.45	9.15	145.1%	0.5
23	3,500	7.32	17.99	10.67	145.8%	0.5	7.32	17.99	10.67	145.8%	0.5
24	4,000	8.34	20.53	12.19	146.3%	0.5	8.34	20.53	12.19	146.3%	0.5
25	4,500	9.35	23.07	13.72	146.6%	0.5	9.35	23.07	13.72	146.6%	0.5
26	5,000	10.37	25.62	15.24	147.0%	0.5	10.37	25.62	15.24	147.0%	0.5
27	5,500	11.39	28.16	16.77	147.2%	0.5	11.39	28.16	16.77	147.2%	0.5
28	6,000	12.41	30.70	18.29	147.4%	0.5	12.41	30.70	18.29	147.4%	0.5
29	6,500	13.42	33.24	19.82	147.6%	0.5	13.42	33.24	19.82	147.6%	0.5

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-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	0.95	1.03	0.08	8.4%	1.0	0.95	1.03	0.08	8.4%	1.0
2	110	1.02	1.11	0.09	8.5%	1.0	1.02	1.11	0.09	8.5%	1.0
3	120	1.10	1.19	0.10	8.7%	1.0	1.10	1.19	0.10	8.7%	1.0
4	130	1.17	1.28	0.10	8.8%	1.0	1.17	1.28	0.10	8.8%	1.0
5	140	1.25	1.36	0.11	8.9%	1.0	1.25	1.36	0.11	8.9%	1.0
6	150	1.32	1.44	0.12	9.0%	1.0	1.32	1.44	0.12	9.0%	1.0
7	200	1.70	1.85	0.16	9.3%	0.9	1.70	1.85	0.16	9.3%	0.9
8	250	2.07	2.27	0.20	9.6%	0.9	2.07	2.27	0.20	9.6%	0.9
9	300	2.44	2.68	0.24	9.7%	0.9	2.44	2.68	0.24	9.7%	0.9
10	350	2.82	3.09	0.28	9.8%	0.9	2.82	3.09	0.28	9.8%	0.9
11	400	3.19	3.51	0.32	9.9%	0.9	3.19	3.51	0.32	9.9%	0.9
12	450	3.57	3.92	0.36	10.0%	0.9	3.57	3.92	0.36	10.0%	0.9
13	500	3.94	4.34	0.40	10.0%	0.9	3.94	4.34	0.40	10.0%	0.9
14	600	4.69	5.16	0.48	10.1%	0.9	4.69	5.16	0.48	10.1%	0.9
15	700	5.44	5.99	0.55	10.2%	0.9	5.44	5.99	0.55	10.2%	0.9
16	800	6.18	6.82	0.63	10.2%	0.9	6.18	6.82	0.63	10.2%	0.9
17	900	6.93	7.64	0.71	10.3%	0.8	6.93	7.64	0.71	10.3%	0.8
18	1,000	7.68	8.47	0.79	10.3%	0.8	7.68	8.47	0.79	10.3%	0.8
19	1,500	11.42	12.61	1.19	10.4%	0.8	11.42	12.61	1.19	10.4%	0.8
20	2,000	15.16	16.74	1.58	10.4%	0.8	15.16	16.74	1.58	10.4%	0.8
21	2,500	18.90	20.88	1.98	10.5%	0.8	18.90	20.88	1.98	10.5%	0.8
22	3,000	22.64	25.01	2.38	10.5%	0.8	22.64	25.01	2.38	10.5%	0.8
23	3,500	26.38	29.15	2.77	10.5%	0.8	26.38	29.15	2.77	10.5%	0.8
24	4,000	30.12	33.28	3.17	10.5%	0.8	30.12	33.28	3.17	10.5%	0.8
25	4,500	33.86	37.42	3.56	10.5%	0.8	33.86	37.42	3.56	10.5%	0.8
26	5,000	37.60	41.55	3.96	10.5%	0.8	37.60	41.55	3.96	10.5%	0.8
27	5,500	41.34	45.69	4.35	10.5%	0.8	41.34	45.69	4.35	10.5%	0.8
28	6,000	45.08	49.83	4.75	10.5%	0.8	45.08	49.83	4.75	10.5%	0.8
29	6,500	48.81	53.96	5.15	10.5%	0.8	48.81	53.96	5.15	10.5%	0.8

Schedule F-4.0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills

Primary Demand GPD Voltage Level 3
Retail Open Acess

Case No.: U-21870
Exhibit No.: A-16 (LMC-4)
Schedule F-4.0
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Witness: LMConnolly
Date: June 2025

	(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	2.13	2.17	0.03	1.6%	2.2	2.13	2.17	0.03	1.6%	2.2
2	110	2.33	2.36	0.04	1.6%	2.1	2.33	2.36	0.04	1.6%	2.1
3	120	2.52	2.56	0.04	1.7%	2.1	2.52	2.56	0.04	1.7%	2.1
4	130	2.71	2.76	0.05	1.7%	2.1	2.71	2.76	0.05	1.7%	2.1
5	140	2.90	2.95	0.05	1.7%	2.1	2.90	2.95	0.05	1.7%	2.1
6	150	3.10	3.15	0.05	1.7%	2.1	3.10	3.15	0.05	1.7%	2.1
7	200	4.06	4.13	0.07	1.7%	2.1	4.06	4.13	0.07	1.7%	2.1
8	250	5.03	5.12	0.09	1.7%	2.0	5.03	5.12	0.09	1.7%	2.0
9	300	6.00	6.10	0.10	1.7%	2.0	6.00	6.10	0.10	1.7%	2.0
10	350	6.96	7.08	0.12	1.7%	2.0	6.96	7.08	0.12	1.7%	2.0
11	400	7.93	8.07	0.14	1.8%	2.0	7.93	8.07	0.14	1.8%	2.0
12	450	8.89	9.05	0.16	1.8%	2.0	8.89	9.05	0.16	1.8%	2.0
13	500	9.86	10.03	0.17	1.8%	2.0	9.86	10.03	0.17	1.8%	2.0
14	600	11.79	12.00	0.21	1.8%	2.0	11.79	12.00	0.21	1.8%	2.0
15	700	13.72	13.97	0.24	1.8%	2.0	13.72	13.97	0.24	1.8%	2.0
16	800	15.65	15.93	0.28	1.8%	2.0	15.65	15.93	0.28	1.8%	2.0
17	900	17.59	17.90	0.31	1.8%	2.0	17.59	17.90	0.31	1.8%	2.0
18	1,000	19.52	19.87	0.35	1.8%	2.0	19.52	19.87	0.35	1.8%	2.0
19	1,500	29.18	29.70	0.52	1.8%	2.0	29.18	29.70	0.52	1.8%	2.0
20	2,000	38.84	39.53	0.69	1.8%	2.0	38.84	39.53	0.69	1.8%	2.0
21	2,500	48.50	49.36	0.87	1.8%	2.0	48.50	49.36	0.87	1.8%	2.0
22	3,000	58.16	59.20	1.04	1.8%	2.0	58.16	59.20	1.04	1.8%	2.0
23	3,500	67.81	69.03	1.21	1.8%	2.0	67.81	69.03	1.21	1.8%	2.0
24	4,000	77.47	78.86	1.39	1.8%	2.0	77.47	78.86	1.39	1.8%	2.0
25	4,500	87.13	88.70	1.56	1.8%	2.0	87.13	88.70	1.56	1.8%	2.0
26	5,000	96.79	98.53	1.74	1.8%	2.0	96.79	98.53	1.74	1.8%	2.0
27	5,500	106.45	108.36	1.91	1.8%	2.0	106.45	108.36	1.91	1.8%	2.0
28	6,000	116.11	118.19	2.08	1.8%	2.0	116.11	118.19	2.08	1.8%	2.0
29	6,500	125.77	128.03	2.26	1.8%	2.0	125.77	128.03	2.26	1.8%	2.0

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 (LMC-3) Schedule F-3.0, pages 1-23

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. A-4.00**

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M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. A-5.00**

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POLE ATTACHMENT AND CONDUIT USE RATE PA	D-99.00

(Continued on Sheet No. A-6.00)

See Gray Testimony, Page 5, Lines 10-15; Exhibit A-96 (Gray-1), Item No. 1

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-4.00**

(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	*$0.011/kWh* ~~$0.008/kWh~~	*$0.021/kWh* ~~$0.016/kWh~~	*$0.030/kWh* ~~$0.023/kWh~~	*$0.039/kWh* ~~$0.030/kWh~~	*$0.047/kWh* ~~$0.036/kWh~~	*$0.011/kWh* ~~$0.008/kWh~~
	2	$0.014/kWh	$0.027/kWh	$0.039/kWh	$0.050/kWh	$0.060/kWh	$0.014/kWh
	3	$0.024/kWh	*$0.046/kWh* ~~$0.045/kWh~~	$0.066/kWh	*$0.086/kWh* ~~$0.085/kWh~~	*$0.103/kWh* ~~$0.102/kWh~~	$0.024/kWh
Large General Service Primary Demand Rate GPD	1	*$30/kW* ~~$25/kW~~	*$60/kW* ~~$45/kW~~	*$90/kW* ~~$70/kW~~	*$115/kW* ~~$90/kW~~	*$135/kW* ~~$105/kW~~	*$30/kW* ~~$25/kW~~
	2	*$45/kW* ~~$50/kW~~	*$90/kW* ~~$95/kW~~	*$130/kW* ~~$135/kW~~	*$170/kW* ~~$175/kW~~	*$205/kW* ~~$215/kW~~	*$45/kW* ~~$50/kW~~
	3	$75/kW	*$140/kW* ~~$150/kW~~	*$205kW* ~~$215/kW~~	*$260/kW* ~~$280/kW~~	*$315/kW* ~~$335/kW~~	$75/kW
General Service Primary Time-of-Use Rate GPTU	1	$0.008/kWh	*$0.016/kWh* ~~$0.015/kWh~~	*$0.023/kWh* ~~$0.022/kWh~~	*$0.029/kWh* ~~$0.028/kWh~~	*$0.035kWh* ~~$0.034/kWh~~	NA
	2	*$0.010/kWh* ~~$0.011/kWh~~	*$0.018/kWh* ~~$0.021/kWh~~	*$0.027/kWh* ~~$0.030/kWh~~	*$0.034/kWh* ~~$0.038/kWh~~	*$0.041/kWh* ~~$0.046/kWh~~	NA
	3	*$0.013/kWh* ~~$0.014/kWh~~	*$0.025/kWh* ~~$0.027/kWh~~	*$0.036/kWh* ~~$0.038/kWh~~	*$0.046/kWh* ~~$0.050/kWh~~	*$0.056/kWh* ~~$0.060/kWh~~	NA
Energy Intensive Primary Rate EIP	1	*$0.001/kWh* ~~$0.005/kWh~~	*$0.002/kWh* ~~$0.010/kWh~~	*$0.002/kWh* ~~$0.014/kWh~~	*$0.003/kWh* ~~$0.018/kWh~~	*$0.004/kWh* ~~$0.021/kWh~~	NA
	2	*$0.003/kWh* ~~$0.009/kWh~~	*$0.005/kWh* ~~$0.017/kWh~~	*$0.008/kWh* ~~$0.025/kWh~~	*$0.010/kWh* ~~$0.032/kWh~~	*$0.012/kWh* ~~$0.039/kWh~~	NA
	3	*$0.005/kWh* ~~$0.010/kWh~~	*$0.009/kWh* ~~$0.019/kWh~~	*$0.013/kWh* ~~$0.027/kWh~~	*$0.016/kWh* ~~$0.035/kWh~~	*$0.020/kWh* ~~$0.042/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)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 2

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-15.00**

(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:

$~~0.197458~~ *0.214650*	per kWh for all kWh during the months of June - September
$~~0.174375~~ *0.185856*	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)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 3

(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 ~~additional~~ cost resulting from the installation of the underground service connections. ~~Such~~ *For the route specified by the Company, the* contribution shall be *a flat fee of $1,300. 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 any additional costs in excess of those associated with the route specified by the Company* ~~computed on the basis of $4.50 per foot of required trench measured on the surface of the ground along the route of the cable from the secondary source to a point directly below the customer's meter(s)~~.

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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-23.00**

(Continued From Sheet No. C-22.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.3 Restoration of Service (Contd)

The restoration charge and meter relocation charge, if applicable, shall be billed to the customer and shall be paid before service is restored.

An On-Premises Site Visit Charge of $15.00 shall be assessed to the customer if a Company employee is sent to the premises to either serve the customer with a shut-off notification or to shut off service, unless the customer presents evidence that reasonably indicates the claim has been satisfied or is currently in dispute. The charge shall be applied to the customer account. The Company shall not assess this fee twice on the same notice for shutoff.

In case of shutoff of service, the Company shall restore service only after any metering changes, where deemed necessary by the Company, have been made by the Company and after the customer has paid for any unmetered energy used, paid for any damage to Company property, paid the restoration charge and meter relocation charge, installed any necessary devices to protect the Company's facilities and paid all charges as provided in the Company's Electric Rate Book.

A customer who orders a termination and a restoration of service at the same premises within a 12-month period shall be liable for a "turnon" charge of $11.

C5.4 Shutoff Protection Plan for Residential Customers

A. Eligibility

Eligible low-income customers and senior citizen customers may choose to participate in the Shutoff Protection Plan (SPP) in lieu of the applicable Winter Protection Plan as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.131, Winter Protection Plan for Eligible Low-Income Customers, or R 460.132, Winter Protection Plan for Eligible Senior Citizen Customers. For purposes of this Company rule, an eligible low-income customer means a utility customer who has not had more than one default condition on the SPP in the last twelve months and whose household income does not exceed ~~200~~*400*% of the federal poverty guidelines as published by the United States Department of Health and Human Services ~~or who receives supplemental security income or low-income assistance through the Department of Human Services or successor agency, food stamps, or Medicaid~~. In addition, an eligible senior citizen customer means a utility customer who has not had more than one default condition on the SPP in the last twelve months, is 65 years of age or older, and advises the utility of his or her eligibility. An eligible customer enrolled in the SPP shall be referred to as an SPP Customer. Customers may become eligible for a modified SPP as provided for in Rule C5.4. B.

(Continued on Sheet No. C-24.00)

See Byrom Testimony, Page 40, Lines 1-13; Exhibit A-96 (Gray-1), Item No. 5

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-24.00**

(Continued From Sheet No. C-23.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.4 Shutoff Protection Plan for Residential Customers (Contd)

B. Enrollment

An eligible customer may enroll at any time of the calendar year in the SPP. Where unauthorized use of utility service has not occurred, to enroll an eligible customer must (1) contact the Company and indicate that they wish to enroll, (2) be able to demonstrate that he or she has made application for state or federal heating assistance, or has a household income that does not exceed ~~200~~*400*% of the federal poverty guidelines as published by the United States Department of Health and Human Services ~~or receives supplemental security income or low-income assistance through the Department of Human Services or successor agency, food stamps, or Medicaid~~, (3) within 14 days of a customer calling to enroll in the SPP, have completed the enrollment process by paying a minimum down payment of 10% of the total amount owed to the Company at the time of the request to enroll. An eligible customer is not enrolled in the SPP until the enrollment requirements are fulfilled. Customers previously enrolled in the SPP the last twelve months who default may be permitted to re-enroll in a modified SPP payment arrangement, at the discretion of the Company, if they have demonstrated a willingness to satisfy the terms of the payment plan through their payment history or have received assistance that will improve the customer's ability to satisfy the payment arrangements. The modified SPP repayment period shall not exceed 24 months.

Customers who enroll in the SPP who have not been enrolled in the SPP for more than twelve months may not be required to pay a deposit or reconnection fee, if applicable. Customers who enroll in the SPP who were previously enrolled in the SPP in the last twelve months and removed due to default may be required to pay a deposit and a reconnection fee, if applicable.

Where unauthorized use of utility service has occurred, the customer must pay 100% of the portion of charges that are the result of the unauthorized use. Upon receipt of payment, the customer shall be considered eligible if all other eligibility requirements are met. The customer may then enroll under the conditions described previously. The payment of unauthorized use charges may be made at the same time as the down payment of the total amount owed to the Company is made. In the event that the downpayment of the total amount owed to the Company is made without payment of the unauthorized charges at the same time or previously, the payment received shall first be applied to the unauthorized charges.

In the event that an eligible customer has contacted the Company to indicate a wish to enroll but the requirements so described are not met in full, the eligible customer shall then be subject to credit action as though no contact with the Company had occurred. In the event that all Company obligations to shut off service have been met, the eligible customer shall receive a minimum of one communication at least 24 hours prior to shutoff of service.

C. Customer Protection

Once enrolled in the SPP, a utility shall not shut off service to a SPP Customer if the customer pays to the Company a monthly amount equal to 1/12th of the estimated annual bill for the SPP Customer and a Company-specified amount between 1/12th and 1/24th of any remaining delinquent balance owed to the Company at the time of the enrollment. The Company shall have the right to deny or shut off service in accordance with Rules and Regulations of the Company as authorized by the Michigan Public Service Commission outlined in Rule C1.3, Use of Service and in Rule C5.1, Access to Customer's Premises. While the customer is enrolled in the SPP and payments are made by the due date of the amount due shown on the bill, no late payment charges will be assessed. The SPP Customer may participate in the SPP for a maximum period of 24 months or until the delinquent charges are eliminated and the SPP Customer is able to pay his or her regular monthly energy bills.

(Continued on Sheet No. C-25.00)

See Byrom Testimony, Page 40, Lines 1-13; Exhibit A-96 (Gray-1), Item No. 5

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-25.00**

(Continued From Sheet No. C-24.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.4 Shutoff Protection Plan for Residential Customers (Contd)

C. Customer Protection (Contd)

The estimated annual bill for the SPP Customer and the delinquent balance due may be recalculated periodically by the Company. The Company may also recalculate the estimated annual bill and the delinquent balance due upon the transfer of a balance owed on another account in compliance with Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service.

D. Default

Should a SPP Customer fail to make payment by the due date, a shutoff notice specific to this SPP shall be issued but shall comply with the requirements of Part 8 of Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service. If the SPP Customer makes payment before the date provided for shutoff of service, the customer shall not be considered to be in default but shall remain in the SPP. If the SPP Customer makes payment after this date, the SPP Customer shall be in default and shall be removed from the SPP. The customer shall be subject to shutoff, provided the 24-hour notice was made by the Company.

E. Participation in Other Shutoff Protection Plans

Customers eligible to participate under the Winter Protection Plan, Rules R 460.131 and R 460.132, will be required to waive their rights to participate under the Winter Protection Plan in order to participate in the Plan. Upon enrollment, the Company shall send written confirmation of the enrollment terms and include notice of this provision.

C5.5 Non-Transmitting Meter Provision

Residential Customers electing a non-transmitting meter shall be served on Residential Service Secondary Non-Transmitting Meter Rate RSM. Non-Residential Customers served on General Service Secondary Rate GS have the option to choose a non-transmitting meter. In order for a customer to be eligible to participate in the Non-Transmitting Meter Provision, the customer must have a meter that is accessible to Company employees and the customer shall have zero instances of unauthorized use, theft, fraud and/or threats of violence toward Company employees.

Customers electing a non-transmitting meter will pay the following charges per premises or billing meter:

Up Front Charge:	~~$69.39~~	~~a one-time charge per billing meter per request if the notice is given before the transmitting meter is installed~~
	~~OR~~	
	$~~123.91~~ *216.22*	a one-time charge per billing meter per request ~~if the notice is given after the transmitting meter is installed~~
Monthly Charge:	$~~3.00~~ *3.09*	per month at each premises as defined in Rule B1., Technical Standards for Electric Service. Multiple metered units shall be charged per billing meter.

All standard charges and provisions of the customer's applicable tariff shall apply.

(Continued on Sheet No. C-26.00)

See Kelly Testimony, Page 188, Line 22 to Page 190, Line 28; Exhibit A-136 (MPK-26), Page 1

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-26.20**

(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 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 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. 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 any additional costs in excess of those associated with the route specified by the Company.

(Continued on Sheet No. C-27.00)

See Partlan Testimony, Page 12, Line 8 to Page 16, Line 9; Exhibit A-96 (Gray-1), Item No. 7

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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)

~~B.~~*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 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. 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 any additional costs in excess of those associated with the route specified by the Company.

~~C.~~*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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-28.00**

(Continued From Sheet No. C-27.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.1 Overhead Extension Policy (Contd)

~~C.~~ *E.* General (Contd)

(6) The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, amount of deposit and refunds thereon, minimum bills or other service conditions with respect to the customers or prospective customers whose load requirements exceed the capacity of the available distribution system in the area, or whose load characteristics or special service needs require unusual investments by the Company in Service Facilities or where there is not sufficient assurance of the permanence of the use of the service. The Company shall construct overhead electric distribution facilities and extensions only in the event it is able to obtain or use the necessary materials, equipment and supplies. The Company, subject only to review by the Commission, reserves the right, in its discretion, to allocate the use of such materials, equipment and supplies it may have on hand from time to time among the various classes of customers and prospective customers and among various customers and prospective customers of the same class.

(7) Contributions in Aid of Construction otherwise required by the Company may be suspended for charging sites participating in the PowerMIDrive Public or PowerMIFleet programs.

(8) All service rendered shall be subject to the Company's Standard Contract forms and to its Electric Rate Book.

(9) Any charges, deposits or contributions may be required In Advance of commencement of construction.

C6.2 Underground Policy

A. General

This rule sets forth the conditions under which the Company shall install direct burial underground electric distribution systems and underground service connections for residential and General Service customers. For the purpose of this rule, such underground distribution facilities are defined as those facilities operated at 15,000 Volts or less phase to ground wye connected or 20,000 Volts or less phase to phase delta connected.

The general policy of the Company is that real estate developers, property owners or other applicants for underground service shall make a contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between underground and equivalent overhead facilities.
Methods for determining this cost differential for specific classifications of service are provided herein. In cases, where the nature of service or the construction conditions are such that these conditions are not applicable, the general policy stated above shall apply.

In cases where the Company does not require underground electric distribution systems and/or underground service connections, but is required to underground such facilities by state or local law or regulation, the Company may adjust the contribution in aid of construction to account for such requirement.

It shall be mandatory that all original electric distribution systems installed in new residential subdivisions and in existing residential subdivisions in which overhead electric distribution facilities have not already been constructed be placed underground, except that a lot within a subdivision facing a previously existing street or county road and having an existing overhead distribution line on its side of the street or county road shall be served with an underground service from these facilities and shall be considered a part of the underground service area. It shall also be mandatory that all original service connections installed to serve one-family or two-family dwellings from an underground distribution system be placed underground.

Except as otherwise provided in the following paragraph, it shall be mandatory that all new General Service distribution systems and service connections installed in the vicinity of or on the customer's premises to be served, and constructed solely to serve the customer or a group of adjacent customers, be placed underground.

(Continued on Sheet No. C-29.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 7

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-31.00**

(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)

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 ~~additional~~ cost resulting from the installation of an underground service connection. For *the route specified by the Company,* ~~normal installations such~~ *the* contribution shall be ~~computed on the basis of~~ a flat fee of *$1,300* ~~$350.00 for the first 150 linear feet of service from the termination of the Company's facilities at the front or rear property line to a point directly below the customer's meter. Each additional foot of installation in excess of 150 linear feet shall be computed at $4.50 per linear foot. Where special routing of the service lateral is required by the customer, the $4.50 per foot charge will apply to the route of the line as installed~~. *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 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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-32.00**

(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 ~~additional~~ cost resulting from the installation of an underground service connection. *For the route specified by the Company,* ~~The required~~ *the* contribution shall be~~:~~ *a flat fee of $2,200. 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 any additional costs in excess of those associated with the route specified by the Company.*

~~(a) For apartment houses and condominiums, a rate of $6.50 per trench foot.~~

~~(b) For all other General Service customers a rate of $6.50 per trench foot.~~

(Continued on Sheet No. C-33.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-36.00**

(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 ~~1.07898~~ *1.07273* 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)

See Breuring Testimony Page 19, Lines 12-14; Exhibit A-52 (EMB-6), Line 57; Exhibit A-96 (Gray-1), Item No. 9

~~M.P.S.C. No. 14 - Electric~~
~~Consumers Energy Company~~ ~~Sheet No. C-50.00~~

~~(Continued from Sheet No. C-49.00)~~

~~C10. RENEWABLE ENERGY PLAN (REP) (Contd)~~

~~C10.4 Experimental Advanced Renewable Program Anaerobic Digestion Program (AD Program)~~

~~The purpose of this rule is to develop and test programs to enable the development of Michigan's renewable energy resources. The program is designed to purchase renewable energy from generators utilizing anaerobic digestion technology. The AD Program consists of approximately 2.4 MW.~~

~~A customer participating in the AD Program is required to install and operate an eligible generation system with alternating current capacity of no less than 150 kW and no more than 1.1 MW after serving the customer's usage. The Company reserves the right to extend, modify or terminate the experimental program.~~

~~A customer participating in the AD Program under this rate is not eligible to participate in the Company's Net Metering program with a system contracted to provide output to the Company under the AD Program. Customers with unsatisfactory payment history on their delivery account are not eligible to participate.~~

~~A. Eligible Equipment~~

~~To participate in the program, an individual or entity must own or lease an anaerobic digestion system capable of generating electricity through methane produced from waste that will qualify as a renewable energy resource as defined in 2008 PA 295. Landfill gas or other methane based units do not qualify for this program. The system must transmit all energy generated on the premises by such equipment not being used to serve the customer's load, to the Company's distribution system and sell such energy to the Company. The individual or applicant applying to participate shall be required to provide evidence of eligibility.~~

~~B. Distribution Requirements~~

~~(1) All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including any telecommunication links, if applicable). Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company.~~

~~(2) The Company will determine the particular nature of the voltage in each case. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.~~

~~(3) Energy and Demand Registering Meters are required for each generating unit served under this rate. For a customer with a secondary system in which the Company elects to measure the service on the primary side of any transformers, 3% shall be added for billing purposes from the energy measurements thus made. For a customer with a primary system in which the Company elects to measure the service on the secondary side of any transformers, 3% shall be deducted for billing purposes from the energy measurements thus made.~~

~~(Continued on Sheet No. C-51.00)~~

~~M.P.S.C. No. 14 - Electric~~
~~Consumers Energy Company~~ ~~Sheet No. C-51.00~~

~~(Continued from Sheet No. C-50.00)~~

~~C10. RENEWABLE ENERGY PLAN (REP) (Contd)~~

~~C10.4 Experimental Advanced Renewable Program Anaerobic Digestion Program (AD Program) (Contd)~~

~~B. Distribution Requirements (Contd)~~

~~(4) The customer must meet the Interconnection Standards referenced in Rule B8 of this Electric Rate Book, Interconnection and *Distributed Generation* Standards R 460.*911* - R 460.*992*, for the class of generator installed. Utility testing and approval of the interconnection and execution of a parallel operating agreement must be completed prior to the equipment operating in parallel with the distribution system of the utility.~~

~~(5) The customer is required to obtain the characteristics of service from the Company prior to the installation of equipment. The Company shall provide the characteristics in writing upon request. In the event that the equipment proposed for connection is not compatible with these characteristics, the Company shall have no obligation to modify its distribution system or provide any monetary compensation to the customer. The equipment shall be installed on the same premises to which energy is delivered to the customer, or on land contiguous to the premises to which energy is delivered to the customer that is owned by the customer or which the customer has a documented long-term lease in a format acceptable to the Company.~~

~~(6) Any service facilities shall be dedicated to the generator and the customer if applicable and shall not be shared with those providing service to any other customer. The Company shall determine the characteristics of service. Should the installation of new Company distribution facilities be necessary for the equipment, all costs for the distribution facilities installed may be charged to the applicant in advance of construction as a nonrefundable contribution.~~

~~(7) If, in the sole judgment of the Company, it appears that connection of the equipment and subsequent service through the Company's facilities may cause a safety hazard, endanger the Company facilities or the customer's equipment or to disturb the Company's service to other customers, the Company may refuse or delay connection of the equipment to its facilities.~~

~~C. Allocation~~

~~The Company will award contracts to participating customers through a formal solicitation beginning on April 1, 2014. If necessary to meet the program capacity, a second solicitation will be issued. Customers electing to participate in the AD Program are required to submit an application to the Company in accordance with a notice issued by the Company. Customers must also submit an application fee of $10 per kW capacity applied. The application fee is refundable for applications that are not selected. For customers selected to participate in the program, the application fee will be applied to any costs associated with modifications to the Company's distribution system to allow interconnection of the customer's generator. If there are no distribution modification costs required for interconnection, then the application fee will be applied to any other customer contribution required under the program and the net, if any, refunded back to the customer. In the event the application capacity exceeds the offered capacity, participants who have submitted valid applications will be selected through a random selection process. Application and information concerning the allocation process shall be made available by the Company at http://www.consumersenergy.com/EARP.~~

~~(1) A customer may only submit one application per solicitation for each location.~~

~~(Continued on Sheet No. C-52.00)~~

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	$~~(0.150563)~~	*(0.153790)*	per kWh of On-Peak Outflow between June 1 and September 30
On-Peak Basic	$~~(0.099222)~~	*(0.105260)*	per kWh of Off-Peak Outflow between June 1 and September 30
Rate RSP	$~~(0.085252)~~	*(0.084027)*	per kWh of all Outflow kWh between October 1 and May 31
	$~~(0.150563)~~	*(0.153790)*	per kWh of On-Peak Outflow between June 1 and September 30
Smart Hours	$~~(0.099222)~~	*(0.105260)*	per kWh of Off-Peak Outflow between June 1 and September 30
Rate RSH	$~~(0.095326)~~	*(0.097592)*	per kWh of On-Peak Outflow between October 1 and May 31
	$~~(0.082971)~~	*(0.081435)*	per kWh of Off-Peak Outflow between October 1 and May 31
	$~~(0.150563)~~	*(0.153790)*	per kWh of On-Peak Outflow between June 1 and September 30
Nighttime Savers	$~~(0.111465)~~	*(0.117603)*	per kWh of Off-Peak Outflow between June 1 and September 30
Rate RPM	$~~(0.082008)~~	*(0.095162)*	per kWh of Super Off-Peak Outflow between June 1 and September 30
	$~~(0.095326)~~	*(0.097592)*	per kWh of On-Peak Outflow between October 1 and May 31
	$~~(0.092809)~~	*(0.091545)*	per kWh of Off-Peak Outflow between October 1 and May 31
	$~~(0.071387)~~	*(0.073547)*	per kWh of Super Off-Peak Outflow between October 1 and May 31
Secondary Rates			
Rate GS	$~~(0.105382)~~	*(0.109330)*	per kWh of Outflow during the billing months of June - September
	$~~(0.082299)~~	*(0.080536)*	per kWh of Outflow during the billing months of October - May
Rate GSTU[(1)]	$~~(0.143964)~~	*(0.148743)*	per kWh of On-Peak Outflow during the billing months of June - September
	$~~(0.109833)~~	*(0.115845)*	per kWh of Mid-Peak Outflow during the billing months of June - September
	$~~(0.080255)~~	*(0.086918)*	per kWh of Off-Peak Outflow during the billing months of June - September
	$~~(0.090563)~~	*(0.087957)*	per kWh of On-Peak Outflow during the billing months of October - May
	$~~(0.070953)~~	*(0.071125)*	per kWh of Off-Peak Outflow during the billing months of October - May
Rate GSD[(1)]	$~~(0.033424)~~	*(0.032577)*	per kWh of Outflow during the billing months of June - September
	$~~(0.027323)~~	*(0.023899)*	per kWh of Outflow during the billing months of October - May
	$~~(27.63)~~	*(26.96)*	per kW of Outflow Demand during the billing months of June - September
	$~~(17.07)~~	*(18.05)*	per kW of Outflow Demand 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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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)

Primary Rates			
Rate GP			
Customer Voltage Level 1	~~$(0.093230)~~	*(0.096410)*	per kWh of outflow during the billing months of June - September
	~~$(0.072836)~~	*(0.071781)*	per kWh of outflow during the billing months of October - May
Customer Voltage Level 2	~~$(0.094425)~~	*(0.097643)*	per kWh of outflow during the billing months of June - September
	~~$(0.073764)~~	*(0.072701)*	per kWh of outflow during the billing months of October - May
Customer Voltage Level 3	~~$(0.095479)~~	*(0.098839)*	per kWh of outflow during the billing months of June - September
	~~$(0.074577)~~	*(0.073596)*	per kWh of outflow during the billing months of October - May
Rate GPD[2]			
Customer Voltage Level 1	~~$(0.042727)~~	*(0.040641)*	per kWh of On-Peak Outflow during the billing months of June - September
	~~$(0.027682)~~	*(0.026358)*	per kWh of Off-Peak Outflow during the billing months of June - September
	~~$(25.78)~~	*(25.78)*	per kW of Outflow Demand during the billing months of June - September
	~~$(0.029145)~~	*(0.025486)*	per kWh of On-Peak Outflow during the billing months of October - May
	~~$(0.025104)~~	*(0.022129)*	per kWh of Off-Peak Outflow during the billing months of October - May
	~~$(22.99)~~	*(23.17)*	per kW of Outflow Demand during the billing months of October - May
Customer Voltage Level 2	~~$(0.043240)~~	*(0.041117)*	per kWh of On-Peak Outflow during the billing months of June - September
	~~$(0.028014)~~	*(0.026666)*	per kWh of Off-Peak Outflow during the billing months of June - September
	$(26.12)		per kW of Outflow Demand during the billing months of June - September
	~~$(0.029495)~~	*(0.025784)*	per kWh of On-Peak Outflow during the billing months of October - May
	~~$(0.025405)~~	*(0.022388)*	per kWh of Off-Peak Outflow during the billing months of October - May
	~~$(23.29)~~	*(23.48)*	per kW of Outflow Demand during the billing months of October - May
Customer Voltage Level 3	~~$(0.043667)~~	*(0.041531)*	per kWh of On-Peak Outflow during the billing months of June - September
	~~$(0.028291)~~	*(0.026935)*	per kWh of Off-Peak Outflow during the billing months of June - September
	~~$(26.42)~~	*(26.46)*	per kW of Outflow Demand during the billing months of June - September
	~~$(0.029787)~~	*(0.026044)*	per kWh of On-Peak Outflow during the billing months of October - May
	~~$(0.025656)~~	*(0.022614)*	per kWh of Off-Peak Outflow during the billing months of October - May
	~~$(23.57)~~	*(23.80)*	per kW of Outflow Demand during the billing months of October - May
Rate GPTU			
Customer Voltage Level 1	~~$(0.129361)~~	*(0.125095)*	per kWh of High-Peak Outflow between June 1 and September 30
	~~$(0.114706)~~	*(0.111347)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	~~$(0.090449)~~	*(0.089906)*	per kWh of Low-Peak Outflow between June 1 and September 30
	~~$(0.067951)~~	*(0.067092)*	per kWh of Off-Peak Outflow between June 1 and September 30
	~~$(0.084662)~~	*(0.080562)*	per kWh of High-Peak Outflow between October 1 and May 31
	~~$(0.079992)~~	*(0.074652)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	~~$(0.067868)~~	*(0.062464)*	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 2	~~$(0.131005)~~	*(0.126691)*	per kWh of High-Peak Outflow between June 1 and September 30
	~~$(0.116169)~~	*(0.112768)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	~~$(0.091604)~~	*(0.091054)*	per kWh of Low-Peak Outflow between June 1 and September 30
	~~$(0.068813)~~	*(0.067949)*	per kWh of Off-Peak Outflow between June 1 and September 30
	~~$(0.085737)~~	*(0.081591)*	per kWh of High-Peak Outflow between October 1 and May 31
	~~$(0.081011)~~	*(0.075606)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	~~$(0.068733)~~	*(0.063261)*	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 3	~~$(0.132440)~~	*(0.128239)*	per kWh of High-Peak Outflow between June 1 and September 30
	~~$(0.117451)~~	*(0.114145)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	~~$(0.092617)~~	*(0.092165)*	per kWh of Low-Peak Outflow between June 1 and September 30
	~~$(0.069566)~~	*(0.068779)*	per kWh of Off-Peak Outflow between June 1 and September 30
	~~$(0.086674)~~	*(0.082587)*	per kWh of High-Peak Outflow between October 1 and May 31
	~~$(0.081901)~~	*(0.076528)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	~~$(0.069489)~~	*(0.064032)*	per kWh of Off-Peak Outflow between October 1 and May 31

[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.

(Continued on Sheet No. C-64.50)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-64.50**

(Continued from Sheet No. C-64.40)

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)

Rate EIP			
Customer Voltage Level 1	$~~(0.181549)~~	*(0.183885)*	per kWh of Critical Peak Outflow between June 1 and September 30
	$~~(0.121032)~~	*(0.122589)*	per kWh of High-Peak Outflow between June 1 and September 30
	$~~(0.107716)~~	*(0.109682)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	$~~(0.085436)~~	*(0.087567)*	per kWh of Low-Peak Outflow between June 1 and September 30
	$~~(0.063507)~~	*(0.064571)*	per kWh of Off-Peak Outflow between June 1 and September 30
	$~~(0.119141)~~	*(0.116006)*	per kWh of Critical Peak Outflow between October 1 and May 31
	$~~(0.079427)~~	*(0.077337)*	per kWh of High-Peak Outflow between October 1 and May 31
	$~~(0.074678)~~	*(0.072141)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	$~~(0.063616)~~	*(0.060448)*	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 2	$~~(0.183844)~~	*(0.186209)*	per kWh of Critical Peak Outflow between June 1 and September 30
	$~~(0.122563)~~	*(0.124140)*	per kWh of High-Peak Outflow between June 1 and September 30
	$~~(0.109085)~~	*(0.111068)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	$~~(0.086524)~~	*(0.088676)*	per kWh of Low-Peak Outflow between June 1 and September 30
	$~~(0.064309)~~	*(0.065390)*	per kWh of Off-Peak Outflow between June 1 and September 30
	$~~(0.120646)~~	*(0.117475)*	per kWh of Critical Peak Outflow between October 1 and May 31
	$~~(0.080431)~~	*(0.078317)*	per kWh of High-Peak Outflow between October 1 and May 31
	$~~(0.075624)~~	*(0.073053)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	$~~(0.064423)~~	*(0.061213)*	per kWh of Off-Peak Outflow between October 1 and May 31
Customer Voltage Level 3	$~~(0.185840)~~	*(0.188439)*	per kWh of Critical Peak Outflow between June 1 and September 30
	$~~(0.123893)~~	*(0.125626)*	per kWh of High-Peak Outflow between June 1 and September 30
	$~~(0.110280)~~	*(0.112396)*	per kWh of Mid-Peak Outflow between June 1 and September 30
	$~~(0.087475)~~	*(0.089738)*	per kWh of Low-Peak Outflow between June 1 and September 30
	$~~(0.065006)~~	*(0.066174)*	per kWh of Off-Peak Outflow between June 1 and September 30
	$~~(0.121955)~~	*(0.118887)*	per kWh of Critical Peak Outflow between October 1 and May 31
	$~~(0.081303)~~	*(0.079257)*	per kWh of High-Peak Outflow between October 1 and May 31
	$~~(0.076448)~~	*(0.073930)*	per kWh of Mid-Peak Outflow between October 1 and May 31
	$~~(0.065126)~~	*(0.061947)*	per kWh of Off-Peak Outflow between October 1 and May 31

b. Retail Open Access Customers

The Outflow Credit will be determined by the Retail Service Supplier

(Continued on Sheet No. C-64.60)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-77.00**

(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 ~~2.32~~*2.24*% for interconnection voltages less than 46 kV or ~~1.33~~*1.36*% 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**
2022	$0.02983	$0.02477	$0.02955	$0.02453
2023	$0.03076	$0.02553	$0.03048	$0.02529
2024	$0.03118	$0.02643	$0.03089	$0.02618
2025	$0.03145	$0.02646	$0.03116	$0.02621
2026	$0.03293	$0.02755	$0.03263	$0.02729
2027	$0.03455	$0.02863	$0.03423	$0.02836
2028	$0.03527	$0.02874	$0.03495	$0.02847
2029	$0.03621	$0.02973	$0.03588	$0.02945
2030	$0.03724	$0.03049	$0.03690	$0.03021
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 ~~2.32~~*2.24*% for interconnection voltages less than 46 kV or ~~1.33~~*1.36*% for interconnection voltage at 46 kV and less the Administrative Fee of $0.001/kWh.			

(Continued on Sheet No. C-78.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. C-78.00**

(Continued From Sheet No. C-77.00)

C18. STANDARD OFFER - PURCHASED POWER (Contd)

D. Renewable Energy Credits

Renewable Energy Credits (RECs) are owned by the seller. The Company may purchase RECs from sellers that are willing to sell RECs generated. The Company will enter into a separate agreement with the seller for the purchase of any RECs.

E. Term

For QFs at or below 150kW$_{AC}$ in size who qualify for the Standard Offer based on C18A (1) of this rule, the seller may select a contract length up to 20 years.

For QFs at or below 5MW$_{AC}$ in size who qualify for the Standard Offer based on C18A (2) of this rule, the seller may select to receive a contract length up to 15 years when selecting Rate Option 1, or up to 10 years when selecting Rate Option 2.

All Standard Offer PPAs shall require a minimum contract term of one (1) year, and ~~In~~*in* no event shall the term of any PPA as listed above expire prior to the end of a MISO planning period.

F. Early Termination

Sellers shall be required, based on the options made available by the Company, to select a form of security to cover the financial risk associated with the Company's cost for replacement supply in the event the QF ceases operation prior to the end of the term of the PPA.

Security shall be provided through a letter of credit, one-time escrow payment, or monthly escrow payments.
The amount of security required will be based on the contract capacity and the term of the contract. This early termination security amount will be calculated using the following table:

Contract Term (Years)	**Early Termination Security Amount**
5	$10,000 x Contract Capacity (MW)
10	$30,000 x Contract Capacity (MW)
15	$52,500 x Contract Capacity (MW)
20	$62,500 x Contract Capacity (MW)

G. Execution of Standard PPA

In order to execute the Standard PPA, the Seller must complete all of the general project information requested in the applicable Standard PPA. When all information required in the standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the Seller must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA. When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days.

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-~~21585~~ *21870*) Effective for service rendered on and after ~~April 4, 2025~~ *XXXXXX, XX 2026*
Rate RSP	$~~0.002250~~ *0.002227*/kWh
Rate RSH	~~0.002250~~ *0.002227*/kWh
Rate RPM	~~0.002250~~ *0.002227*/kWh
Rate RSM	~~0.002250~~ *0.002227*/kWh
Rate GS	~~0.002106~~ *0.002035*/kWh
Rate GSTU	~~0.002106~~ *0.002035*/kWh
Rate GSD	~~0.71~~ *0.68*/kW
Rate GP	
Customer Voltage Level 1	~~0.001786~~ *0.001726*/kWh
Customer Voltage Level 2	~~0.001807~~ *0.001746*/kWh
Customer Voltage Level 3	~~0.001825~~ *0.001764*/kWh
Rate GPD	
Customer Voltage Level 1	~~0.80~~ *0.74*/kW
Customer Voltage Level 2	~~0.81~~ *0.76*/kW
Customer Voltage Level 3	~~0.82~~ *0.77*/kW
Rate GPTU	
Customer Voltage Level 1	~~0.001608~~ *0.001531*/kWh
Customer Voltage Level 2	~~0.001628~~ *0.001549*/kWh
Customer Voltage Level 3	~~0.001644~~ *0.001564*/kWh
Rate EIP	
Customer Voltage Level 1	~~0.001365~~ *0.001276*/kWh
Customer Voltage Level 2	~~0.001382~~ *0.001291*/kWh
Customer Voltage Level 3	~~0.001395~~ *0.001304*/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	~~0.000518~~ *0.000518*/kWh
Rate GUL	~~0.000498~~ *0.000487*/kWh
Rate GUL-LED	~~0.000498~~ *0.000487*/kWh
Rate GU	~~0.001366~~ *0.001338*/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-21585) Effective for service rendered April 4, 2025 through February 28, 2026	*Investment Recovery Mechanism (IRM) (Case No. U-21870) Effective for service rendered XXXXXX XX, 2026 through April 30, 2027*
Rate RSP	$0.000259/kWh	*$0.001123/kWh*
Rate RSH	0.000259/kWh	*0.001123/kWh*
Rate RPM	0.000259/kWh	*0.001123/kWh*
Rate RSM	0.000259/kWh	*0.001123/kWh*
Rate GS	0.000211/kWh	*0.000858/kWh*
Rate GSTU	0.000211/kWh	*0.000858/kWh*
Rate GSD	0.000151/kWh	*0.000661/kWh*
Rate GP		
Customer Voltage Level 1	0.000013/kWh	*0.000107/kWh*
Customer Voltage Level 2	0.000043/kWh	*0.000164/kWh*
Customer Voltage Level 3	0.000076/kWh	*0.000280/kWh*
Rate GPD		
Customer Voltage Level 1	0.000009/kWh	*0.000072/kWh*
Customer Voltage Level 2	0.000029/kWh	*0.000111/kWh*
Customer Voltage Level 3	0.000051/kWh	*0.000188/kWh*
Rate GPTU		
Customer Voltage Level 1	0.000009/kWh	*0.000072/kWh*
Customer Voltage Level 2	0.000029/kWh	*0.000111/kWh*
Customer Voltage Level 3	0.000051/kWh	*0.000188/kWh*
Rate EIP		
Customer Voltage Level 1	0.000009/kWh	*0.000072/kWh*
Customer Voltage Level 2	0.000029/kWh	*0.000111/kWh*
Customer Voltage Level 3	0.000051/kWh	*0.000188/kWh*
Rate LED		
Customer Voltage Level 1	0.000009/kWh	*0.000072/kWh*
Customer Voltage Level 2	0.000029/kWh	*0.000111/kWh*
Customer Voltage Level 3	0.000051/kWh	*0.000188/kWh*
Rate LTILRR	NA	*NA*
Rate GSG-2		
Customer Voltage Level 1	0.000009/kWh	*0.000072/kWh*
Customer Voltage Level 2	0.000029/kWh	*0.000111/kWh*
Customer Voltage Level 3	0.000051/kWh	*0.000188/kWh*
Rate GML	0.000257/kWh	*0.001276/kWh*
Rate GUL	0.001028/kWh	*0.005501/kWh*
Rate GU-LED	0.001028/kWh	*0.005501/kWh*
Rate GU	0.000081/kWh	*0.000369/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*

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 13; Exhibit A-64 (LMC-7)

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-21585) Effective for service rendered April 4, 2025 through April 3, 2026	*Electric Rate Case Deferral Surcharge (Case No. U-21870) Effective for service rendered XXXXXX XX, 2026 through XXXXXX XX, 2027*
Rate RSP	$0.001090/kWh	*$0.001228/kWh*
Rate RSH	0.001090/kWh	*0.001228/kWh*
Rate RPM	0.001090/kWh	*0.001228/kWh*
Rate RSM	0.001090/kWh	*0.001228/kWh*
Rate GS	0.000889/kWh	*0.000938/kWh*
Rate GSTU	0.000889/kWh	*0.000938/kWh*
Rate GSD	0.000638/kWh	*0.000723/kWh*
Rate GP		
Customer Voltage Level 1	0.000055/kWh	*0.000117/kWh*
Customer Voltage Level 2	0.000183/kWh	*0.000180/kWh*
Customer Voltage Level 3	0.000319/kWh	*0.000306/kWh*
Rate GPD		
Customer Voltage Level 1	0.000037/kWh	*0.000079/kWh*
Customer Voltage Level 2	0.000123/kWh	*0.000121/kWh*
Customer Voltage Level 3	0.000214/kWh	*0.000207/kWh*
Rate GPTU		
Customer Voltage Level 1	0.000037/kWh	*0.000079/kWh*
Customer Voltage Level 2	0.000123/kWh	*0.000121/kWh*
Customer Voltage Level 3	0.000214/kWh	*0.000207/kWh*
Rate EIP		
Customer Voltage Level 1	0.000037/kWh	*0.000079/kWh*
Customer Voltage Level 2	0.000123/kWh	*0.000121/kWh*
Customer Voltage Level 3	0.000214/kWh	*0.000207/kWh*
Rate LED		
Customer Voltage Level 1	0.000037/kWh	*0.000079/kWh*
Customer Voltage Level 2	0.000123/kWh	*0.000121/kWh*
Customer Voltage Level 3	0.000214/kWh	*0.000207/kWh*
Rate LTILRR	NA	*NA*
Rate GSG-2		
Customer Voltage Level 1	0.000037/kWh	*0.000079/kWh*
Customer Voltage Level 2	0.000123/kWh	*0.000121/kWh*
Customer Voltage Level 3	0.000214/kWh	*0.000207/kWh*
Rate GML	0.001082/kWh	*0.001395/kWh*
Rate GUL	0.004333/kWh	*0.006016/kWh*
Rate GU-LED	0.004333/kWh	*0.006016/kWh*
Rate GU	0.000343/kWh	*0.000404/kWh*
Rate PA	NA	*NA*
Rate ROA-R	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*
Rate ROA-S	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*
Rate ROA-P	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*
Rate ROA-GPD	Same as Full Service Delivery Rate Schedule	*Same as Full Service Delivery Rate Schedule*

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 13; Exhibit A-67 (LMC-6)

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	
$0.088450	*$0.016810*	*$0.105260*	per kWh for Off-Peak kWh between June 1 and September 30
~~$0.091516~~	~~$0.007706~~	~~$0.099222~~	
$0.129230	*$0.024560*	*$0.153790*	per kWh for On-Peak kWh between June 1 and September 30
~~$0.139098~~	~~$0.011465~~	~~$0.150563~~	
$0.070608	*$0.013419*	*$0.084027*	per kWh for all kWh between October 1 and May 31
~~$0.079248~~	~~$0.006004~~	~~$0.085252~~	

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:	$~~0.078955~~ *0.100314*	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)	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:	$~~(30.00)~~ *(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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-17.00**

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:	$~~(1.00)~~ *(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:	$~~(0.007918)~~ *(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)

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 resale purposes or for any Non-Residential usage.

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	*$0.088450* ~~$0.091516~~	*$0.016810* ~~$0.007706~~	*$0.105260* ~~$0.099222~~	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	*$0.129230* ~~$0.139098~~	*$0.024560* ~~$0.011465~~	*$0.153790* ~~$0.150563~~	per kWh for all On-Peak kWh between June 1 and September 30
Off-Peak - Winter	*$0.068430* ~~$0.077159~~	*$0.013005* ~~$0.005812~~	*$0.081435* ~~$0.082971~~	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	*$0.082007* ~~$0.088715~~	*$0.015585* ~~$0.006611~~	*$0.097592* ~~$0.095326~~	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:	$~~0.078955~~ *0.100314*	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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Original Sheet No. D-36.10**

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)	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:	$~~(30.00)~~ *(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 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)

See Byrom Testimony, Page 25, Lines 12-20; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Page 2

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-38.00**

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:	$~~(1.00)~~ *(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:	$~~(0.007918)~~ *(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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-40.00**

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	*$0.079965* ~~$0.076716~~	*$0.015197* ~~$0.005292~~	*$0.095162* ~~$0.082008~~	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Summer	*$0.098822* ~~$0.102772~~	*$0.018781* ~~$0.008693~~	*$0.117603* ~~$0.111465~~	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	*$0.129230* ~~$0.139098~~	*$0.024560* ~~$0.011465~~	*$0.153790* ~~$0.150563~~	per kWh for all On-Peak kWh between June 1 and September 30
Super Off-Peak - Winter	*$0.061802* ~~$0.066802~~	*$0.011745* ~~$0.004585~~	*$0.073547* ~~$0.071387~~	per kWh for all Super Off-Peak kWh between October 1 and May 31
Off-Peak - Winter	*$0.076926* ~~$0.086417~~	*$0.014619* ~~$0.006392~~	*$0.091545* ~~$0.092809~~	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	*$0.082007* ~~$0.088715~~	*$0.015585* ~~$0.006611~~	*$0.097592* ~~$0.095326~~	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:	$~~0.078955~~ *0.100314*	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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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)	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:	$~~(30.00)~~ *(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)

See Byrom Testimony, Page 25, Lines 12-20; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Page 3

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-42.00**

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 $~~(1.00)~~ *(0.50)* per kWh of incremental energy reduction during a critical peak event

(Continued on Sheet No. D-43.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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	$~~(0.007918)~~ *(0.006373)*	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	
$0.070608 ~~$0.079248~~	*$0.013419* ~~$0.006004~~	*$0.084027* ~~$0.085252~~	per kWh for the first 600 kWh per month during the billing months of June - September
$0.129230 ~~$0.139098~~	*$0.024560* ~~$0.011465~~	*$0.153790* ~~$0.150563~~	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$0.070608 ~~$0.079248~~	*$0.013419* ~~$0.006004~~	*$0.084027* ~~$0.085252~~	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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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:	$~~0.078955~~ *0.100314*	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 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)	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:	$~~(30.00)~~ *(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)

See Byrom Testimony, Page 25, Lines 12-20; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Page 4

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	
$0.093281	*$0.016049*	*$0.109330*	per kWh for all kWh during the billing months of June - September
~~$0.097639~~	~~$0.007743~~	~~$0.105382~~	
$0.068639	*$0.011897*	*$0.080536*	per kWh for all kWh during the billing months of October - May
~~$0.076879~~	~~$0.005420~~	~~$0.082299~~	

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:	$~~0.063166~~ *0.074477*	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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-46.00**

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: $~~(0.000923)~~ *(0.001009)* 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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-48.00**

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 ~~any other Demand Response Program or~~ 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	*$0.074071* ~~$0.075218~~	*$0.012847* ~~$0.005037~~	*$0.086918* ~~$0.080255~~	per kWh for all Off-Peak kWh during the billing months of June - September
Mid-Peak-Summer	*$0.098737* ~~$0.102027~~	*$0.017108* ~~$0.007806~~	*$0.115845* ~~$0.109833~~	per kWh for all Mid-Peak kWh during the billing months of June - September
On-Peak-Summer	*$0.126776* ~~$0.134569~~	*$0.021967* ~~$0.009395~~	*$0.148743* ~~$0.143964~~	per kWh for all On-Peak kWh during the billing months of June - September
Off-Peak-Winter	*$0.060613* ~~$0.066563~~	*$0.010512* ~~$0.004390~~	*$0.071125* ~~$0.070953~~	per kWh for all Off-Peak kWh during the billing months of October - May
On-Peak -Winter	*$0.074942* ~~$0.084687~~	*$0.013015* ~~$0.005876~~	*$0.087957* ~~$0.090563~~	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:	$~~0.063166~~ *0.074477*	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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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: $~~(0.000923)~~ *(0.001009)* 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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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: $~~(0.021295)~~ *(0.021685)* 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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-51.00**

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	
$22.31	*$4.65*	*$26.96*	per kW for all kW of Peak Demand during the
~~$25.46~~	~~$2.17~~	~~$27.63~~	billing months of June - September
$13.91	*$4.14*	*$18.05*	per kW for all kW of Peak Demand during the
~~$15.14~~	~~$1.93~~	~~$17.07~~	billing months of October - May

Energy Charge:

Non-Capacity

$~~0.033424~~ *0.032577*	per kWh for all kWh during the billing months of June - September
$~~0.027323~~ *0.023899*	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:	$~~0.048648~~ *0.061544*	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:	$~~(0.000745)~~ *(0.000825)*	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	
$0.085845	*$0.012994*	*$0.098839*	per kWh for all kWh during the billing months of June - September
~~$0.089071~~	~~$0.006408~~	~~$0.095479~~	
$0.063684	*$0.009912*	*$0.073596*	per kWh for all kWh during the billing months of October - May
~~$0.070092~~	~~$0.004485~~	~~$0.074577~~	

Charges for Customer Voltage Level 2 (CVL2)
Energy Charge:

Non-Capacity	Capacity	Total	
$0.084852	*$0.012791*	*$0.097643*	per kWh for all kWh during the billing months of June - September
~~$0.088106~~	~~$0.006319~~	~~$0.094425~~	
$0.062944	*$0.009757*	*$0.072701*	per kWh for all kWh during the billing months of October - May
~~$0.069341~~	~~$0.004423~~	~~$0.073764~~	

Charges for Customer Voltage Level 1 (CVL1)
Energy Charge:

Non-Capacity	Capacity	Total	
$0.083803	*$0.012607*	*$0.096410*	per kWh for all kWh during the billing months of June - September
~~$0.087002~~	~~$0.006228~~	~~$0.093230~~	
$0.062165	*$0.009616*	*$0.071781*	per kWh for all kWh during the billing months of October - May
~~$0.068477~~	~~$0.004359~~	~~$0.072836~~	

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 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Pages 8-10

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-56.00**

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: $~~0.024779~~ *0.026035* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: $~~0.010731~~ *0.011747* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: $~~0.002918~~ *0.007451* 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 .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. 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 .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% 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 15% penalty will be applied to any metered-based charges, excluding surcharges, 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 15% 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 **Cancels Sixth Revised 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: $~~(0.001925)~~ *(0.004541)* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(0.001438)~~ *(0.004114)* 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: $~~(0.000558)~~*(0.000576)* 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	
$12.30	*$4.71*	*$17.01*	per kW of On-Peak Billing Demand during the billing
~~$15.31~~	~~$2.23~~	~~$17.54~~	months of June - September
$10.63	*$4.37*	*$15.00*	per kW of On-Peak Billing Demand during the billing
~~$13.23~~	~~$2.07~~	~~$15.30~~	months of October - May

Transmission Charge:

Non-Capacity

~~$8.88~~ *9.45*	per kW of On-Peak Billing Demand during the billing months of June - September
~~$8.27~~ *8.80*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity

~~$0.043667~~ *0.041531*	per kWh for all On-Peak kWh during the billing months of June - September
~~$0.028291~~ *0.026935*	per kWh for all Off-Peak kWh during the billing months of June - September
~~$0.029787~~ *0.026044*	per kWh for all On-Peak kWh during the billing months of October - May
~~$0.025656~~ *0.022614*	per kWh for all Off-Peak kWh during the billing months of October - May

(Continued on Sheet No. D-60.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Page 11-13

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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	
$12.18	*$4.64*	*$16.82*	per kW of On-Peak Billing Demand during the billing
~~$15.16~~	~~$2.20~~	~~$17.36~~	months of June - September
$10.52	*$4.30*	*$14.82*	per kW of On-Peak Billing Demand during the billing
~~$13.10~~	~~$2.04~~	~~$15.14~~	months of October - May

Transmission Charge:

Non-Capacity

$~~8.76~~ *9.30*	per kW of On-Peak Billing Demand during the billing months of June - September
$~~8.15~~ *8.66*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity

$~~0.043240~~ *0.041117*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.028014~~ *0.026666*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.029495~~ *0.025784*	per kWh for all On-Peak kWh during the billing months of October - May
$~~0.025405~~ *0.022388*	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	
$12.04	*$4.57*	*$16.61*	per kW of On-Peak Billing Demand during the billing
~~$14.98~~	~~$2.17~~	~~$17.15~~	months of June - September
$10.40	*$4.24*	*$14.64*	per kW of On-Peak Billing Demand during the billing
~~$12.94~~	~~$2.01~~	$14.95	months of October - May

Transmission Charge:

Non-Capacity

$~~8.63~~ *9.17*	per kW of On-Peak Billing Demand during the billing months of June - September
$~~8.04~~ *8.53*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity

$~~0.042727~~ *0.040641*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.027682~~ *0.026358*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.029145~~ *0.025486*	per kWh for all On-Peak kWh during the billing months of October - May
$~~0.025104~~ *0.022129*	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)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Page 11-13

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)
Capacity Charge: $~~7.02~~ *7.10* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)
Capacity Charge: $~~3.50~~ *3.84* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)
Capacity Charge: $~~1.02~~ *2.53* 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 .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. 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 .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% 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 15% penalty will be applied to any metered-based charges, excluding surcharges, 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 15% penalty applies again.

(Continued on Sheet No. D-62.00)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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: $~~(0.83)~~ *(1.94)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(0.66)~~ *(1.83)* 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. *Notwithstanding 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: $~~(0.000194)~~ *(0.000204)* 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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-66.00**

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: $~~0.032871~~ *0.034131* per kWh for all kWh during the billing months of June - September
$~~0.030146~~ *0.032201* 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: $~~0.031540~~ *0.032600* per kWh for all kWh during the billing months of June - September
$~~0.028315~~ *0.029537* 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: $~~0.029172~~ *0.030167* per kWh for all kWh during the billing months of June - September
$~~0.026113~~ *0.027326* 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%	~~1.004~~ *0.986*%
Customer Voltage Level 2	~~1.328~~ *1.359*%	~~2.296~~ *2.247*%
Customer Voltage Level 3	~~3.300~~ *3.268*%	~~7.407~~ *6.502*%

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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-67.10**

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	*$0.032328* ~~$0.032171~~	*$0.032328* ~~$0.032171~~	per kWh of On-Peak kWh during the billing months of June - September
NA	*$0.028498* ~~$0.027648~~	*$0.028498* ~~$0.027648~~	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
$12.30 ~~$15.31~~	*$4.71* ~~$2.23~~	*$17.01* ~~$17.54~~	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
$10.63 ~~$13.23~~	*$4.37* ~~$2.07~~	*$15.00* ~~$15.30~~	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	
$~~0.016289~~ *0.017954*	per kWh of On-Peak kWh during the billing months of June - September
$~~0.014945~~ *0.016714*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity	
$~~0.028291~~ *0.026935*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.043667~~ *0.041531*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.025656~~ *0.022614*	per kWh for all Off-Peak kWh during the billing months of October - May
$~~0.029787~~ *0.026044*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
$12.30 ~~$15.31~~	*$4.71* ~~$2.23~~	*$17.01* ~~$17.54~~	per kW of On-Peak Billing Demand during a System Integrity Event during the billing months of June - September
$10.63 ~~$13.23~~	*$4.37* ~~$2.07~~	*$15.00* ~~$15.30~~	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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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	*$0.031117* ~~$0.031076~~	*$0.031117* ~~$0.031076~~	per kWh of On-Peak kWh during the billing months of June - September
NA	*$0.027397* ~~$0.027142~~	*$0.027397* ~~$0.027142~~	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
$12.18 ~~$15.16~~	*$4.64* ~~$2.20~~	*$16.82* ~~$17.36~~	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
$10.52 ~~$13.10~~	*$4.30* ~~$2.04~~	*$14.82* ~~$15.14~~	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

~~$0.015679~~ *0.017210*	per kWh of On-Peak kWh during the billing months of June - September
~~$0.008036~~ *0.008455*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity

~~$0.028014~~ *0.026666*	per kWh for all Off-Peak kWh during the billing months of June - September
~~$0.043240~~ *0.041117*	per kWh for all On-Peak kWh during the billing months of June - September
~~$0.025405~~ *0.022388*	per kWh for all Off-Peak kWh during the billing months of October - May
~~$0.029495~~ *0.025784*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
$12.18 ~~$15.16~~	*$4.64* ~~$2.20~~	*$16.82* ~~$17.36~~	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of June - September
$10.52 ~~$13.10~~	*$4.30* ~~$2.04~~	*$14.82* ~~$15.14~~	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	*$0.029002* ~~$0.028949~~	*$0.029002* ~~$0.028949~~	per kWh of On-Peak kWh during the billing months of June - September
NA	*$0.025524* ~~$0.025209~~	*$0.025524* ~~$0.025209~~	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
$12.04 ~~$14.98~~	*$4.57* ~~$2.17~~	*$16.61* ~~$17.15~~	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
$10.40 ~~$12.94~~	*$4.24* ~~$2.01~~	*$14.64* ~~$14.95~~	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)

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)

Coincident Peak Demand Provision (CPD) (Contd)

Monthly Rate (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

$~~0.014572~~ *0.016007*	per kWh of On-Peak kWh during the billing months of June - September
$~~0.013548~~ *0.014879*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity

$~~0.027682~~ *0.026358*	per kWh for all Off-Peak kWh during the billing months of June - September
$~~0.042727~~ *0.040641*	per kWh for all On-Peak kWh during the billing months of June - September
$~~0.025104~~ *0.022129*	per kWh for all Off-Peak kWh during the billing months of October - May
$~~0.029145~~ *0.025486*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
$12.04 ~~$14.98~~	*$4.57* ~~$2.17~~	*$16.61* ~~$17.15~~	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of June - September
$10.40 ~~$12.94~~	*$4.24* ~~$2.01~~	*$14.64* ~~$14.95~~	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-68.00)

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	*$0.060095* ~~$0.065802~~	*$0.008684* ~~$0.003764~~	*$0.068779* ~~$0.069566~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.080555* ~~$0.087045~~	*$0.011610* ~~$0.005572~~	*$0.092165* ~~$0.092617~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.099739* ~~$0.110513~~	*$0.014406* ~~$0.006938~~	*$0.114145* ~~$0.117451~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.112059* ~~$0.125172~~	*$0.016180* ~~$0.007268~~	*$0.128239* ~~$0.132440~~	per kWh during the calendar months of June - September
Off-Peak - Winter	*$0.056004* ~~$0.065478~~	*$0.008028* ~~$0.004011~~	*$0.064032* ~~$0.069489~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.066878* ~~$0.077240~~	*$0.009650* ~~$0.004661~~	*$0.076528* ~~$0.081901~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.072164* ~~$0.082011~~	*$0.010423* ~~$0.004663~~	*$0.082587* ~~$0.086674~~	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 2 (CVL2)
Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.059401* ~~$0.065101~~	*$0.008548* ~~$0.003712~~	*$0.067949* ~~$0.068813~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.079625* ~~$0.086109~~	*$0.011429* ~~$0.005495~~	*$0.091054* ~~$0.091604~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.098587* ~~$0.109327~~	*$0.014181* ~~$0.006842~~	*$0.112768* ~~$0.116169~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.110764* ~~$0.123837~~	*$0.015927* ~~$0.007168~~	*$0.126691* ~~$0.131005~~	per kWh during the calendar months of June - September
Off-Peak - Winter	*$0.055358* ~~$0.064777~~	*$0.007903* ~~$0.003956~~	*$0.063261* ~~$0.068733~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.066106* ~~$0.076414~~	*$0.009500* ~~$0.004597~~	*$0.075606* ~~$0.081011~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.071330* ~~$0.081138~~	*$0.010261* ~~$0.004599~~	*$0.081591* ~~$0.085737~~	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 1 (CVL1)
Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	*$0.058667* ~~$0.064293~~	*$0.008425* ~~$0.003658~~	*$0.067092* ~~$0.067951~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.078642* ~~$0.085033~~	*$0.011264* ~~$0.005416~~	*$0.089906* ~~$0.090449~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.097370* ~~$0.107963~~	*$0.013977* ~~$0.006743~~	*$0.111347* ~~$0.114706~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.109397* ~~$0.122297~~	*$0.015698* ~~$0.007064~~	*$0.125095* ~~$0.129361~~	per kWh during the calendar months of June - September
Off-Peak - Winter	*$0.054675* ~~$0.063969~~	*$0.007789* ~~$0.003899~~	*$0.062464* ~~$0.067868~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.065289* ~~$0.075462~~	*$0.009363* ~~$0.004530~~	*$0.074652* ~~$0.079992~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.070449* ~~$0.080130~~	*$0.010113* ~~$0.004532~~	*$0.080562* ~~$0.084662~~	per kWh 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 (CVL3)		
Capacity Charge:	$~~7.02~~ *7.10*	per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)
Capacity Charge: $~~3.50~~ *3.84* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)
Capacity Charge: $~~1.02~~ *2.53* 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 .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-72.00)

See Gray Testimony, Page 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Pages 14-16

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 .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. 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 .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% 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 15% penalty will be applied to any metered-based charges, excluding surcharges, 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 15% 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: $~~(0.83)~~ *(1.94)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $~~(0.66)~~ *(1.83)* 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: $~~(0.000194)~~ *(0.000204)* 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	*$0.059461* ~~$0.062133~~	*$0.006713* ~~$0.002873~~	*$0.066174* ~~$0.065006~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.080762* ~~$0.082986~~	*$0.008976* ~~$0.004489~~	*$0.089738* ~~$0.087475~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.101259* ~~$0.104822~~	*$0.011137* ~~$0.005458~~	*$0.112396* ~~$0.110280~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.113117* ~~$0.118309~~	*$0.012509* ~~$0.005584~~	*$0.125626* ~~$0.123893~~	per kWh during the calendar months of June - September
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	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	*$0.055740* ~~$0.062001~~	*$0.006207* ~~$0.003125~~	*$0.061947* ~~$0.065126~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.066469* ~~$0.072882~~	*$0.007461* ~~$0.003566~~	*$0.073930* ~~$0.076448~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.071199* ~~$0.077688~~	*$0.008058* ~~$0.003615~~	*$0.079257* ~~$0.081303~~	per kWh during the calendar months of October - May
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	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	*$0.058781* ~~$0.061476~~	*$0.006609* ~~$0.002833~~	*$0.065390* ~~$0.064309~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.079840* ~~$0.082097~~	*$0.008836* ~~$0.004427~~	*$0.088676* ~~$0.086524~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.100105* ~~$0.103702~~	*$0.010963* ~~$0.005383~~	*$0.111068* ~~$0.109085~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.111826* ~~$0.117056~~	*$0.012314* ~~$0.005507~~	*$0.124140* ~~$0.122563~~	per kWh during the calendar months of June - September
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	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	*$0.055103* ~~$0.061341~~	*$0.006110* ~~$0.003082~~	*$0.061213* ~~$0.064423~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.065709* ~~$0.072107~~	*$0.007344* ~~$0.003517~~	*$0.073053* ~~$0.075624~~	per kWh during the calendar months of October - May

High-Peak - Winter	*$0.070384* ~~$0.076866~~	*$0.007933* ~~$0.003565~~	*$0.078317* ~~$0.080431~~	per kWh during the calendar months of October - May
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	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 7, Lines 5-8; Exhibit A-96 (Gray-1), Item No. 14; Exhibit A-16 (LMC-3), Pages 17-19

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-76.00**

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	*$0.058058* ~~$0.060715~~	*$0.006513* ~~$0.002792~~	*$0.064571* ~~$0.063507~~	per kWh during the calendar months of June - September
Low-Peak - Summer	*$0.078859* ~~$0.081073~~	*$0.008708* ~~$0.004363~~	*$0.087567* ~~$0.085436~~	per kWh during the calendar months of June - September
Mid-Peak - Summer	*$0.098876* ~~$0.102411~~	*$0.010806* ~~$0.005305~~	*$0.109682* ~~$0.107716~~	per kWh during the calendar months of June - September
High-Peak - Summer	*$0.110453* ~~$0.115605~~	*$0.012136* ~~$0.005427~~	*$0.122589* ~~$0.121032~~	per kWh during the calendar months of June - September
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	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	*$0.054426* ~~$0.060579~~	*$0.006022* ~~$0.003037~~	*$0.060448* ~~$0.063616~~	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.064902* ~~$0.071212~~	*$0.007239* ~~$0.003466~~	*$0.072141* ~~$0.074678~~	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.069519* ~~$0.075914~~	*$0.007818* ~~$0.003513~~	*$0.077337* ~~$0.079427~~	per kWh during the calendar months of October - May
Interruptible Credit	$0.000000	*$(0.008461)* ~~$(0.008476)~~	*$(0.008461)* ~~$(0.008476)~~	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: $~~7.02~~ *7.10* per kW of Maximum Demand

Charge for Customer Voltage Level 2 (CVL 2)
Capacity Charge: $~~3.50~~ *3.84* per kW of Maximum Demand

Charge for Customer Voltage Level 1 (CVL 1)
Capacity Charge: $~~1.02~~ *2.53* 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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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 .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. 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 .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% 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 15% penalty will be applied to any metered-based charges, excluding surcharges, 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 15% 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: $~~(0.83)~~ *(1.94)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $~~(0.66)~~ *(1.83)* 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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-78.20**

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	$~~10.94~~ *11.27*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$~~11.09~~ *11.43*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$~~11.26~~ *11.61*	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	
Voltage Level 1	~~3.23~~ *3.08*%
Voltage Level 2	~~4.68~~ *4.25*%
Voltage Level 3	~~6.27~~ *5.27*%

(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:	$~~1.02~~ *2.53*	per kW of Maximum Demand
Customer Voltage Level 2:	$~~3.50~~ *3.84*	per kW of Maximum Demand
Customer Voltage Level 3:	$~~7.02~~ *7.10*	per kW of Maximum Demand

The Distribution Charges for the Largea 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: $~~(0.83)~~ *(1.94)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $~~(0.66)~~ *(1.83)* 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 0.909, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is higher than 0.909, 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 0.909. 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 0.909, 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 0.909 in accordance with the following table:

Power Factor	***Penalty***
0.700 to 0.909	*$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 0.909, 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 12, Line 13 to Page 13, Line 7; Exhibit A-96 (Gray-1), Item Nos. 14 and 17

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-78.40**

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.30)

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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company Sheet No. D-80.00

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM – ANAEROBIC DIGESTION PROGRAM (AD Program)

Availability:

Subject to any restrictions and requirements of Rule C10.4, an individual or entity who is a delivery customer of the Company that generates electricity from an anaerobic digestion system owned or leased by the customer is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge:

Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company.

Option 1 - Sales of Energy to the Company:

$86.00 per MWh purchased by the Company payable to the customer

Option 2 - Sales of Energy to the Company:

Beginning in the year the system comes on line with an escalating payment each year for the length of the contract ($/MWh purchased by the Company payable to the customer):

2015 - $76.39	2021 - $82.12	2027 - $90.33	2033 - $98.79
2016 - 77.17	2022 - 84.08	2028 - 91.62	2034 - 100.27
2017 - 77.33	2023 - 85.39	2029 - 93.13	2035 - 101.77
2018 - 78.49	2024 - 86.53	2030 - 94.51	2036 - 103.29
2019 - 79.88	2025 - 87.75	2031 - 95.91	2037 - 104.83
2020 - 81.23	2026 - 88.99	2032 - 97.34	2038 - 106.39

Purchase of Energy from the Company for standby service:

Energy supplied to the customer by the Company shall be provided at the applicable full service standby rate for which the customer qualifies subject to applicable surcharges, Securitization Charges, Power Supply Cost Recovery (PSCR) Factor and other charges as approved by the Commission.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract. Customers choosing Option 1 for sales of energy to the Company shall require a 20 year contract term. Customers choosing Option 2 shall require a contract with a 10 year minimum term and a 20 year maximum term.

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-82.00**

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 ~~2.07~~ *2.12*% plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~1.004~~ *0.986*%
Customer Voltage Level 2	~~1.328~~ *1.359*%	~~2.296~~ *2.247*%
Customer Voltage Level 3	~~3.300~~ *3.268*%	~~7.407~~ *6.502*%

Delivery Standby Charges:

System Access Charge:	$100.00	per generator installation per month
Charges for Customer Voltage Level 3 (CVL 3)		
Capacity Charge:	$~~7.02~~ *7.10*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL 2)		
Capacity Charge:	$~~3.50~~ *3.84*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL 1)		
Capacity Charge:	$~~1.02~~ *2.53*	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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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 .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. 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 .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% 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 15% penalty will be applied to any metered-based charges, excluding surcharges, 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 15% 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: $~~(0.83)~~ *(1.94)* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $~~(0.66)~~ *(1.83)* 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: $~~(1.02)~~ *(2.53)* 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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-85.00**

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	
$0.045804	$0.000000	*$0.045804*	per kWh for all kWh
~~$0.050983~~		~~$0.050983~~	

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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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:	$~~0.087373~~ *0.124589*	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	
$0.022478 ~~$0.025020~~	$0.000000	*$0.022478* ~~$0.025020~~	per kWh for all kWh

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:	$~~0.066586~~ *0.094947*	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 C10.7., 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-90.10**

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 ~~April 4, 2025~~ *XXXXXX XX, 2026*:
Company-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.33~~ *0.29*	$0.00	$~~0.33~~ *0.29*	$~~9.67~~ *10.47*	$~~10.00~~ *10.76*
25-34	$~~0.49~~ *0.43*	$0.00	$~~0.49~~ *0.43*	$~~10.19~~ *11.26*	$~~10.68~~ *11.69*
35-44	$~~0.66~~ *0.58*	$0.00	$~~0.66~~ *0.58*	$~~10.71~~ *12.06*	$~~11.37~~ *12.64*
45-54	$~~0.83~~ *0.72*	$0.00	$~~0.83~~ *0.72*	$~~11.23~~ *12.86*	$~~12.06~~ *13.58*
55-64	$~~1.00~~ *0.87*	$0.00	$~~1.00~~ *0.87*	$~~11.75~~ *13.66*	$~~12.75~~ *14.53*
65-74	$~~1.16~~ *1.02*	$0.00	$~~1.16~~ *1.02*	$~~12.27~~ *14.46*	$~~13.43~~ *15.48*
75-84	$~~1.33~~ *1.16*	$0.00	$~~1.33~~ *1.16*	$~~12.79~~ *15.25*	$~~14.12~~ *16.41*
85-94	$~~1.50~~ *1.31*	$0.00	$~~1.50~~ *1.31*	$~~13.31~~ *16.05*	$~~14.81~~ *17.36*
95-104	$~~1.66~~ *1.46*	$0.00	$~~1.66~~ *1.46*	$~~13.83~~ *16.85*	$~~15.49~~ *18.31*
105-114	$~~1.83~~ *1.60*	$0.00	$~~1.83~~ *1.60*	$~~14.35~~ *17.65*	$~~16.18~~ *19.25*
115-124	$~~2.00~~ *1.75*	$0.00	$~~2.00~~ *1.75*	$~~14.87~~ *18.45*	$~~16.87~~ *20.20*
125-134	$~~2.17~~ *1.90*	$0.00	$~~2.17~~ *1.90*	$~~15.38~~ *19.24*	$~~17.55~~ *21.14*
135-144	$~~2.33~~ *2.04*	$0.00	$~~2.33~~ *2.04*	$~~15.90~~ *20.04*	$~~18.23~~ *22.08*
145-154	$~~2.50~~ *2.19*	$0.00	$~~2.50~~ *2.19*	$~~16.42~~ *20.84*	$~~18.92~~ *23.03*
155-164	$~~2.67~~ *2.34*	$0.00	$~~2.67~~ *2.34*	$~~16.94~~ *21.64*	$~~19.61~~ *23.98*
165-174	$~~2.83~~ *2.48*	$0.00	$~~2.83~~ *2.48*	$~~17.46~~ *22.44*	$~~20.29~~ *24.92*
175-184	$~~3.00~~ *2.63*	$0.00	$~~3.00~~ *2.63*	$~~17.98~~ *23.23*	$~~20.98~~ *25.86*
185-194	$~~3.17~~ *2.78*	$0.00	$~~3.17~~ *2.78*	$~~18.50~~ *24.03*	$~~21.67~~ *26.81*
195-204	$~~3.34~~ *2.92*	$0.00	$~~3.34~~ *2.92*	$~~19.02~~ *24.83*	$~~22.36~~ *27.75*
205-214	$~~3.50~~ *3.07*	$0.00	$~~3.50~~ *3.07*	$~~19.54~~ *25.63*	$~~23.04~~ *28.70*
215-224	$~~3.67~~ *3.21*	$0.00	$~~3.67~~ *3.21*	$~~20.06~~ *26.43*	$~~23.73~~ *29.64*
225-234	$~~3.84~~ *3.36*	$0.00	$~~3.84~~ *3.36*	$~~20.58~~ *27.22*	$~~24.42~~ *30.58*
235-244	$~~4.01~~ *3.51*	$0.00	$~~4.01~~ *3.51*	$~~21.10~~ *28.02*	$~~25.11~~ *31.53*
245-254	$~~4.17~~ *3.65*	$0.00	$~~4.17~~ *3.65*	$~~21.62~~ *28.82*	$~~25.79~~ *32.47*
255-264	$~~4.34~~ *3.80*	$0.00	$~~4.34~~ *3.80*	$~~22.13~~ *29.62*	$~~26.47~~ *33.42*
265-274	$~~4.51~~ *3.95*	$0.00	$~~4.51~~ *3.95*	$~~22.65~~ *30.42*	$~~27.16~~ *34.37*
275-284	$~~4.67~~ *4.09*	$0.00	$~~4.67~~ *4.09*	$~~23.17~~ *31.22*	$~~27.84~~ *35.31*
285-294	$~~4.84~~ *4.24*	$0.00	$~~4.84~~ *4.24*	$~~23.69~~ *32.01*	$~~28.53~~ *36.25*
295-304	$~~5.01~~ *4.39*	$0.00	$~~5.01~~ *4.39*	$~~24.21~~ *32.81*	$~~29.22~~ *37.20*
305-314	$~~5.18~~ *4.53*	$0.00	$~~5.18~~ *4.53*	$~~24.73~~ *33.61*	$~~29.91~~ *38.14*
315-324	$~~5.34~~ *4.68*	$0.00	$~~5.34~~ *4.68*	$~~25.25~~ *34.41*	$~~30.59~~ *39.09*
325-334	$~~5.51~~ *4.83*	$0.00	$~~5.51~~ *4.83*	$~~25.77~~ *35.21*	$~~31.28~~ *40.04*
335-344	$~~5.68~~ *4.97*	$0.00	$~~5.68~~ *4.97*	$~~26.29~~ *36.00*	$~~31.97~~ *40.97*
345-354	$~~5.84~~ *5.12*	$0.00	$~~5.84~~ *5.12*	$~~26.81~~ *36.80*	$~~32.65~~ *41.92*
355-364	$~~6.01~~ *5.26*	$0.00	$~~6.01~~ *5.26*	$~~27.33~~ *37.60*	$~~33.34~~ *42.86*
365-374	$~~6.18~~ *5.41*	$0.00	$~~6.18~~ *5.41*	$~~27.85~~ *38.40*	$~~34.03~~ *43.81*
375-384	$~~6.35~~ *5.56*	$0.00	$~~6.35~~ *5.56*	$~~28.37~~ *39.20*	$~~34.72~~ *44.76*
385-394	$~~6.51~~ *5.70*	$0.00	$~~6.51~~ *5.70*	$~~28.89~~ *39.99*	$~~35.40~~ *45.69*
395-404	$~~6.68~~ *5.85*	$0.00	$~~6.68~~ *5.85*	$~~29.40~~ *40.79*	$~~36.08~~ *46.64*
405-414	$~~6.85~~ *6.00*	$0.00	$~~6.85~~ *6.00*	$~~29.92~~ *41.59*	$~~36.77~~ *47.59*
415-424	$~~7.02~~ *6.14*	$0.00	$~~7.02~~ *6.14*	$~~30.44~~ *42.39*	$~~37.46~~ *48.53*
425-434	$~~7.18~~ *6.29*	$0.00	$~~7.18~~ *6.29*	$~~30.96~~ *43.19*	$~~38.14~~ *49.48*
435-444	$~~7.35~~ *6.44*	$0.00	$~~7.35~~ *6.44*	$~~31.48~~ *43.98*	$~~38.83~~ *50.42*
445-454	$~~7.52~~ *6.58*	$0.00	$~~7.52~~ *6.58*	$~~32.00~~ *44.78*	$~~39.52~~ *51.36*
455-464	$~~7.68~~ *6.73*	$0.00	$~~7.68~~ *6.73*	$~~32.52~~ *45.58*	$~~40.20~~ *52.31*
465-474	$~~7.85~~ *6.88*	$0.00	$~~7.85~~ *6.88*	$~~33.04~~ *46.38*	$~~40.89~~ *53.26*
475-484	$~~8.02~~ *7.02*	$0.00	$~~8.02~~ *7.02*	$~~33.56~~ *47.18*	$~~41.58~~ *54.20*

(Continued on Sheet No. D-90.20)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **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 ~~April 4, 2025~~ *XXXXXX XX, 2026*:

Customer-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.33~~ *0.29*	$0.00	$~~0.33~~ *0.29*	$~~6.67~~ *7.47*	$~~7.00~~ *7.76*
25-34	$~~0.49~~ *0.43*	$0.00	$~~0.49~~ *0.43*	$~~7.19~~ *8.26*	$~~7.68~~ *8.69*
35-44	$~~0.66~~ *0.58*	$0.00	$~~0.66~~ *0.58*	$~~7.71~~ *9.06*	$~~8.37~~ *9.64*
45-54	$~~0.83~~ *0.72*	$0.00	$~~0.83~~ *0.72*	$~~8.23~~ *9.86*	$~~9.06~~ *10.58*
55-64	$~~1.00~~ *0.87*	$0.00	$~~1.00~~ *0.87*	$~~8.75~~ *10.66*	$~~9.75~~ *11.53*
65-74	$~~1.16~~ *1.02*	$0.00	$~~1.16~~ *1.02*	$~~9.27~~ *11.46*	$~~10.43~~ *12.48*
75-84	$~~1.33~~ *1.16*	$0.00	$~~1.33~~ *1.16*	$~~9.79~~ *12.25*	$~~11.12~~ *13.41*
85-94	$~~1.50~~ *1.31*	$0.00	$~~1.50~~ *1.31*	$~~10.31~~ *13.05*	$~~11.81~~ *14.36*
95-104	$~~1.66~~ *1.46*	$0.00	$~~1.66~~ *1.46*	$~~10.83~~ *13.85*	$~~12.49~~ *15.31*
105-114	$~~1.83~~ *1.60*	$0.00	$~~1.83~~ *1.60*	$~~11.35~~ *14.65*	$~~13.18~~ *16.25*
115-124	$~~2.00~~ *1.75*	$0.00	$~~2.00~~ *1.75*	$~~11.87~~ *15.45*	$~~13.87~~ *17.20*
125-134	$~~2.17~~ *1.90*	$0.00	$~~2.17~~ *1.90*	$~~12.38~~ *16.24*	$~~14.55~~ *18.14*
135-144	$~~2.33~~ *2.04*	$0.00	$~~2.33~~ *2.04*	$~~12.90~~ *17.04*	$~~15.23~~ *19.08*
145-154	$~~2.50~~ *2.19*	$0.00	$~~2.50~~ *2.19*	$~~13.42~~ *17.84*	$~~15.92~~ *20.03*
155-164	$~~2.67~~ *2.34*	$0.00	$~~2.67~~ *2.34*	$~~13.94~~ *18.64*	$~~16.61~~ *20.98*
165-174	$~~2.83~~ *2.48*	$0.00	$~~2.83~~ *2.48*	$~~14.46~~ *19.44*	$~~17.29~~ *21.92*
175-184	$~~3.00~~ *2.63*	$0.00	$~~3.00~~ *2.63*	$~~14.98~~ *20.23*	$~~17.98~~ *22.86*
185-194	$~~3.17~~ *2.78*	$0.00	$~~3.17~~ *2.78*	$~~15.50~~ *21.03*	$~~18.67~~ *23.81*
195-204	$~~3.34~~ *2.92*	$0.00	$~~3.34~~ *2.92*	$~~16.02~~ *21.83*	$~~19.36~~ *24.75*
205-214	$~~3.50~~ *3.07*	$0.00	$~~3.50~~ *3.07*	$~~16.54~~ *22.63*	$~~20.04~~ *25.70*
215-224	$~~3.67~~ *3.21*	$0.00	$~~3.67~~ *3.21*	$~~17.06~~ *23.43*	$~~20.73~~ *26.64*
225-234	$~~3.84~~ *3.36*	$0.00	$~~3.84~~ *3.36*	$~~17.58~~ *24.22*	$~~21.42~~ *27.58*
235-244	$~~4.01~~ *3.51*	$0.00	$~~4.01~~ *3.51*	$~~18.10~~ *25.02*	$~~22.11~~ *28.53*
245-254	$~~4.17~~ *3.65*	$0.00	$~~4.17~~ *3.65*	$~~18.62~~ *25.82*	$~~22.79~~ *29.47*
255-264	$~~4.34~~ *3.80*	$0.00	$~~4.34~~ *3.80*	$~~19.13~~ *26.62*	$~~23.47~~ *30.42*
265-274	$~~4.51~~ *3.95*	$0.00	$~~4.51~~ *3.95*	$~~19.65~~ *27.42*	$~~24.16~~ *31.37*
275-284	$~~4.67~~ *4.09*	$0.00	$~~4.67~~ *4.09*	$~~20.17~~ *28.22*	$~~24.84~~ *32.31*
285-294	$~~4.84~~ *4.24*	$0.00	$~~4.84~~ *4.24*	$~~20.69~~ *29.01*	$~~25.53~~ *33.25*
295-304	$~~5.01~~ *4.39*	$0.00	$~~5.01~~ *4.39*	$~~21.21~~ *29.81*	$~~26.22~~ *34.20*
305-314	$~~5.18~~ *4.53*	$0.00	$~~5.18~~ *4.53*	$~~21.73~~ *30.61*	$~~26.91~~ *35.14*
315-324	$~~5.34~~ *4.68*	$0.00	$~~5.34~~ *4.68*	$~~22.25~~ *31.41*	$~~27.59~~ *36.09*
325-334	$~~5.51~~ *4.83*	$0.00	$~~5.51~~ *4.83*	$~~22.77~~ *32.21*	$~~28.28~~ *37.04*
335-344	$~~5.68~~ *4.97*	$0.00	$~~5.68~~ *4.97*	$~~23.29~~ *33.00*	$~~28.97~~ *37.97*
345-354	$~~5.84~~ *5.12*	$0.00	$~~5.84~~ *5.12*	$~~23.81~~ *33.80*	$~~29.65~~ *38.92*
355-364	$~~6.01~~ *5.26*	$0.00	$~~6.01~~ *5.26*	$~~24.33~~ *34.60*	$~~30.34~~ *39.86*
365-374	$~~6.18~~ *5.41*	$0.00	$~~6.18~~ *5.41*	$~~24.85~~ *35.40*	$~~31.03~~ *40.81*
375-384	$~~6.35~~ *5.56*	$0.00	$~~6.35~~ *5.56*	$~~25.37~~ *36.20*	$~~31.72~~ *41.76*
385-394	$~~6.51~~ *5.70*	$0.00	$~~6.51~~ *5.70*	$~~25.89~~ *36.99*	$~~32.40~~ *42.69*
395-404	$~~6.68~~ *5.85*	$0.00	$~~6.68~~ *5.85*	$~~26.40~~ *37.79*	$~~33.08~~ *43.64*
405-414	$~~6.85~~ *6.00*	$0.00	$~~6.85~~ *6.00*	$~~26.92~~ *38.59*	$~~33.77~~ *44.59*
415-424	$~~7.02~~ *6.14*	$0.00	$~~7.02~~ *6.14*	$~~27.44~~ *39.39*	$~~34.46~~ *45.53*
425-434	$~~7.18~~ *6.29*	$0.00	$~~7.18~~ *6.29*	$~~27.96~~ *40.19*	$~~35.14~~ *46.48*
435-444	$~~7.35~~ *6.44*	$0.00	$~~7.35~~ *6.44*	$~~28.48~~ *40.98*	$~~35.83~~ *47.42*
445-454	$~~7.52~~ *6.58*	$0.00	$~~7.52~~ *6.58*	$~~29.00~~ *41.78*	$~~36.52~~ *48.36*
455-464	$~~7.68~~ *6.73*	$0.00	$~~7.68~~ *6.73*	$~~29.52~~ *42.58*	$~~37.20~~ *49.31*
465-474	$~~7.85~~ *6.88*	$0.00	$~~7.85~~ *6.88*	$~~30.04~~ *43.38*	$~~37.89~~ *50.26*
475-484	$~~8.02~~ *7.02*	$0.00	$~~8.02~~ *7.02*	$~~30.56~~ *44.18*	$~~38.58~~ *51.20*

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: $~~(6.91)~~ *(7.91)* 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 ~~April 4, 2025~~ *XXXXXX XX, 2026*:

Company-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.33~~ *0.29*	$0.00	$~~0.33~~ *0.29*	$~~9.67~~ *10.47*	$~~10.00~~ *10.76*
25-34	$~~0.49~~ *0.43*	$0.00	$~~0.49~~ *0.43*	$~~10.19~~ *11.26*	$~~10.68~~ *11.69*
35-44	$~~0.66~~ *0.58*	$0.00	$~~0.66~~ *0.58*	$~~10.71~~ *12.06*	$~~11.37~~ *12.64*
45-54	$~~0.83~~ *0.72*	$0.00	$~~0.83~~ *0.72*	$~~11.23~~ *12.86*	$~~12.06~~ *13.58*
55-64	$~~1.00~~ *0.87*	$0.00	$~~1.00~~ *0.87*	$~~11.75~~ *13.66*	$~~12.75~~ *14.53*
65-74	$~~1.16~~ *1.02*	$0.00	$~~1.16~~ *1.02*	$~~12.27~~ *14.46*	$~~13.43~~ *15.48*
75-84	$~~1.33~~ *1.16*	$0.00	$~~1.33~~ *1.16*	$~~12.79~~ *15.25*	$~~14.12~~ *16.41*
85-94	$~~1.50~~ *1.31*	$0.00	$~~1.50~~ *1.31*	$~~13.31~~ *16.05*	$~~14.81~~ *17.36*
95-104	$~~1.66~~ *1.46*	$0.00	$~~1.66~~ *1.46*	$~~13.83~~ *16.85*	$~~15.49~~ *18.31*
105-114	$~~1.83~~ *1.60*	$0.00	$~~1.83~~ *1.60*	$~~14.35~~ *17.65*	$~~16.18~~ *19.25*
115-124	$~~2.00~~ *1.75*	$0.00	$~~2.00~~ *1.75*	$~~14.87~~ *18.45*	$~~16.87~~ *20.20*
125-134	$~~2.17~~ *1.90*	$0.00	$~~2.17~~ *1.90*	$~~15.38~~ *19.24*	$~~17.55~~ *21.14*
135-144	$~~2.33~~ *2.04*	$0.00	$~~2.33~~ *2.04*	$~~15.90~~ *20.04*	$~~18.23~~ *22.08*
145-154	$~~2.50~~ *2.19*	$0.00	$~~2.50~~ *2.19*	$~~16.42~~ *20.84*	$~~18.92~~ *23.03*
155-164	$~~2.67~~ *2.34*	$0.00	$~~2.67~~ *2.34*	$~~16.94~~ *21.64*	$~~19.61~~ *23.98*
165-174	$~~2.83~~ *2.48*	$0.00	$~~2.83~~ *2.48*	$~~17.46~~ *22.44*	$~~20.29~~ *24.92*
175-184	$~~3.00~~ *2.63*	$0.00	$~~3.00~~ *2.63*	$~~17.98~~ *23.23*	$~~20.98~~ *25.86*
185-194	$~~3.17~~ *2.78*	$0.00	$~~3.17~~ *2.78*	$~~18.50~~ *24.03*	$~~21.67~~ *26.81*
195-204	$~~3.34~~ *2.92*	$0.00	$~~3.34~~ *2.92*	$~~19.02~~ *24.83*	$~~22.36~~ *27.75*
205-214	$~~3.50~~ *3.07*	$0.00	$~~3.50~~ *3.07*	$~~19.54~~ *25.63*	$~~23.04~~ *28.70*
215-224	$~~3.67~~ *3.21*	$0.00	$~~3.67~~ *3.21*	$~~20.06~~ *26.43*	$~~23.73~~ *29.64*
225-234	$~~3.84~~ *3.36*	$0.00	$~~3.84~~ *3.36*	$~~20.58~~ *27.22*	$~~24.42~~ *30.58*
235-244	$~~4.01~~ *3.51*	$0.00	$~~4.01~~ *3.51*	$~~21.10~~ *28.02*	$~~25.11~~ *31.53*
245-254	$~~4.17~~ *3.65*	$0.00	$~~4.17~~ *3.65*	$~~21.62~~ *28.82*	$~~25.79~~ *32.47*
255-264	$~~4.34~~ *3.80*	$0.00	$~~4.34~~ *3.80*	$~~22.13~~ *29.62*	$~~26.47~~ *33.42*
265-274	$~~4.51~~ *3.95*	$0.00	$~~4.51~~ *3.95*	$~~22.65~~ *30.42*	$~~27.16~~ *34.37*
275-284	$~~4.67~~ *4.09*	$0.00	$~~4.67~~ *4.09*	$~~23.17~~ *31.22*	$~~27.84~~ *35.31*
285-294	$~~4.84~~ *4.24*	$0.00	$~~4.84~~ *4.24*	$~~23.69~~ *32.01*	$~~28.53~~ *36.25*
295-304	$~~5.01~~ *4.39*	$0.00	$~~5.01~~ *4.39*	$~~24.21~~ *32.81*	$~~29.22~~ *37.20*
305-314	$~~5.18~~ *4.53*	$0.00	$~~5.18~~ *4.53*	$~~24.73~~ *33.61*	$~~29.91~~ *38.14*
315-324	$~~5.34~~ *4.68*	$0.00	$~~5.34~~ *4.68*	$~~25.25~~ *34.41*	$~~30.59~~ *39.09*
325-334	$~~5.51~~ *4.83*	$0.00	$~~5.51~~ *4.83*	$~~25.77~~ *35.21*	$~~31.28~~ *40.04*
335-344	$~~5.68~~ *4.97*	$0.00	$~~5.68~~ *4.97*	$~~26.29~~ *36.00*	$~~31.97~~ *40.97*
345-354	$~~5.84~~ *5.12*	$0.00	$~~5.84~~ *5.12*	$~~26.81~~ *36.80*	$~~32.65~~ *41.92*
355-364	$~~6.01~~ *5.26*	$0.00	$~~6.01~~ *5.26*	$~~27.33~~ *37.60*	$~~33.34~~ *42.86*
365-374	$~~6.18~~ *5.41*	$0.00	$~~6.18~~ *5.41*	$~~27.85~~ *38.40*	$~~34.03~~ *43.81*
375-384	$~~6.35~~ *5.56*	$0.00	$~~6.35~~ *5.56*	$~~28.37~~ *39.20*	$~~34.72~~ *44.76*
385-394	$~~6.51~~ *5.70*	$0.00	$~~6.51~~ *5.70*	$~~28.89~~ *39.99*	$~~35.40~~ *45.69*
395-404	$~~6.68~~ *5.85*	$0.00	$~~6.68~~ *5.85*	$~~29.40~~ *40.79*	$~~36.08~~ *46.64*
405-414	$~~6.85~~ *6.00*	$0.00	$~~6.85~~ *6.00*	$~~29.92~~ *41.59*	$~~36.77~~ *47.59*
415-424	$~~7.02~~ *6.14*	$0.00	$~~7.02~~ *6.14*	$~~30.44~~ *42.39*	$~~37.46~~ *48.53*
425-434	$~~7.18~~ *6.29*	$0.00	$~~7.18~~ *6.29*	$~~30.96~~ *43.19*	$~~38.14~~ *49.48*
435-444	$~~7.35~~ *6.44*	$0.00	$~~7.35~~ *6.44*	$~~31.48~~ *43.98*	$~~38.83~~ *50.42*
445-454	$~~7.52~~ *6.58*	$0.00	$~~7.52~~ *6.58*	$~~32.00~~ *44.78*	$~~39.52~~ *51.36*
455-464	$~~7.68~~ *6.73*	$0.00	$~~7.68~~ *6.73*	$~~32.52~~ *45.58*	$~~40.20~~ *52.31*
465-474	$~~7.85~~ *6.88*	$0.00	$~~7.85~~ *6.88*	$~~33.04~~ *46.38*	$~~40.89~~ *53.26*
475-484	$~~8.02~~ *7.02*	$0.00	$~~8.02~~ *7.02*	$~~33.56~~ *47.18*	$~~41.58~~ *54.20*

(Continued on Sheet No. D-94.30)

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 ~~April 4, 2025~~ *XXXXXX XX, 2026*:

Customer-Owned Equipment

Watts Per Light:	Non-Capacity Energy:	Capacity Energy:	Total Energy:	Delivery:	Monthly Cost Per Light:
15-24	$~~0.33~~ *0.29*	$0.00	$~~0.33~~ *0.29*	$~~6.67~~ *7.47*	$~~7.00~~ *7.76*
25-34	$~~0.49~~ *0.43*	$0.00	$~~0.49~~ *0.43*	$~~7.19~~ *8.26*	$~~7.68~~ *8.69*
35-44	$~~0.66~~ *0.58*	$0.00	$~~0.66~~ *0.58*	$~~7.71~~ *9.06*	$~~8.37~~ *9.64*
45-54	$~~0.83~~ *0.72*	$0.00	$~~0.83~~ *0.72*	$~~8.23~~ *9.86*	$~~9.06~~ *10.58*
55-64	$~~1.00~~ *0.87*	$0.00	$~~1.00~~ *0.87*	$~~8.75~~ *10.66*	$~~9.75~~ *11.53*
65-74	$~~1.16~~ *1.02*	$0.00	$~~1.16~~ *1.02*	$~~9.27~~ *11.46*	$~~10.43~~ *12.48*
75-84	$~~1.33~~ *1.16*	$0.00	$~~1.33~~ *1.16*	$~~9.79~~ *12.25*	$~~11.12~~ *13.41*
85-94	$~~1.50~~ *1.31*	$0.00	$~~1.50~~ *1.31*	$~~10.31~~ *13.05*	$~~11.81~~ *14.36*
95-104	$~~1.66~~ *1.46*	$0.00	$~~1.66~~ *1.46*	$~~10.83~~ *13.85*	$~~12.49~~ *15.31*
105-114	$~~1.83~~ *1.60*	$0.00	$~~1.83~~ *1.60*	$~~11.35~~ *14.65*	$~~13.18~~ *16.25*
115-124	$~~2.00~~ *1.75*	$0.00	$~~2.00~~ *1.75*	$~~11.87~~ *15.45*	$~~13.87~~ *17.20*
125-134	$~~2.17~~ *1.90*	$0.00	$~~2.17~~ *1.90*	$~~12.38~~ *16.24*	$~~14.55~~ *18.14*
135-144	$~~2.33~~ *2.04*	$0.00	$~~2.33~~ *2.04*	$~~12.90~~ *17.04*	$~~15.23~~ *19.08*
145-154	$~~2.50~~ *2.19*	$0.00	$~~2.50~~ *2.19*	$~~13.42~~ *17.84*	$~~15.92~~ *20.03*
155-164	$~~2.67~~ *2.34*	$0.00	$~~2.67~~ *2.34*	$~~13.94~~ *18.64*	$~~16.61~~ *20.98*
165-174	$~~2.83~~ *2.48*	$0.00	$~~2.83~~ *2.48*	$~~14.46~~ *19.44*	$~~17.29~~ *21.92*
175-184	$~~3.00~~ *2.63*	$0.00	$~~3.00~~ *2.63*	$~~14.98~~ *20.23*	$~~17.98~~ *22.86*
185-194	$~~3.17~~ *2.77*	$0.00	$~~3.17~~ *2.77*	$~~15.50~~ *21.03*	$~~18.67~~ *23.80*
195-204	$~~3.34~~ *2.92*	$0.00	$~~3.34~~ *2.92*	$~~16.02~~ *21.83*	$~~19.36~~ *24.75*
205-214	$~~3.50~~ *3.07*	$0.00	$~~3.50~~ *3.07*	$~~16.54~~ *22.63*	$~~20.04~~ *25.70*
215-224	$~~3.67~~ *3.21*	$0.00	$~~3.67~~ *3.21*	$~~17.06~~ *23.43*	$~~20.73~~ *26.64*
225-234	$~~3.84~~ *3.36*	$0.00	$~~3.84~~ *3.36*	$~~17.58~~ *24.22*	$~~21.42~~ *27.58*
235-244	$~~4.01~~ *3.51*	$0.00	$~~4.01~~ *3.51*	$~~18.10~~ *25.02*	$~~22.11~~ *28.53*
245-254	$~~4.17~~ *3.65*	$0.00	$~~4.17~~ *3.65*	$~~18.62~~ *25.82*	$~~22.79~~ *29.47*
255-264	$~~4.34~~ *3.80*	$0.00	$~~4.34~~ *3.80*	$~~19.13~~ *26.62*	$~~23.47~~ *30.42*
265-274	$~~4.51~~ *3.95*	$0.00	$~~4.51~~ *3.95*	$~~19.65~~ *27.42*	$~~24.16~~ *31.37*
275-284	$~~4.67~~ *4.09*	$0.00	$~~4.67~~ *4.09*	$~~20.17~~ *28.22*	$~~24.84~~ *32.31*
285-294	$~~4.84~~ *4.24*	$0.00	$~~4.84~~ *4.24*	$~~20.69~~ *29.01*	$~~25.53~~ *33.25*
295-304	$~~5.01~~ *4.39*	$0.00	$~~5.01~~ *4.39*	$~~21.21~~ *29.81*	$~~26.22~~ *34.20*
305-314	$~~5.18~~ *4.53*	$0.00	$~~5.18~~ *4.53*	$~~21.73~~ *30.61*	$~~26.91~~ *35.14*
315-324	$~~5.34~~ *4.68*	$0.00	$~~5.34~~ *4.68*	$~~22.25~~ *31.41*	$~~27.59~~ *36.09*
325-334	$~~5.51~~ *4.83*	$0.00	$~~5.51~~ *4.83*	$~~22.77~~ *32.21*	$~~28.28~~ *37.04*
335-344	$~~5.68~~ *4.97*	$0.00	$~~5.68~~ *4.97*	$~~23.29~~ *33.00*	$~~28.97~~ *37.97*
345-354	$~~5.84~~ *5.12*	$0.00	$~~5.84~~ *5.12*	$~~23.81~~ *33.80*	$~~29.65~~ *38.92*
355-364	$~~6.01~~ *5.26*	$0.00	$~~6.01~~ *5.26*	$~~24.33~~ *34.60*	$~~30.34~~ *39.86*
365-374	$~~6.18~~ *5.41*	$0.00	$~~6.18~~ *5.41*	$~~24.85~~ *35.40*	$~~31.03~~ *40.81*
375-384	$~~6.35~~ *5.56*	$0.00	$~~6.35~~ *5.56*	$~~25.37~~ *36.20*	$~~31.72~~ *41.76*
385-394	$~~6.51~~ *5.70*	$0.00	$~~6.51~~ *5.70*	$~~25.89~~ *36.99*	$~~32.40~~ *42.69*
395-404	$~~6.68~~ *5.85*	$0.00	$~~6.68~~ *5.85*	$~~26.40~~ *37.79*	$~~33.08~~ *43.64*
405-414	$~~6.85~~ *6.00*	$0.00	$~~6.85~~ *6.00*	$~~26.92~~ *38.59*	$~~33.77~~ *44.59*
415-424	$~~7.02~~ *6.14*	$0.00	$~~7.02~~ *6.14*	$~~27.44~~ *39.39*	$~~34.46~~ *45.53*
425-434	$~~7.18~~ *6.29*	$0.00	$~~7.18~~ *6.29*	$~~27.96~~ *40.19*	$~~35.14~~ *46.48*
435-444	$~~7.35~~ *6.44*	$0.00	$~~7.35~~ *6.44*	$~~28.48~~ *40.98*	$~~35.83~~ *47.42*
445-454	$~~7.52~~ *6.58*	$0.00	$~~7.52~~ *6.58*	$~~29.00~~ *41.78*	$~~36.52~~ *48.36*
455-464	$~~7.68~~ *6.73*	$0.00	$~~7.68~~ *6.73*	$~~29.52~~ *42.58*	$~~37.20~~ *49.31*
465-474	$~~7.85~~ *6.88*	$0.00	$~~7.85~~ *6.88*	$~~30.04~~ *43.38*	$~~37.89~~ *50.26*
475-484	$~~8.02~~ *7.02*	$0.00	$~~8.02~~ *7.02*	$~~30.56~~ *44.18*	$~~38.58~~ *51.20*

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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. D-96.00**

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	
$0.062184	*$0.007201*	*$0.069385*	per kWh for all kWh
~~$0.067926~~	~~$0.003187~~	~~$0.071113~~	

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:	$~~0.028437~~ *0.036673*	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 ~~7.407~~ *6.502*% 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.

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. E-24.00**

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 ~~7.407~~ *6.502*% 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)

M.P.S.C. No. 14 - Electric
Consumers Energy Company **Sheet No. E-26.00**

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%	~~1.004~~ *0.986*%
Customer Voltage Level 2	~~1.328~~ *1.359*%	~~2.296~~ *2.247*%
Customer Voltage Level 3	~~3.300~~ *3.268*%	~~7.407~~ *6.502*%

(Continued on Sheet No. E-27.00)

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual and Projected Information Technology Operations O&M Expense

For the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 20, 2027

($000)

Case No.: U-21870
Exhibit No.: A-17 (SHB-1)
Page: 1 of 2
Witness: SHBaker
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical		**Projected**		
Line No.	**Description**	**12 Mos Ended 12/31/2024**	**12 Mos Ending 12/31/2025**	**12 Mos Ending 12/31/2026**	**4 Mos Ending 4/30/2027**	**12 Mos Ending 4/30/2027**
1	**Information Technology**	**42,127**	**47,095**	**54,964**	**18,654**	**55,297**
	Labor	9,279	10,788	10,793	3,596	10,792
	Material	1,297	1,945	1,946	648	1,946
	Contractor	7,317	8,584	8,588	2,862	8,587
	Contracts	22,273	24,397	32,254	11,087	32,590
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	1,960	1,382	1,382	461	1,382
2	**Security**	**9,277**	**11,365**	**11,362**	**3,787**	**11,362**
	Labor	3,841	4,629	4,628	1,543	4,628
	Material	19	-	-	-	-
	Contractor	1,360	1,958	1,957	652	1,957
	Contracts	3,278	4,454	4,453	1,484	4,453
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	778	323	323	108	323
3	**Total IT Operations O&M Expense**	**51,403**	**58,460**	**66,327**	**22,441**	**66,659**
	Labor	13,120	15,417	15,422	5,139	15,420
	Material	1,316	1,945	1,946	648	1,946
	Contractor	8,677	10,542	10,546	3,514	10,545
	Contracts	25,551	28,851	36,707	12,571	37,042
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	2,738	1,705	1,706	568	1,705

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of IT Operations O&M Expenses Projected Using Merit and Inflation
For the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
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Date: June 2025

Line No.	Description	2024 Actual	Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 12 Mos Ending Dec 31, 2026	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	Merit & Inflation 4 Mos Ending Apr 30, 2027	Other Adjustments	Projected O&M 12 Mos Ending Apr 30, 2027
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Information Technology**	**42,127**	**9,279**	**195**	**9,474**	**227**	**9,701**	**78**	**12,670**	**55,297**
	Labor	9,279	9,279	195	9,474	227	9,701	78	1,013	10,792
	Material	1,297		0		0		0	648	1,946
	Contractor	7,317		0		0		0	1,270	8,587
	Contracts	22,273		0		0		0	10,316	32,590
	Non-Labor Overheads	0		0		0		0	0	0
	Non-Labor Other	1,960		0		0		0	-578	1,382
2	**Security**	**9,277**	**3,841**	**81**	**3,922**	**94**	**4,016**	**32**	**1,878**	**11,362**
	Labor	3,841	3,841	81	3,922	94	4,016	32	580	4,628
	Material	19		0		0		0	-19	0
	Contractor	1,360		0		0		0	597	1,957
	Contracts	3,278		0		0		0	1,175	4,453
	Non-Labor Overheads	0		0		0		0	0	0
	Non-Labor Other	778		0		0		0	-455	323
3	**Total IT Operations O&M Expenses**	**$ 51,403**	**$ 13,120**	**$ 276**	**$ 13,396**	**$ 322**	**$ 13,718**	**$ 110**	**$ 14,548**	**$ 66,659**
	Labor	13,120	13,120	276	13,396	322	13,718	110	1,593	15,420
	Material	1,316	0	0	0	0	0	0	630	1,946
	Contractor	8,677	0	0	0	0	0	0	1,868	10,545
	Contracts	25,551	0	0	0	0	0	0	11,491	37,042
	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
	Non-Labor Other	2,738	0	0	0	0	0	0	-1,033	1,705

Notes

	12-Mo Ending 2025	12-Mo Ending 2026	4-Mo Ending 2027
Annual inflation rates per Company witness Daly	2.1%	2.4%	2.4%
Number of months in the period	12	12	4
Pro-rated inflation rate	2.1%	2.4%	0.8%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Historical 13 Month Average of IT Cloud Computing Prepaid Balance
For the years 2023 - 13 months balance ending December 31, 2024
Electric Allocation

Case No.: U-21870
Exhibit No.: A-18 (SHB-2)
Page: 1 of 2
Witness: SHBaker
Date: June 2025

Line No.	(a) Description	(b) Bal. Ended 12/31/2023	(c) Bal. Ended 1/31/2024	(d) Bal. Ended 2/29/2024	(e) Bal. Ended 3/31/2024	(f) Bal. Ended 4/30/2024	(g) Bal. Ended 5/31/2024	(h) Bal. Ended 6/30/2024	(i) Bal. Ended 7/31/2024	(j) Bal. Ended 8/31/2024	(k) Bal. Ended 9/30/2024	(l) Bal. Ended 10/31/2024	(m) Bal. Ended 11/30/2024	(n) Bal. Ended 12/31/2024	(o) 13 mos. Average
1	**IT Cloud Computing Prepaid**	$ (3,946,814)	$ (9,504,689)	$ (8,809,041)	$ (9,431,270)	$ (9,188,763)	$ (8,496,262)	$ (7,503,585)	$ (6,525,295)	$ (5,831,386)	$ (5,439,741)	$ (4,434,805)	$ (3,468,222)	$ (3,126,233)	**$ (6,592,777)**
2	**Total**	**$ (3,946,814)**	**$ (9,504,689)**	**$ (8,809,041)**	**$ (9,431,270)**	**$ (9,188,763)**	**$ (8,496,262)**	**$ (7,503,585)**	**$ (6,525,295)**	**$ (5,831,386)**	**$ (5,439,741)**	**$ (4,434,805)**	**$ (3,468,222)**	**$ (3,126,233)**	**$ (6,592,777)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected 13 Month Average of IT Cloud Computing Prepaid Balance
For the years 2026 - 13 months balance ending April 30, 2027
Electric Allocation

Case No.: U-21870
Exhibit No.: A-18 (SHB-2)
Page: 2 of 2
Witness: SHBaker
Date: June 2025

Line No.	(a) Description	(b) Bal. Ending 4/30/2026	(c) Bal. Ending 5/31/2026	(d) Bal. Ending 6/30/2026	(e) Bal. Ending 7/31/2026	(f) Bal. Ending 8/31/2026	(g) Bal. Ending 9/30/2026	(h) Bal. Ending 10/31/2026	(i) Bal. Ending 11/30/2026	(j) Bal. Ending 12/31/2026	(k) Bal. Ending 1/31/2027	(l) Bal. Ending 2/28/2027	(m) Bal. Ending 3/31/2027	(n) Bal. Ending 4/30/2027	(o) 13 mos. Average
1	**IT Cloud Computing Prepaid**	$ 9,031,737	$ 8,668,059	$ 8,250,979	$ 7,618,539	$ 7,149,336	$ 6,493,824	$ 5,314,858	$ 4,155,623	$ 3,016,547	$ 10,160,223	$ 9,158,201	$ 8,007,526	$ 9,626,293	**$ 7,434,750**
2	**Total**	**$ 9,031,737**	**$ 8,668,059**	**$ 8,250,979**	**$ 7,618,539**	**$ 7,149,336**	**$ 6,493,824**	**$ 5,314,858**	**$ 4,155,623**	**$ 3,016,547**	**$ 10,160,223**	**$ 9,158,201**	**$ 8,007,526**	**$ 9,626,293**	**$ 7,434,750**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Information Technology Investments O&M Expense
For the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-19 (SHB-3)
Page: 1 of 2
Witness: SHBaker
Date: June 2025

Line No.	(a) Description	(b) Historical 12 Mos Ended 12/31/2024	(c) 12 Mos Ending 12/31/2025	(d) Projected 12 Mos Ending 12/31/2026	(e) 4 Mos Ending 4/30/2027	(f) 12 Mos Ending 4/30/2027
	Investments Planning					
1	**Information Technology**	**1,048**	**686**	**686**	**229**	**686**
	Labor	467	686	686	229	686
	Software	-	-	-	-	-
	Material	-	-	-	-	-
	Contractor	581	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	(0)	-	-	-	-
2	**Security**	**13**	**8**	**8**	**3**	**8**
	Labor	12	8	8	3	8
	Software	-	-	-	-	-
	Material	-	-	-	-	-
	Contractor	0	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	-	-	-	-	-
	Investments					
3	**Information Technology**	**6,787**	**11,692**	**23,862**	**8,195**	**24,103**
	Labor	1,660	6,138	7,142	2,220	6,981
	Software	362	307	5,254	2,302	5,805
	Material	194	629	2,608	782	2,520
	Contractor	4,833	3,299	6,962	2,294	6,935
	Non-Labor Overheads	-	997	668	195	640
	Non-Labor Other	(262)	322	1,229	403	1,222
4	**Security**	**689**	**787**	**1,613**	**430**	**1,505**
	Labor	288	457	1,034	321	1,010
	Software	97	131	309	15	221
	Material	161	14	22	8	23
	Contractor	144	56	69	16	63
	Non-Labor Overheads	-	67	147	62	160
	Non-Labor Other	(0)	62	31	7	27
5	**Total Investments O&M Expense**	**8,536**	**13,174**	**26,169**	**8,857**	**26,303**
	Labor	2,427	7,290	8,870	2,772	8,686
	Software	459	439	5,563	2,317	6,026
	Material	355	643	2,630	790	2,544
	Contractor	5,558	3,355	7,031	2,310	6,998
	Non-Labor Overheads	-	1,064	815	256	800
	Non-Labor Other	(262)	384	1,260	410	1,250

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Investments O&M Expenses Projected Using Merit and Inflation
For the Years 2024, 2025, 2026, and Test Year 12 Months Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-19 (SHB-3)
Page: 2 of 2
Witness: SHBaker
Date: June 2025

Line No.	Description	(a)	(b) 2024 Actual	(c) Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2024	(d) Merit & Inflation 12 Mos Ending Dec 31, 2025	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(f) Merit & Inflation 12 Mos Ending Dec 31, 2026	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	(h) Merit & Inflation 4 Mos Ending Apr 30, 2027	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Apr 30, 2027
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
	Investments Planning										
1	**Information Technology**		**1,048**	**0**	**0**	**0**	**0**	**0**	**0**	**-362**	**686**
	Labor		467		0		0		0	219	686
	Software		0		0		0		0	0	0
	Material		0		0		0		0	0	0
	Contractor		581		0		0		0	-581	0
	Non-Labor Overheads		0		0		0		0	0	0
	Non-Labor Other		0		0		0		0	0	0
2	**Security**		**13**	**0**	**0**	**0**	**0**	**0**	**0**	**-4**	**8**
	Labor		12		0		0		0	-4	8
	Software				0		0		0	0	0
	Material		0		0		0		0	0	0
	Contractor		0		0		0		0	0	0
	Non-Labor Overheads		0		0		0		0	0	0
	Non-Labor Other		0		0		0		0	0	0
	Investments										
3	**Information Technology**		**6,787**	**0**	**0**	**0**	**0**	**0**	**0**	**17,317**	**24,103**
	Labor		1,660		0		0		0	5,321	6,981
	Software		362		0		0		0	5,443	5,805
	Material		194		0		0		0	2,326	2,520
	Contractor		4,833		0		0		0	2,102	6,935
	Non-Labor Overheads		0		0		0		0	640	640
	Non-Labor Other		-262		0		0		0	1,484	1,222
4	**Security**		**689**	**0**	**0**	**0**	**0**	**0**	**0**	**816**	**1,505**
	Labor		288		0		0		0	722	1,010
	Software		97		0		0		0	124	221
	Material		161		0		0		0	-137	23
	Contractor		144		0		0		0	-81	63
	Non-Labor Overheads		0		0		0		0	160	160
	Non-Labor Other		0		0		0		0	27	27
5	**Total Investments O&M Expense**		**$ 8,536**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 17,766**	**$ 26,303**
	Labor		2,427	0	0	0	0	0	0	6,259	8,686
	Software		459	0	0	0	0	0	0	5,567	6,026
	Material		355	0	0	0	0	0	0	2,189	2,544
	Contractor		5,558	0	0	0	0	0	0	1,440	6,998
	Non-Labor Overheads		0	0	0	0	0	0	0	800	800
	Non-Labor Other		-262	0	0	0	0	0	0	1,512	1,250

Notes

	12-Mo Ending 2025	12-Mo Ending 2026	4-Mo Ending 2027
Annual inflation rates per Company witness Daly	2.1%	2.4%	2.4%
Number of months in the period	12	12	4
Pro-rated inflation rate	2.1%	2.4%	0.8%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No.: A-20 (SHB-5)
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Witness: SHBaker
Date: June 2025

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 2024, 2025, 2026, and 2027
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
1	2024	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, (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 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.	2024-01-01	2024-12-31	-	-	399,627		-	-	-	-	-	-	-	-	251,768	-	-	-	57,513	194,252	-	-
2	2024	Asset Accounting Upgrade	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 2022, 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. The current monthly allocation process has limited visibility to Company financial performance, and the upgrade provides functionality that allows more frequent allocation processes. Additionally, implementing the vendor's regulatory module eliminates the time-consuming and labor-intensive process of manual data extracts for regulatory analysis used for Cost of Service modeling. 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) eliminating the labor intensive and time-consuming process of pulling data for regulatory analysis used for Cost of Service; (3) automating manual tasks; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) upgrading the vendor software from the current version to the newer version; (2) implementing new functionality that includes features for the regulatory Cost of Service analysis, additional reporting, job scheduling, and centralized error processing; and (3) populating the data lake with data from the asset accounting system for improved reporting. Alternatives considered include: (1) Upgrade to the newest, cloud version of PowerPlan. 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. (2) Evaluate 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 likely be more complex, cost more, and may not provide all the required features. (3) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements.	2021-09-27	2022-11-11	(0.99)	4,630,550	247,824		-	-	-	-	-	-	-	9,327	-	-	-	9,327	-	-
3	2024	Product Family Enhancements-Corporate-Capital	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. 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.	2024-01-01	2024-12-31	(1.00)	1,256,844	132,658		875,392	254,362	1,622	164,144	401,685	-	53,579	83,575	47,124	-	6,660	29,791	-	-
4	2024	Product Family Enhancements-Corporate-O&M	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 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.	2024-01-01	2024-12-31	(1.00)	-	403,718		-	-	-	-	-	-	-	254,343	-	98	62,975	191,271	-	-
5	2024	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. 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.	2023-02-27	2025-12-20	(1.00)	832,903	479,821		36,434	-	-	1,888	34,202	-	344	113,574	-	-	2,719	110,855	-	-
6	**SUBTOTAL**	**2024 Corporate**										**911,825**	**254,362**	**1,622**	**166,032**	**435,887**	**-**	**53,923**	**712,583**	**47,124**	**98**	**129,867**	**535,496**	**-**	**-**

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
7	2024	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, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the 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.	2024-01-01	2024-12-31	-	-	63,362		-	-	-	-	-	-	-	39,918	-	-	4,675	35,243	-	-
8	2024	Bill Redesign	Software(Intangible)	Customer	Prior period adjustment.							(6,137)	-	-	(4,939)	-	-	(1,199)	-	-	-	-	-	-	-
9	2024	Click to Chat	Software(Intangible)	Customer	Prior period adjustment.							6,789	178,821	-	380	(176,592)	-	4,180	225	-	-	12	213	-	-
10	2024	Energy Assistance Enhancements and Maintenance Annual Updates	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 (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.	2024-01-01	2024-12-31	-	-	344,400		-	-	-	-	-	-	-	216,972	-	-	120,866	96,106	-	-
11	2024	Enhancements - Customer Experience and Operations- Cap	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 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. 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.	2024-01-01	2024-12-31	(1.00)	563,792	41,582		392,681	-	-	148,845	198,745	-	45,091	26,197	-	-	7,719	18,478	-	-
12	2024	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 CE&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 technology 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.	2024-01-01	2024-12-31	(1.00)	-	144,202		-	-	-	-	-	-	-	90,847	-	-	34,090	56,758	-	-
13	2024	Genesys Cloud Migration	Software(Intangible)	Customer	The project will migrate the Company 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 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 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 Companys 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.	2024-07-02	2025-06-30	(0.80)	-	231,867		-	-	-	-	-	-	-	94,772	-	-	692	94,079	-	-
14	2024	Product Family Enhancements-Customer-Capital	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 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.	2024-01-01	2024-12-31	(1.00)	1,573,482	861,943		1,095,930	-	-	220,273	805,249	-	70,408	543,024	-	-	57,918	485,106	-	-
15	2024	Product Family Enhancements-Customer-O&M	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 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.	2024-01-01	2024-12-31	(1.00)	-	81,100		-	-	-	-	-	-	-	51,093	-	-	7,429	43,664	-	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
16	2024	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.	2024-01-01	2024-12-31	-	-	268,569		-	-	-	-	-	-	-	169,198	-	-	8,861	160,338	-	-
17	2024	SiteCore Upgrade	Software(Intangible)	Customer	Prior period adjustment.							-	-	-	-	-	-	-	12	-	-	12	-	-	-
18	**SUBTOTAL**	**2024 Customer**										**1,489,263**	**178,821**	**-**	**364,560**	**827,402**	**-**	**118,480**	**1,232,258**	**-**	**-**	**242,273**	**989,985**	**-**	**-**
19	2024	Electric Operations Field Devices for Journey Workers and Apprentices	New Computers / Hardw	Electric	Prior period adjustment.							620	-	-	-	620	-	-	-	-	-	-	-	-	-
20	2024	Ransomware Recovery-OT-Electric & Generation	New Computers / Hardw	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 (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 r the regulatory ramifications such action would result in.(2) Restoring from tape is a possibility but significantly increases OT estoration 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.	2025-02-10	2025-12-31	(1.00)	5,515,728	142,629		4,722,760	3,124,751	1,183,085	232,136	114,571	-	68,217	33,717	33,819	17,936	7,854	(25,892)	-	-
21	2024	Cascade Modernization and Prioritization	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.	2024-10-17	2025-10-10	(1.00)	373,801	51,473		287,306	-	-	16,819	262,688	-	7,798	6,028	-	-	4,262	1,766	-	-
22	2024	Catastrophic Crewing (CatCrew) Version 2.0	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.	2024-10-21	2025-11-14	5.02	2,421,749	310,938		695,169	-	-	177,863	463,556	-	53,750	30,598	-	-	8,499	22,099	-	-
23	2024	Electric Geographic Information System (GIS) Platform Upgrade	Software(Intangible)	Electric	This project will upgrade the GIS platform applications, servers, application hosting servers, and databases to the next major versions to remediate the outdated platform technology. The project adds value by: (1) remediating GIS, Windows, and Citrix technology obsolescence, creating a stable and sustainable foundational platform for critical business functions; (2) improving platform resilience by remediating current single-point-of-failure areas; (3) sharing technology resources (servers, databases, etc.) across gas and electric platforms to optimize them, yet still ensuring the ability to meet diverse business area functional needs; and (4) adding new capabilities for spatial analytics, real-time visualization of data, and three-dimensional infrastructure network traceability. In addition, the GIS platform remediation work establishes the foundation necessary for the full implementation of the Electric Distribution Asset Management Program. Project scope includes: (1) building GIS platform servers, software, and data; (2) expanding GIS platform capabilities; (3) re-architecting current single-point-of-failure areas; (4) designing and developing new architecture; (5) upgrading database technology; (6) re-platforming the application hosting platform (Citrix); and (7) upgrading and reconfiguring applications that utilize the GIS platform. The alternatives considered for the project were to: (1) delay implementation, pay a premium for extended Windows support, and incur cyber security and business continuity risk for the application hosting platform and the GIS platform; (2) upgrade the platform to the Utility Network as a big bang approach without the incremental GIS version upgrade; and (3) perform an iterative platform upgrade to the next GIS version with application platform hosting upgrade, server replacements, and database upgrade, and shift the Utility Network upgrade to a future year. Option 1 was not selected since further project delays will prolong the security and business continuity risk, as well as increase the probability of risk impact due to the level of effort required to complete the project. Option 2 was not selected because the Utility Network upgrade effort is a transformational technology project, requiring extensive data migration in addition to the scope outlined in this project. Furthermore, this alternative will also incur security and business continuity risk given the complexity of a prolonged planning and design effort. Option 3 was selected to implement an iterative upgrade approach as it decreases the overall project complexity while mitigating aging technology platforms. This will enable the future upgrade to the Utility Network in addition to addressing overall platform stability and sustainability in a timelier manner.	2019-12-30	2024-05-20	(1.00)	2,632,499	251,575		295,844	-	-	134,455	88,667	-	72,722	104,642	-	-	83,055	21,587	-	-
24	2024	Electric Infrastructure Attachments	Software(Intangible)	Electric	The Company currently collects $5.6M per year as revenue in rent from over 400 third party entities that have attached equipment to Company infrastructure, primarily on distribution poles. There has been exponential growth in attachment requests as Internet providers continue to build out their broadband cable networks. The Electric Infrastructure Attachments (IA) project will implement a technology solution that automates manual processes and supports current and future information storage, processing and reporting needs. The Infrastructure Attachments department currently uses a Microsoft Access database, developed in the early 2000's to support the processes that generate $5.6M in revenue in the form of 3rd party rental of distribution pole space. This obsolete database is used to store an exponentially increasing volume of critical pole attachment information that includes; client usage, contact information and other billing information; active and completed permit application data; and other information necessary to meet external reporting requirements. Due to the limited functionality in the current database, significant manual effort is required for records research, negatively impacting the ability of the Infrastructure Attachments team to support information requests from clients, external entities and departments across the Company. Additionally, benchmarking with other utilities and examination of best practices, indicates that the current solution has significant gaps in capabilities that are standard with newer technologies such as searchable geographically referenced records. The benefits of implementing a Commercial Off The Shelf (COTS) pole attachment technology solution include providing the current functionality in a supportable solution as well as; (1) providing new capabilities to further automate manual processes, (2) reducing manual effort through integration with SAP, GIS, the National Joint Utility Notification System (NJUNS), (3) providing a more efficient approach to fulfill information requests; (4) affording a history of pole attachments at a specific location; and (5) reducing waste through improved processes. The scope of this project includes; (1) evaluate, select and purchase a COTS Infrastructure Attachments solution, (2) design, develop and implement required integrations and, (3) configure, test and implement the end to end solution. Alternatives considered include; (1) Select and implement a fully integrated COTS solution to replace the existing functionality of the Access database, (2) develop an in-house replacement for the Access database and (3) continue to use the current Access database. Alternative two was not chosen because this option would not integrate with Corporate systems, exasperating ongoing issues with data discrepancies and client dissatisfaction making it an inferior solution. Alternative three is unacceptable due to the stated business risks. The first alternative was selected because it will provide for an integrated and supported solution.	2021-04-26	2024-12-31	-	1,327,468	163,652		273,395	344,500	-	28,581	(153,578)	-	53,892	43,210	-	-	3,534	39,677	-	-

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 2024, 2025, 2026, and 2027
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
25	2024	Electric ProjectWise	Software(Intangible)	Electric	ProjectWise is a suite of project collaboration software for engineering projects currently in use at the Company by Transmission Pipeline, Storage, System Integrity, Compression, Metering & Regulation, Distributed Energy Resources, and Generation Engineering teams. It is capable of bundling, managing, and handling the versions of records and documents related to designs, proposals, contract resources, and record-keeping. The Electric ProjectWise project will expand the implementation of the software to Electric High Voltage Distribution Planning and Design, Low Voltage Distribution Planning and Design, and Sub Metro Engineering. The software can also be used to facilitate the management of change process across the Electric Grid Integration. Need approval for all work items to complete project: Work ID 8857/10681 Projectwise; 12097/12094 Fund PW Change Champion; 12092/12093 Fund additional PW License Costs (2022 only) As part of the Company's shift towards renewable assets along with modernizing the grid, the Company is deploying renewable assets that tie into both LVD & HVD distribution systems along with grid modernization devices across the distribution system. There are many process and technology inter-dependencies related to managing our engineering records within Electric Grid Integration (EGI). Across EGI there are several processes and systems utilized to manage the records related to our assets. Some of the processes are not documented or the documentation is not up to date. This creates limited standardization related to what records are kept for each asset type, and what documentation is turned over to Operations as part of the closeout process. Long term this impacts the operability of these assets and limits how well the Company can maintain these assets without complete engineering records. Key problems manifesting as a result include no single source of truth for our engineering records for assets that blur the lines of HVD/LVD/Generation, lack of standardized process for records management, limited integration with EPM's Project Management Information System, and impacts Customer Energy Management (CEM) who will utilize ProjectWise for Gas Assets in the near future with integration with SAP. Several key problem themes have been identified by internal stakeholders around the current state of EGI's engineering records management at the Company including: (1) limited agility/flexibility of the team as each asset type has its own processes and tools; (2) no uniform document repository to manage records for the complete lifecycle for Electric Grid Integration (3) lack of adherence or no standardized processes; and (4) limited ability to integrate with internal and external stakeholders (Enterprise Project Management, Electric Operations, CEM, A/E firms, and International Transmission Company (ITC) are examples). Completion of this project will provide value to the Company by: (1) providing a centralized repository for document retention, archival and version tracking, resulting in records that are traceable and retrievable; (2) improving comprehensive documentation to be inclusive of all design review changes from key technical Subject Matter Expert (SME) groups; (3) enabling end to end workflow tracking and approval sign-off from initial design and engineering through final sign-off; (4) improving consistency with technical records across project and asset lifecycles; (5) decreasing risk of not having complete and accurate records that are readily accessible and easily searchable; (6) enabling tracking of temporary and permanent electric distribution system configuration changes in a centralized repository; (7) enhancing spatial relationships within drawings and documents such that all documents pertinent to a geographic location can be quickly accessed and maintained; (8) creating a universal system of record for all native construction prints; (9) enabling tracking of project as-built and final project record completion. The project provides additional value by implementing management of change tool with capabilities that can be leveraged by other departments throughout the Company. The scope of this project encompasses the implementing ProjectWise software modules for use by Customer Energy Management (CEM), LVD Planning and Design, Underground Metro Planning and Design, HVD Planning and Design, and Electric Operations Departments. The project will: (1) configure the software modules within the application, and (2) design and develop integrations with other Company systems. Prior to the project start, the team will work collaboratively with the Electric Grid Integration organization to develop an engineering records management rollout plan that is aligned with business processes. Alternatives considered include: (1) Continue current engineering records processes. This alternative was not selected because it significantly increases the cost and effort over time, resulting in waste for Engineering and Operations as the Company deploys its long-term capital investments into grid modernization along with a shift from fossil generation plants towards distributed energy resources. This alternative also limits the integration with the planned upgrade of the Geographic Information System (GIS) along with the planned rollout of the Distribution Asset Management processes and program. (2) Develop an engineering records management tool and processes for LVD only to support the rollout of ProjectWise to CEM. This alternative was not selected because it limits change to just LVD and does not support integration with Distributed Energy Resources assets across LVD & HVD. (3) Develop an engineering records management rollout plan and supporting business case that aligns processes and tools initiatives into one program, taking a phased approach to develop and implement the strategy. This alternative was selected because it starts by identifying and addressing key gaps that have been identified, which includes closing the gap of the lack of a standardized process for engineers and designers to create and managed engineering records. Furthermore, this alternative will provide a uniform process and platform for both Engineering and Operations to gain access to our records, and additionally addresses the technology and process inter-dependency gaps that are presently planned in silos with design tools, GIS, and Asset Management. Finally, this alternative optimizes engineering records management across both generation and Electric Distribution and mirror planned work in the gas business units.	2022-02-10	2024-05-31	(1.00)	44,412	198,314		8,770	-	-	7,119	76	-	1,575	7,215	-	-	7,163	51	-	-
26	2024	Generation Operations Digital Work Management	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. 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.	2023-10-30	2025-12-30	(1.00)	1,224,960	69,756		73,481	-	-	36,192	28,108	-	9,180	4,496	-	-	3,290	1,047	-	159
27	2024	GM-GIS Connectivity Model Integration	Software(Intangible)	Electric	The Grid Modernization (GM) Geographic Information System (GIS) Connectivity Model Integration project will design, develop, and implement a GIS extract using an industry standard to publish electric GIS data to the network, where it can be consumed by multiple applications. The extract will make the data available to the electric metering historian as well as other applications in the future. Interfaces between systems are currently designed, developed and implemented based on requirements that are specific to a particular project or system, while using an application to application (point to point) communications architecture. Maintaining these custom developed integrations is costly and complex. The project provides value to the Company by: (1) leveraging the International Electrotechnical Commission (IEC) Common Information Model (CIM), which provides a basic ontology for data and data relationships and a standard repeatable approach that can be leveraged for sharing data about the electrical network across technical systems; (2) supporting an enterprise application integration framework, which keeps business process as simple as possible; (3) providing the ability to detect the physical location of metered assets, including circuit, substations and transformers; and (4) reducing the costs and time required to develop integrations in the future resulting from streamlined approaches and processes. Deliverables within the project scope include: (1) develop and implement the GIS extract, leveraging IEC CIM for data sharing; (2) leverage the enterprise service bus (ESB) as the high level communications protocol for sharing CIM data across the enterprise; (3) build the integration to the electric metering historian; and (4) develop a data and integration framework that can be leveraged for future projects. The alternative considered was to continue to implement point-to-point application-specific integrations to meet the requirements specific to a single project. This alternative was not chosen because it continues to increase the technical debt associated with the maintenance of non-standard interfaces. The preferred approach as outlined in this business case will result in: (1) standard, repeatable approaches for future integrations, (2) lower ongoing maintenance costs and, (3) less complexity.	2021-04-13	2024-06-24	(1.00)	1,155,108	180,106		-	-	-	-	-	-	-	25,518	-	-	-	25,518	-	-
28	2024	Live Wiredown Detection and ADMS Upgrade	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 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. 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.	2021-03-22	2025-05-16	(1.00)	1,562,899	46,423		1,275,271	-	-	741,592	307,255	-	226,424	22,374	2	-	21,222	1,150	-	-
29	2024	Product Family Enhancements-Electric-Capital	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 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.	2024-01-01	2024-12-31	(1.00)	563,082	217,469		563,082	-	-	147,552	343,624	-	71,905	217,469	-	-	62,337	435,131	-	(280,000)

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
30	2024	Product Family Enhancements-Electric-O&M	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 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.	2024-01-01	2024-12-31	(1.00)	-	144,083		-	-	-	-	-	-	-	144,083	-	1,558	63,937	78,587	-	-
31	**SUBTOTAL**	**2024 Electric**										**8,195,698**	**3,469,251**	**1,183,085**	**1,522,310**	**1,455,588**	**-**	**565,464**	**639,350**	**33,822**	**19,494**	**265,153**	**600,721**	**-**	**(279,841)**
32	2024	Application Currency-Electric & Gas Shared-Capital	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, (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 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.	2024-01-01	2024-12-31	(1.00)	739,892	137,627		515,335	367,679	-	66,751	40,495	-	40,409	86,705	69,025	-	13,459	4,222	-	-
33	2024	Application Currency-Electric & Gas Shared-O&M	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 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.	2024-01-01	2024-12-31	(1.00)	-	63,329		-	-	-	-	-	-	-	39,898	-	-	9,734	30,164	-	-
34	2024	Application Currency-Operational Technology-Capital	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	2024-01-01	2024-12-31	(1.00)	71,559	3,905		49,841	-	35,885	10,451	476	-	3,028	2,460	-	-	2,423	37	-	-
35	2024	Application Currency-Operational Technology-O&M	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.	2024-01-01	2024-12-31	(1.00)	-	96,068		-	-	-	-	-	-	-	60,523	-	99	45,737	13,484	-	1,203
36	2024	Application Currency-TEOS-O&M	Software(Intangible)	Electric & Gas Shared	The TEOS 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 TEOS 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 TEOS 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.	2024-01-01	2024-12-31	(1.00)	-	234,753		-	-	-	-	-	-	-	147,894	-	-	63,447	84,409	-	38

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 2024, 2025, 2026, and 2027
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
37	2024	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.	2024-01-01	2024-12-31	(1.00)	343	3,168		239	-	-	-	-	-	239	2,008	-	-	-	2,008	-	-
38	2024	Enhancements-TEOS-Capital	Software(Intangible)	Electric & Gas Shared	The TEOS 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 TEOS 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 TEOS. 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 Gas Engineering, Customer Energy Management, Electric Grid Integration, and Fleet. 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.	2024-01-01	2024-12-31	(1.00)	17,468	1,576		12,166	-	-	5,545	55	-	6,566	993	-	-	819	174	-	-
39	2024	Field Contractor Work Management Technology Enablement	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/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. 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 ServiceBanch. 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	2025-02-24	(0.85)	1,684,862	740,394		915,148	-	176,116	228,225	424,138	-	86,669	221,463	10,758	1,832	100,180	107,867	-	826
40	2024	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.	2020-11-30	2025-04-30	(0.72)	3,843,392	77,336		520,449	-	-	159,265	305,609	-	55,575	9,885	-	-	-	9,885	-	-
41	2024	Field Network Director	Software(Intangible)	Electric & Gas Shared	Prior period adjustment.							18,795	-	(62,021)	-	62,021	-	18,795	-	-	-	-	-	-	-
42	2024	OSIsoft PI Historian Upgrade 2020	Software(Intangible)	Electric & Gas Shared	Prior period adjustment.							901	901	-	-	-	-	-	-	-	-	-	-	-	-
43	2024	Product Family Enhancements-Electric & Gas Shared-Capital	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 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.	2024-01-01	2024-12-31	(1.00)	1,538,445	394,820		1,071,527	-	1,839	162,777	857,303	-	49,608	248,736	-	-	18,681	230,056	-	-
44	2024	Product Family Enhancements-Electric & Gas Shared-O&M	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. 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 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.	2024-01-01	2024-12-31	(1.00)	-	78,377		-	-	-	-	-	-	-	49,377	-	-	6,611	42,766	-	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
45	2024	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-end 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.	2023-12-04	2025-11-01	(1.00)	2,888,762	125,527		514,706	162,334	-	31,995	236,253	-	84,125	11,672	-	-	4,100	7,571	-	-
46	2024	Work Management Scheduling Analytics and Reporting	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. TheÂ Distribution Planning, Scheduling and Administrative Support & Financial Services (Work Plan Strategy) teams are utilizing manually intensive work methods,Â systems and forecasting models. These inefficiencies impact the creation ofÂ work plans, lack predictive capacity planning, and reduce productivity ofÂ operational partners. The project will add value by providing: (1) streamlinedÂ processes tied to workload review and preparatoryÂ analysis,Â leading to increased focus on workload priority, execution of workÂ and a reduction of human struggle;Â (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 manualÂ scheduling steps, reporting and analysis of data associated with work management processes andÂ systems; therebyÂ minimizing the risk of human error hours spentÂ developing and updating crewÂ route sheets;Â and (4) improved forecasting accuracy,Â that results in greater transparency into the weekly schedule and associatedÂ workÂ plan. The project scope includes:Â (1) implement a solution to facilitate the review of work ordersÂ from various engineering organizations, allowing for streamlined check-in of work orders; (2) implement aÂ scheduling tool that utilizes predictive modelling and advanced analytics and streamlines daily schedule modifications;Â (3) enhanceÂ integration with the Arcos application to bring in employee capacity and availability information;Â (4)Â integrate with SAP to retrieve work order data and manage record keeping requirements;Â (5) enhanceÂ integration with Field Service Suite (FSS) for quicker access to MISS DIG information and work orderÂ assignments;Â 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	2025-06-13	-	1,880,176	163,956		71,991	-	-	26,282	36,474	-	9,235	29,461	17,309	12,152	-	-	-	-
47	**SUBTOTAL**	**2024 Electric & Gas Shared**										**3,691,098**	**530,914**	**151,819**	**691,292**	**1,962,824**	**-**	**354,248**	**911,076**	**97,092**	**14,084**	**265,190**	**532,644**	**-**	**2,066**
48	2024	800 MHZ Modernization	Network	IT/Digital Foundation	Prior period adjustment.							(117,394)	-	-	-	(117,394)	-	-	319	-	-	319	-	-	-
49	2024	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.Â 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.Â In addition, aging equipment cannot accommodate the increasing demand for wireless devices necessary to perform day-to-day operations thatÂ rely on wireless-enabled devices, such as rugged field devices, cell phones, barcode scanners, tablets, and other mobile devices.Â As equipment ages, it is at risk of higher failure rates, which increases the risk of unplanned outages.Â 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 employeesÂ 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.	2024-01-01	2024-12-31	(1.00)	3,046,329	58,589		1,633,137	246,792	930,223	246,869	142,684	-	66,569	36,911	-	21,759	9,083	6,069	-	-
50	2024	ARP-Radio	Network	IT/Digital Foundation	This project will refresh hardware to include; 800Mhz Radios, 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 and 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 best-in-class 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. 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 1 was not selected because it requires replacement of existing management systems which are vendor specific and would need to also be replaced if the Company were to move to different equipment. This would result in a significantly higher investment. Option 2 was selected as this has the least disruption to radio and mobile data system users and deliver the highest value and lowest cost solution to meet the objectives of this Business Case.	2024-01-01	2024-12-31	(1.00)	1,164,618	94,010		624,352	-	541,818	(113,569)	186,618	-	9,485	59,227	-	34,782	3,852	20,577	-	15
51	2024	ARP-Collaboration	New Computers / Hardw	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 ssets 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.	2024-01-01	2024-12-31	(1.00)	1,115,559	127,002		776,987	34,775	486,292	17,724	231,177	-	7,019	80,011	-	13,640	421	65,951	-	-
52	2024	ARP-Field Device Asset Management (FDAM)	New Computers / Hardw	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 can be very difficult to 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 workstations 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. 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.	2024-01-01	2024-12-31	(1.00)	3,952,991	2,752		2,753,258	-	2,675,939	30,906	38,134	-	8,280	1,734	-	1,734	-	-	-	-
53	2024	ARP-Operational Technology Support Electric	New Computers / Hardw	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 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. 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 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.	2024-01-01	2024-12-31	-	2,244,726	22,071		2,244,726	210,334	1,951,468	31,456	44,400	-	7,068	22,071	-	16,414	5,227	70	-	359
54	2024	ARP-Printer Asset Management (PAM)	New Computers / Hardw	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. This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; 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 unneeded 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.	2024-01-01	2024-12-31	(1.00)	1,081,120	-		753,000	-	692,084	45,333	5,420	-	10,163	-	-	-	-	-	-	-

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 2024, 2025, 2026, and 2027
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
55	2024	ARP-Server and Storage	New Computers / Hardw	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. 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.	2024-01-01	2024-12-31	(1.00)	700,693	92,769		488,033	2,864	447,825	15,288	18,213	-	3,846	58,456	-	6,053	26,511	25,670	-	221
56	2024	ARP-Workstation Asset Management (WAM)	New Computers / Hardw	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 if 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.	2024-01-01	2024-12-31	(1.00)	5,992,992	28,216		4,174,119	-	3,993,657	154,595	2,035	-	23,832	17,776	-	530	218	4,854	-	12,175
57	2024	Data Center 2.0	New Computers / Hardw	IT/Digital Foundation	Prior period adjustment.							4	-	-	-	-	-	4	-	-	-	-	-	-	-
58	2024	Digital-Hybrid Cloud and Data Center Migration	New Computers / Hardw	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 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 Parnall 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 managed services 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 Grand Rapids Main co-location data center to become the primary data center for on-premises IT services; (2) demoting the Company's Parnall data center to the disaster recovery data center for on-premises IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premises to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying base infrastructure to allow each location (on-premises or in cloud) to function independently; (7) deploying cloud and on-premises 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. 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 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.	2023-02-01	2026-02-02	0.18	6,979,887	1,891,804		1,688,778	75,586	(66,731)	551,410	974,186	-	154,328	493,142	118,264	13,668	133,735	227,476	-	-
59	2024	SAP HANA Database Migration	New Computers / Hardw	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. The selected alternative to migrate the SAP databases to HANA prior to implementing S/4HANA gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process changes required with S/4HANA.	2023-04-24	2025-12-31	(0.76)	6,918,889	1,431,736		1,978,703	213,750	244,915	307,729	1,014,137	-	198,173	529,368	-	-	94,861	434,507	-	-
60	2024	2010 SharePoint Platform Replacement	Software(Intangible)	IT/Digital Foundation	Prior period adjustment.							-	-	-	-	-	-	-	58	-	-	-	-	-	58
61	2024	Application Currency-IT/Digital Foundation-Application Platforms-O&M	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.	2024-01-01	2026-12-31	(1.00)	-	245,902		-	-	-	-	-	-	-	154,919	-	-	23,054	131,864	-	-
62	2024	Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	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.	2024-01-01	2024-12-31	(1.00)	-	24,459		-	-	-	-	-	-	-	15,409	-	-	15,250	159	-	-

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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
63	2024	AxWay Secure Transport 2024 Upgrade	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.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.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	2025-03-03	(1.00)	-	75,858		-	-	-	-	-	-	-	-	47,789	-	43	3,523	26,597	17,627	-	-	-
64	2024	Cloud Virtual Desktop	Software(Intangible)	IT/Digital Foundation	Prior period adjustment.							-	-	-	-	-	-	-	1,065	-	-	1,054	11	-	-
65	2024	Digital-Cloud Data and Analytics Platform	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 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. 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	2025-02-24	(1.00)	12,368,529	1,259,815		6,286,958	250,482	82,373	771,811	4,901,184	-	281,108	609,327	(731)	-	119,343	547,750	-	2,965
66	2024	Enhancements-IT-Capital	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.	2024-01-01	2024-12-31	(1.00)	56,629	54		39,442	148	125	9,833	34	-	29,302	34	-	-	34	-	-	-
67	2024	Enhancements-IT-O&M	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.	2024-01-01	2024-12-31	(1.00)	-	3,697		-	-	-	-	-	-	-	2,329	-	-	116	2,213	-	-
68	2024	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 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.	2024-04-05	2024-12-31	(1.00)	626,812	84,906		436,575	-	8,666	21,826	400,777	-	5,305	53,491	-	-	9,737	43,753	-	-
69	2024	Enterprise Service Bus Application 2020-2021 Upgrade	Software(Intangible)	IT/Digital Foundation	Prior period adjustment.							232	-	-	190	-	-	42	-	-	-	-	-	-	-
70	2024	Enterprise Service Bus Application 2024-2025 Upgrade	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 in 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 more 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 mainstream 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.	2023-10-30	2025-12-26	(0.92)	-	741,105		-	-	-	-	-	-	-	-	-	-	-	-	6,823	1,479	-	-
71	2024	HR Support Pack and Business Software Inc Upgrade 2023	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.	2022-12-26	2024-01-22	-	-	1,495,902		-	-	-	-	-	-	-	11,119	-	-	1,978	9,141	-	-
72	2024	HR Support Pack and Business Software Inc Upgrade 2024	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.	2024-03-25	2024-12-08	-	-	527,820		-	-	-	-	-	-	-	332,527	-	-	52,508	280,018	-	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
73	2024	IT Operations Management - Service Operations	Software(Intangible)	IT/Digital Foundation	This project will implement an application service mapping tool to effectively manage business-critical services through identification of infrastructure components and application interactions. This tool automates the mapping process to create a complete, up-to-date, and accurate record of the mapped application service in the Database. Application service mapping works hand-in-hand with asset discovery, building on discovered infrastructure data to identify all the assets that support a service, and along with their service-specific relationships.As the IT systems steadily increases in complexity and evolve faster than the IT organization can respond to system issues in an optimized and cost-effective manner, the current configuration of the system does not provide the clarity needed in order to understand how the infrastructure interacts with the applications within the IT System it supports and in order to respond to emergent IT incidents in the most rapid and costs effective manner. These constraints can lead to lengthy response and implementation times; negligible or ineffective resolutions; reduced functionality; and elongated outage times in the infrastructure and applications in the system.This project will create value for the Company by mapping critical application services through discovery of the underlying infrastructure associated with application services and its relationship to parent business applications. Specifically, by creating application service maps, this project will: (1) increase visibility and understanding between Information Technology (IT) infrastructure and Configuration Items; (2) improve accuracy through real-time, automatically updated infrastructure and component changes; (3) reduce IT Subject Matter Experts time on emergent IT issues; (4) Utilize of IT Service Management processes; and (5) Reduce downtime by identifying dependences and impact analysis.The project scope includes: (1) implementation of On-Premise application service maps which have significant business impact; (2) establishment of process roles needed to support service maps built.Alternatives considered included: (1) Choose an alternate IT Operations Management System with Cloud capabilities. This alternative was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not chosen as there would be a correlation gap between application services and the underlying infrastructure and would not address the ever-increasing resolution costs. (4) Develop and implement an on-premises service mapping and process solution. This alternative was chosen due to the value in Information Technology (IT) Operations Management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can utilize the Configuration Management Database (CMDB) and work hand-in-hand with asset discovery.	2023-10-01	2024-03-09	(1.00)	3,012,243	699,524		139,403	-	-	3,908	96,617	-	38,878	41,492	-	-	959	40,533	-	-
74	2024	Nimbus Phase 5	Software(Intangible)	IT/Digital Foundation	Prior period adjustment.							(2,331)	(2,331)	-	-	-	-	-	-	-	-	-	-	-	-
75	2024	Operational Technology - Service Management Upgrade	Software(Intangible)	IT/Digital Foundation	This project will implement Operational Technology (OT) service management capabilities. Service management provides automated asset tracking, maintenance, and incident management for the assets.The Company' Internal Audit team conducted an audit of the Operational Technology (OT) asset environment and identified significant gaps in the patch management program. The patch management operating model is decentralized, has limited and inconsistent standards, doesn't have a company-wide governance structure to monitor all business areas of the Company and lacks a complete and accurate asset inventory. Due to the lack of a complete asset inventory, as well as a significant number of gaps identified in the patch management governance, operating model, processes, and controls to manage all assets within the Company's environment, an unknown magnitude of risk exists that critical patches were not installed timely, which could create the potential for increased security vulnerabilities.The project provides value to the Company in three ways 1.) Establishes a complete and accurate asset inventory. 2.) Creates a Company-wide governance structure with documented standards and processes to manage the assets and 3.) Defines a comprehensive patch management operating model with clearly defined roles and responsibilities.The project scope includes: (1) the implementation of an asset management tool (2) the implementation of an incident management tool, (3) and the establishment of process roles needed to support the assets.Alternatives considered included: (1) Choose a Cloud-based alternate asset management system. This option was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. Continue to manually track or not track Operational Technology (OT) Digital assets at the Company, which will not address the need to effectively track OT Digital assets and plan for their support. (4) Develop and implement an asset management and incident management tool and processes. This alternative ultimately chosen has strengths in Information Technology (IT) service management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can help bridge the gap between IT and OT, enable the Company to manage both types of assets through a single interface.	2023-10-01	2024-03-07	(1.00)	894,877	192,305		115,849	-	-	27,776	53,037	-	35,036	27,662	-	-	(1,159)	28,822	-	-
76	2024	Product Family Enhancements-Application Platforms Services-Capital	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.	2024-01-01	2024-12-31	(1.00)	389,420	7,949		271,231	20,678	5,305	135,661	68,189	-	41,398	5,008	-	-	4,969	39	-	-
77	2024	Product Family Enhancements-Application Platforms Services-O&M	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.	2024-01-01	2024-12-31	-	-	314,871		-	-	-	-	-	-	-	198,369	22,987	8,265	105,262	61,854	-	-
78	2024	Product Family Enhancements-Infrastructure Platforms Services-Capital	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.	2024-01-01	2024-12-31	(1.00)	547,715	79,958		381,483	272	87,027	155,245	101,410	-	37,530	50,374	5,681	8,333	21,736	14,624	-	-
79	2024	Product Family Enhancements-Infrastructure Platforms Services-O&M	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.	2024-01-01	2024-12-31	-	-	146,350		-	-	-	-	-	-	-	92,201	-	31,734	4,644	55,823	-	-
80	2024	Public Key Infrastructure (PKI) Upgrade	Software(Intangible)	IT/Digital Foundation	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.	2023-10-02	2025-03-03	(1.00)	1,388,095	272,379		859,646	99,456	339,468	152,651	174,214	-	93,856	118,408	(21,032)	116,420	12,661	10,359	-	-

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 2024, 2025, 2026, and 2027
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
81	2024	SAP Support Pack Upgrade 2023-2024	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 our 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), Governance, Risk and Compliance (GRC), 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) Divide 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) Migrate to SAP S/4HANA. This option was not selected at this time because it is part of the long-term digital plan and requires substantial planning and investment. (3) 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.	2023-10-30	2024-10-15	(1.00)	-	173,029		-	-	-	-	-	-	-	101,893	-	-	13,091	88,802	-	-
82	2024	Software Asset - Service Management Upgrade	Software(Intangible)	IT/Digital Foundation	This project will optimize the software asset management process by systematically monitor, assess and oversee software licenses and compliance using Software Asset Management Professional.The on-premises software asset management technology currently used in the Company lacks compatibility to automate license reclamation, cost optimization, and license forecasting. These software asset management constraints lead to the inability to optimize software license purchasing and effective license demand management.This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective software asset management processes and workflow. Specifically, by replacing the on-premise application, the project will: (1) streamline the software request workflow including license reclamation and software deployment; (2) help ensure compliance with software license agreements; (3) identify opportunities of license optimization leading to cost optimization; (4) mitigate risk related to software asset management; (5) optimize license forecasting and (6) increase asset visibility.The project scope includes: (1) the implementation of software asset management tool; (2) the establishment of processes and process roles needed to support the assets; and (3) retirement of the on-premise software asset management tool.Alternatives considered included: (1) Choose an alternate Cloud based asset management system. This alternative was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not selected as the current Software Asset Management tool that lacks integration and automation and will not address optimizing and effective management of licenses and purchases. (4) Develop and implement an on-premises Software Asset Management solution. This alternative ultimately chosen has strengths in software asset management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can helps license compliance, optimization and automation.	2023-06-01	2024-02-29	(0.80)	1,120,474	260,229		49,003	-	-	15,747	29,772	-	3,484	50,479	-	-	23,542	26,937	-	-
83	2024	Software Platform Refresh	Software(Intangible)	IT/Digital Foundation	The Software Platform Refresh project will upgrade server operating systems, hypervisors (virtual machine monitors), and databases to retain low-cost vendor support. For systems that go beyond their normal manufacturer support ending, there will be increased support and maintenance fees of 20% to 100% above current support and maintenance depending on vendor. Completing this project allows the organization to (1) avoid high support costs; (2) provide for system security; and (3) stay current to promote seamless interoperability among servers, applications, and databases. Aging servers are more susceptible to security vulnerabilities and performance issues that ultimately could affect the business and customers. The project will add value for the Company by: (1) avoiding costs for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring reliability and compliance with Information Security requirements; (3) improving data center environment stability; and (4) avoiding the need for high risk upgrades that cross multiple versions. The project scope includes: (1) upgrading operating systems and databases on servers that are near end of support with a given vendor; and (2) maintaining hypervisors at the current version for stability and performance. A funding options matrix was completed to review the potential alternatives. The alternatives identified were: (1) Complete the full scope of the solution for $1 million in order to eliminate the need for ongoing extended support; (2) Reduce the scale of the solution, which requires $1.6 million in ongoing extended support; (3) Reduce the scale of the solution even further, which requires $2.4 million in ongoing extended support; (4) Do not complete a software platform refresh, which requires $3.3 million in ongoing extended support. Alternative 1 was selected as the most cost-effective solution to ensure ongoing system stability; seamless integration; and mitigation of cyber-security risks without the significant cost of extended support necessary for end of life software systems.	2024-01-01	2024-12-31	(1.00)	-	90,647		-	-	-	-	-	-	-	57,107	36,862	-	13,493	6,752	-	-
84	2024	SolarWinds Performance Monitoring Expansion Upgrade	Software(Intangible)	IT/Digital Foundation	Prior period adjustment.							2,743	-	-	2,246	-	-	497	2,421	511	-	1,265	644	-	-
85	2024	Tibco API Exchange Gateway Replacement	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 TIBCO 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	2024-08-05	(1.00)	162,480	109,627		113,167	-	-	37,728	63,456	-	11,983	69,065	-	-	38,819	30,246	-	-
86	SUBTOTAL	**2024 IT/Digital Foundation**										**25,691,105**	**1,152,805**	**12,420,454**	**2,622,360**	**8,428,299**	**-**	**1,067,187**	**3,409,862**	**162,584**	**276,855**	**770,004**	**2,194,626**	**-**	**15,794**
87	2024	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 increased system vulnerabilities, and out-of-warranty repair costs.	2024-01-01	2024-12-31	(1.00)	445,156	18,840		238,648	51,749	171,348	10,686	1,857	-	3,008	11,869	-	7,012	4,643	214	-	-
88	2024	ARP-Physical Security	New Computers / Hardw	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 concerns, incident 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.	2024-01-01	2024-12-31	(1.00)	2,281,985	14,060		1,589,402	-	1,295,170	4,242	456,852	-	(166,862)	8,858	-	-	8,828	30	-	-
89	2024	Radar Intrusion Detection	New Computers / Hardw	Security	Prior period adjustment.							(15,596)	-	(16,741)	-	1,145	-	-	-	-	-	-	-	-	-
90	2024	Application Currency-Security-Capital	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, (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.	2024-01-01	2024-12-31	(1.00)	-	836		-	-	-	-	-	-	527	334	193	-	-	-	-	-
91	2024	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, (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.	2024-01-01	2024-12-31	-	-	9,482		-	-	-	-	-	-	-	5,974	-	-	5,967	6	-	-

Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
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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)	(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
92	2024	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.	2024-01-01	2024-12-31	(1.00)	411,984	36,541		286,947	340,942	5,905	7,388	(72,699)	-	5,381	23,021	7,709	-	14,249	1,062	-	-
93	2024	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: ( ) 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.	2024-01-01	2024-12-31	-	-	590,009		-	-	-	-	-	-	-	371,706	27,252	36,887	223,154	84,595	-	(181)
94	2024	Nerc Cip version 5	Software(Intangible)	Security	Prior period adjustment.							(2,172)	-	-	-	-	-	(2,172)	-	-	-	-	-	-	-
95	2024	Saviynt Enterprise Identity Governance and Access (EIGA) Implementation	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.	2023-11-27	2025-05-30	(1.00)	5,641,435	750,051		1,946,412	1,336,721	-	251,695	233,215	-	124,581	148,748	82,932	-	18,089	47,582	-	146
96	2024	Security Analytics	Software(Intangible)	Security	Prior period adjustment.							-	-	-	-	-	-	-	18	-	-	18	-	-	-
97	SUBTOTAL	2024 Security										4,043,641	1,729,412	1,455,682	274,212	628,491	-	(36,065)	575,720	118,227	44,094	274,945	133,489	-	(36)
98	TOTAL	2024										44,022,631	7,315,565	15,212,662	5,640,767	13,730,490	-	2,123,236	7,475,848	459,948	354,623	1,947,432	4,976,962	-	(262,017)
99	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 contracts, 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.	2025-04-01	2026-05-01	-	-	549,012		-	-	-	-	-	-	-	191,008	-	-	80,023	98,489	12,496	-
100	2025	Application Currency-Corporate-Capital	Software(Intangible)	Corporate	The Corporate Services 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 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 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)	57,310	5,350	ROM	39,297	-	34,285	3,429	-	213	1,371	3,316	-	-	3,099	-	217	-
101	2025	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, (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 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	-	-	340,320		-	-	-	-	-	-	-	210,932	-	-	197,132	-	13,799	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
102	2025	Asset Accounting Upgrade 2025-2026	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 PowerPlan, 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.	2025-02-01	2026-01-31	(1.00)	-	624,318		-	-	-	-	-	-	-	345,790	-	-	92,334	-	253,456	-
103	2025	Product Family Enhancements-Corporate-Capital	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)	3,848,634	552,239		2,639,008	-	-	1,702,324	27,428	148,510	760,746	342,281	-	-	305,770	14,119	22,392	-
104	2025	Product Family Enhancements-Corporate-O&M	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)	-	520,325		-	-	-	-	-	-	-	322,500	-	-	301,402	-	21,098	-
105	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. 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.	2023-02-27	2025-11-21	(1.00)	832,903	479,821		377,889	-	-	119,997	171,425	20,400	66,067	59,470	-	-	30,990	21,693	6,787	-
106	2025	20% ROM Adjustment - Corporate	Software(Intangible)	Corporate	This is for the 20% ROM Adjustment for IT projects.							(7,859)	-	(6,857)	(686)	-	(43)	(274)	-	-	-	-	-	-	-
107	**SUBTOTAL**	**2025 Corporate**										**3,048,336**	**-**	**27,428**	**1,825,064**	**198,853**	**169,080**	**827,911**	**1,475,296**	**-**	**-**	**1,010,749**	**134,301**	**330,245**	**-**
108	2025	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, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the 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.	2025-01-01	2025-12-31	-	-	9,564		-	-	-	-	-	-	-	5,928	-	-	5,540	-	388	-
109	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.	2025-04-11	2026-08-28	(1.00)	4,021,500	936,250	ROM	1,654,526	-	-	462,848	617,130	75,598	498,950	348,175	-	-	139,456	185,942	22,778	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
110	2025	Energy Assistance Enhancements and Maintenance Annual Updates	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	-	-	311,528		-	-	-	-	-	-	-	193,086	-	-	165,087	15,368	12,632	-
111	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.	2024-07-02	2025-06-30	(0.80)	-	231,867		-	-	-	-	-	-	-	50,475	-	-	27,700	13,079	9,695	-
112	2025	Product Family Enhancements-Customer-Capital	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)	7,710,995	856,958		5,287,430	-	-	2,526,370	1,433,606	168,081	1,159,372	531,147	-	-	454,232	30,638	46,277	-
113	2025	Product Family Enhancements-Customer-O&M	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)	-	406,621		-	-	-	-	-	-	-	252,026	-	-	156,044	50,834	14,370	30,778
114	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	-	-	297,944		-	-	-	-	-	-	-	184,667	-	-	172,586	-	12,081	-
115	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.	2025-04-03	2026-02-23	(1.00)	116,432	245,030	ROM	79,837	-	-	52,113	-	3,648	24,076	151,871	-	-	141,935	-	9,935	-
116	2025	20% ROM Adjustment - Customer	Software(Intangible)	Customer	This is for the 20% ROM Adjustment for IT projects.							(346,873)	(123,426)	-	(102,992)	-	(15,849)	(104,605)	-	-	-	-	-	-	-
117	**SUBTOTAL**	**2025 Customer**										**6,674,920**	**(123,426)**	**-**	**2,938,338**	**2,050,736**	**231,478**	**1,577,793**	**1,717,375**	**-**	**-**	**1,262,581**	**295,861**	**128,156**	**30,778**
118	2025	Ransomware Recovery-OT-Electric & Generation	New Computers / Hardw	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 (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 r the regulatory ramifications such action would result in.(2) Restoring from tape is a possibility but significantly increases OT estoration 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.	2025-02-10	2025-12-31	(1.00)	5,515,728	142,629		218,659	-	-	108,800	45,917	10,830	53,112	108,912	77,308	-	27,200	2,500	1,904	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
119	2025	Application Currency-Electric-Capital	Software(Intangible)	Electric	The Electric/Generation/Renewables Engineering and 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/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.	2025-01-01	2025-12-31	(1.00)	43,860	-	ROM	43,860	-	-	30,000	-	2,100	11,760	-	-	-	-	-	-	-
120	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'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	-	-	199,126		-	-	-	-	-	-	-	199,126	-	-	185,719	-	13,407	-
121	2025	Cascade Modernization and Prioritization	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.	2024-10-17	2025-10-10	(1.00)	373,801	51,473		86,495	18,360	-	38,600	9,000	2,702	17,833	30,145	-	-	23,500	5,000	1,645	-
122	2025	Catastrophic Crewing (CatCrew) Version 2.0	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.	2024-10-21	2025-11-14	5.02	2,421,749	310,938	ROM	1,199,380	-	-	728,000	-	50,960	420,420	194,740	-	-	182,000	-	12,740	-
123	2025	Electric Geographic Information System (GIS) Design Platform Modernization	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.	2026-02-24	2029-02-22	(0.31)	6,138,677	688,999	ROM	1,431,615	-	200,000	526,511	425,000	36,856	243,248	244,417	-	70,000	92,913	75,000	6,504	-
124	2025	Forestry System Conversion And Update	Software(Intangible)	Electric	This project will modernize the Forestry systems to take advantage of modern technology that will enable a reduction in human struggle by providing improved work management solution. Forestry is currently utilizing MS Access and Excel to support their system-wide program workflow management, contractor invoicing, and data storage, this has resulted in highly specialized daily manual processes, limitations in automation opportunities, data inconsistencies, and lagged productivity reporting causing waste. This system is not supported by IT and is vulnerable to security risks and ancestral knowledge loss. In addition, the current system does not tie in effective work management processes or Vegetation Management analytics. In its current condition, not only is this product lacking durable support, it is also extremely difficult to avail itself of modern Machine Learning techniques, resulting in a system that is not flexible to the ever-changing business needs or advancement in technology to aid the business. Lastly, the target condition would include modern methods for authentication for all contractor groups. Modernize the Forestry work planning, execution, and payment processes. Centralize and provide an updated user interface for all Forestry work planning. Provide workflows for internal Foresters and external vendors. Improve invoicing processes and provide workflow to expedite and report financial metrics while adhering to compliance . All work auditing processes will be improved along with approvals and exception reporting for CE foresters. Centralized Forestry work plan, status and billing data that has a single source of truth to aid in determining Forestry strategic objectives and deliver real-time reporting capabilities. Lastly, the solution would enable the standardization for LCP location definitions and provide centralized vendor access and provide analytics capabilities to assist in prioritizing work. The project would replace the current system with a solution that would support an updated database, improved work management processes, ability leverage in place enterprise Asset Management tools while providing fiscal intelligence on spend, pay back, repeat visits, maintenance plans. Additionally, leverage real-time data Analytics for vegetation management and work priorities while improving work assignment capabilities and storm support. The solution would have the capability to Automatically route approvals of vendor invoices. Provide for external contractors to administer work assignments and return invoices through a secured log-in. Several alternatives have been considered they include the following: 1) Leaving the homegrown Access database in place and working to improve it. This option was not chosen because of the significant risk associated with an older application not supported by IT. 2) The next option is the option pursue an entirely COTS (Custom Off-the Shelf) solution by an industry leader in the Forestry space. The options are numerous and the technology in this discipline has evolved, but does not provide long-term flexibility. 3) Implementing an IT supported hybrid solution of an off-the-shelf work management component with custom built predictive analytics capabilities. This is the preferred option, and will provide a more targeted fit for the forestry organizations requirements.	2025-11-03	2026-08-04	(1.00)	2,502,600	214,000	ROM	2,502,600	950,000	-	975,000	-	68,250	509,350	214,000	-	-	100,000	100,000	14,000	-

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 2024, 2025, 2026, and 2027
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
125	2025	Generation Operations Digital Work Management	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.Â (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.	2023-10-30	2025-12-30	(1.00)	1,224,960	69,750		1,151,479	225,345	-	610,832	124,500	22,120	168,682	65,260	42,389	-	-	21,185	1,106	-
126	2025	HVD SCADA Upgrade	Software(Intangible)	Electric	The Electric High Voltage Distribution Monitoring System Upgrade project upgrades the software and hardware components of the High Voltage Distribution 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 risk 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.	2025-03-17	2026-05-05	(1.00)	2,820,400	567,205	ROM	2,317,208	250,000	1,700,000	94,000	100,000	12,880	160,328	146,545	-	100,000	43,500	-	3,045	-
127	2025	Product Family Enhancements-Electric-Capital	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.	2025-01-01	2025-12-31	(1.00)	2,187,965	274,361		2,187,965	-	26,000	1,109,279	195,000	283,387	574,299	274,361	-	874	107,000	91,000	75,487	-
128	2025	Product Family Enhancements-Electric-O&M	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 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.	2025-01-01	2025-12-31	(1.00)	-	254,774		-	-	-	-	-	-	-	254,774	3,255	728	216,526	17,877	16,387	-
129	2025	Streetlight Outage and Restoration Optimization	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 80% 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 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.	2025-03-03	2025-08-14	(0.99)	1,785,442	238,155	ROM	1,785,442	-	-	943,500	340,000	66,045	435,897	238,155	-	-	166,500	60,000	11,655	-
130	2025	Transmission Outage Application (TOA) Upgrade	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 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 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.	2025-02-28	2025-11-01	(0.93)	959,795	64,621	ROM	959,795	180,000	-	143,284	538,600	10,030	87,881	64,621	-	-	23,141	39,860	1,620	-
131	2025	20% ROM Adjustment - Electric	Software(Intangible)	Electric	This is for the 20% ROM Adjustment for IT projects.							(2,047,980)	(276,000)	(380,000)	(668,059)	(280,720)	(49,424)	(373,777)							
132	**SUBTOTAL**	**2025 Electric**										**11,836,517**	**1,347,705**	**1,546,000**	**4,619,747**	**1,497,297**	**516,735**	**2,309,033**	**2,035,056**	**123,552**	**171,603**	**1,167,999**	**412,462**	**155,500**	-

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 2024, 2025, 2026, and 2027
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)	(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
133	2025	Application Currency-Electric & Gas Shared-Capital	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, (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 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.	2025-01-01	2025-12-31	(1.00)	123,100	184,309	ROM	84,410	-	34,285	34,285	-	15,840	-	114,235	-	-	106,761	-	7,474	-
134	2025	Application Currency-Electric & Gas Shared-O&M	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 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.	2025-01-01	2025-12-31	-	-	461,888	-	-	-	-	-	-	-	286,281	-	-	260,073	8,002	18,205	-
135	2025	Application Currency-Operational Technology-O&M	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)	-	96,282	-	-	-	-	-	-	-	59,676	-	-	50,637	-	9,039	-
136	2025	Product Family Enhancements-Electric & Gas Shared-Capital	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)	848,304	65,300		581,682	-	24,685	68,779	242,052	18,514	227,652	40,473	-	1,550	14,256	22,933	1,735	-
137	2025	Product Family Enhancements-Electric & Gas Shared-O&M	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 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)	-	171,815		-	-	-	-	-	-	-	106,492	-	1,539	89,871	8,002	7,079	-
138	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; 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.	2023-12-04	2025-11-01	(1.00)	2,868,762	125,527		489,535	-	-	137,140	246,852	26,879	78,664	66,319	-	-	24,792	37,188	4,339	-
139	2025	20% ROM Adjustment - Electric & Gas Shared	Software(Intangible)	Electric & Gas Shared	This is for the 20% ROM Adjustment for IT projects.							(16,882)	-	(6,857)	(6,857)	-	(3,168)	-	-	-	-	-	-	-	-
140	**SUBTOTAL**	**2025 Electric & Gas Shared**										**1,138,745**	**-**	**52,113**	**233,347**	**488,994**	**58,065**	**306,316**	**673,476**	**-**	**3,088**	**546,391**	**76,126**	**47,871**	**-**

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 2024, 2025, 2026, and 2027
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
141	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.Â This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel.Â 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 7-year lifecycle basis.Â Cellular modems are refreshed on a 5-year life cycle basis.Â 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.Â 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)	2,940,332	114,491		1,522,210	-	1,199,902	42,172	243,286	19,962	16,899	70,962	-	40,597	20,281	8,097	1,986	-
142	2025	Application Currency-IT/Digital Foundation-Application Platforms-Capital	New Computers / Hardw. 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 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 alternatives 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)	48,246	20,335	ROM	33,082	-	-	22,628	-	1,584	8,870	12,604	-	-	10,695	-	1,909	-
143	2025	ARP-Collaboration	New Computers / Hardw. 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.Â 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.Â 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)	1,185,835	226,189		813,127	-	715,635	59,436	32,764	5,292	-	140,193	-	42,767	42,014	49,039	6,373	-
144	2025	ARP-Field Device Asset Management (FDAM)	New Computers / Hardw. 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.Â 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)	3,249,513	5,000		2,228,191	-	2,172,954	37,576	-	2,630	15,031	3,099	-	3,099	-	-	-	-
145	2025	ARP-Operational Technology Support Common	New Computers / Hardw. 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 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 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 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)	259,667	6,675		178,053	-	169,139	6,857	-	460	1,577	4,137	1,550	930	1,550	-	108	-
146	2025	ARP-Operational Technology Support Electric	New Computers / Hardw. 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)	55,750	3,070		55,750	-	46,000	7,500	-	525	1,725	3,070	1,000	1,000	1,000	-	70	-
147	2025	ARP-Printer Asset Management (PAM)	New Computers / Hardw. 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.Â 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.Â (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 unneeded 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)	1,520,905	5,000		1,042,885	-	1,013,149	20,228	-	1,416	8,091	3,099	-	3,099	-	-	-	-
148	2025	ARP-Workstation Asset Management (WAM)	New Computers / Hardw. 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)	8,680,563	89,935		5,952,282	-	5,646,692	144,683	86,810	16,204	57,873	55,742	-	52,912	2,645	-	185	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
149	2025	Digital-Hybrid Cloud and Data Center Migration	New Computers / Hardw	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.	2023-02-01	2025-12-01	0.24	6,979,887	1,891,804		1,217,947	123,426	-	709,453	-	101,287	283,781	359,615	-	-	294,383	-	20,607	44,626
150	2025	SAP HANA Database Migration	New Computers / Hardw	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 S4/HANA, 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 S4/HANA. A direct migration to S4/HANA 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 S4/HANA. 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 S4/HANA. This alternative was not selected because an S4/HANA SaaS migration is a much more disruptive option as the Company's business processes must be adjusted to accommodate functionality differences between ECC and S4/HANA. 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 S4/HANA. 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 S4/HANA.	2023-04-24	2025-11-01	(0.76)	6,918,889	1,431,736		1,156,358	-	-	126,364	865,238	60,567	104,190	254,511	-	-	97,309	140,551	16,650	-
151	2025	20% ROM Adjustment - IT/Digital Foundation	New Computers / Hardw	IT/Digital Foundation	This is for the 20% ROM Adjustment for IT projects.							(6,616)	-	-	(4,526)	-	(317)	(1,774)	-	-	-	-	-	-	-
152	2025	Application Currency-IT/Digital Foundation-Application Platforms-O&M	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)	-	90,874		-	-	-	-	-	-	-	56,324	-	-	47,792	-	8,532	-
153	2025	Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	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)	-	18,932		-	-	-	-	-	-	-	11,734	-	-	9,957	-	1,777	-
154	2025	Data & Analytics Platform Rationalization	Software(Intangible)	IT/Digital Foundation	This project will optimize the Data & Analytics system landscape by creating connections, migrating data into Data Lake 2.0 (DL 2.0), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems including SingleStore Data Lake (SSDL), SAP Business Warehouse (BW), SAP Business Objects (BOBJ), Native HANA, the BW Portal, and SAP Business Objects Data Services (BODS) creates value by reducing the total cost of ownership associated with maintaining and supporting legacy systems. 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.	2025-04-28	2026-08-14	0.22	10,002,200	1,660,500	ROM	2,147,612	68,570	-	685,700	1,028,550	47,999	316,793	221,270	-	-	61,981	154,951	4,339	-
155	2025	Enterprise Service Bus Application 2024-2025 Upgrade	Software(Intangible)	IT/Digital Foundation	This project will upgrade and migrate the Business Works developer application to the next version and other products used for the Enterprise Service Bus including Enterprise Messaging System, Business Events, Hawk Monitoring and Rendevouz 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. 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.	2023-10-30	2025-12-26	(0.92)	-	741,105		-	-	-	-	-	-	-	451,173	-	-	421,657	-	29,516	-
156	2025	HR Support Pack and Business Software Inc Upgrade 2025	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.	2024-12-30	2026-01-23	-	-	642,420		-	-	-	-	-	-	-	398,175	-	-	60,325	313,688	26,181	(2,019)

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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)	(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
157	2025	Iron Enterprise Edition 2025 Upgrade	Software(Intangible)	IT/Digital Foundation	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. Alternatives considered included: (1) Defer the upgrade. This alternative was not selected because it would decouple Iron EE (CE'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 use, creating more expense to support and no ability to leverage updated tool capability. (2) Replace the platform. Replacing IEE/MDM would require the application business owners to underitake a new initiative mirroring the expense and effort that went into the multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform the upgrade. This option is superior for both our customers and our Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Iron products.	2025-08-12	2026-05-20	(1.00)	383,000	495,279		-	-	-	-	-	-	-	76,218	-	-	71,232	-	4,986	-
158	2025	Product Family Enhancements-Application Platforms Services-Capital	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)	955,650	132,106		655,290	-	-	377,068	68,570	31,195	178,457	81,880	-	-	34,182	35,297	12,402	-
159	2025	Product Family Enhancements-Application Platforms Services-O&M	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	-	-	270,211		-	-	-	-	-	-	-	167,478	-	-	142,109	-	25,369	-
160	2025	Product Family Enhancements-Infrastructure Platforms Services-Capital	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)	1,094,270	148,589		750,341	-	-	459,379	41,142	35,037	214,784	92,096	-	-	56,969	21,178	13,949	-
161	2025	Product Family Enhancements-Infrastructure Platforms Services-O&M	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	-	-	131,147		-	-	-	-	-	-	-	81,286	-	-	68,973	-	12,313	-
162	2025	SAP S/4HANA Implementation	Software(Intangible)	IT/Digital Foundation	[redacted]																				

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
163	2025	Software Platform Refresh	Software(Intangible)	IT/Digital Foundation	The Software Platform Refresh project will upgrade server operating systems, hypervisors (virtual machine monitors), and databases to retain low-cost vendor support. For systems that go beyond their normal manufacturer support ending, there will be increased support and maintenance fees of 20% to 100% above current support and maintenance depending on vendor. Completing this project allows the organization to (1) avoid high support costs; (2) provide for system security; and (3) stay current to promote seamless interoperability among servers, applications, and databases. Aging servers are more susceptible to security vulnerabilities and performance issues that ultimately could affect the business and customers. The project will add value for the Company by: (1) avoiding costs for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring reliability and compliance with Information Security requirements; (3) improving data center environment stability; and (4) avoiding the need for high risk upgrades that cross multiple versions. The project scope includes: (1) upgrading operating systems and databases on servers that are near end of support with a given vendor; and (2) maintaining hypervisors at the current version for stability and performance. A funding options matrix was completed to review the potential alternatives. The alternatives identified were: (1) Complete the full scope of the solution for $1 million in order to eliminate the need for ongoing extended support; (2) Reduce the scale of the solution, which requires $1.6 million in ongoing extended support; (3) Reduce the scale of the solution even further, which requires $2.4 million in ongoing extended support; (4) Do not complete a software platform refresh, which requires $3.3 million in ongoing extended support. Alternative 1 was selected as the most cost effective solution to ensure ongoing system stability; seamless integration; and mitigation of cyber-security risks without the significant cost of extended support necessary for end of life software systems.	2026-01-01	2026-12-31	(1.00)	-	106,267		-	-	-	-	-	-	-	65,865	-	-	61,556	-	4,309	-
164	2025	20% ROM Adjustment - IT/Digital Foundation	Software(Intangible)	IT/Digital Foundation	This is for the 20% ROM Adjustment for IT projects							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
165	**SUBTOTAL**	**2025 IT/Digital Foundation**										[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
166	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) upgrading or replacing 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) upgrading or replacing 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) upgrading or replacing 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)	283,150	25,000		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
167	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) upgrading or replacing 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) upgrading or replacing 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) upgrading or replacing 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)	74,865	5,028		74,865	-	66,968	4,000	1,885	412	1,600	5,028	-	900	3,858	-	270	-
168	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 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) to continue operating 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 of hardware failure and not having vendor support, software bug fixes, security updates, and other software fixes.	2025-01-01	2025-12-31	(1.00)	1,281,598	111,430		663,483	-	570,823	44,004	26,144	4,910	17,602	69,065	-	3,409	44,006	17,355	4,295	-
169	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 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) to continue operating 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 of hardware failure and not having vendor support, software bug fixes, security updates, and other software fixes.	2025-01-01	2025-12-31	(1.00)	424,853	23,505		424,853	68	387,929	20,400	6,419	1,877	8,160	23,505	-	9,595	13,000	-	910	-
170	2025	ARP-Physical Security	New Computers / Hardw	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 concerns, incident 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)	1,625,400	12,626		1,114,537	-	685,014	82,284	308,565	38,673	-	7,826	-	-	4,834	2,479	512	-
171	2025	Security/OT Field Modernization	New Computers / Hardw	Security	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 chose to deploy a dedicated OT laptop and communications circuits.	2025-03-07	2026-03-01	(1.00)	1,161,568	305,600	ROM	572,641	-	195,287	233,961	-	16,377	127,015	121,234	21,693	-	-	-	-	99,541
172	2025	20% ROM Adjustment - Security	New Computers / Hardw	Security	This is for the 20% ROM Adjustment for Security projects.							(114,528)	-	(39,057)	(46,792)	-	(3,275)	(25,403)	-	-	-	-	-	-	-
173	2025	Application Currency-Security-Capital	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, (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)	146,200	4,622	ROM	100,249	-	-	68,570	-	31,679	-	2,865	-	-	2,431	-	434	-
174	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 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, (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	-	-	145,757		-	-	-	-	-	-	-	90,341	-	-	76,656	-	13,684	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
175	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)	1,598,988	99,967		1,096,426	192,400	16,678	349,924	152,854	384,570	-	61,960	-	-	4,504	31,903	25,554	-
176	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, 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	-	-	373,815		-	-	-	-	-	-	-	231,693	7,145	-	206,518	4,142	13,888	-
177	2025	Saviynt Enterprise Identity Governance and Access (EIGA) Implementation	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.	2023-11-27	2025-05-30	(1.00)	5,641,435	750,051		1,303,074	-	68,570	211,196	754,270	94,942	174,096	279,120	123,961	-	87,083	-	6,096	61,980
178	2025	20% ROM Adjustment - Security	Software(Intangible)	Security	This is for the 20% ROM Adjustment for Security projects.							(20,050)	-	-	(13,714)	-	(6,336)	-	-	-	-	-	-	-	-
179	**SUBTOTAL**	**2025 Security**										**5,362,137**	**192,468**	**2,078,252**	**966,776**	**1,251,172**	**564,809**	**308,662**	**908,131**	**152,799**	**13,904**	**457,300**	**55,878**	**66,728**	**161,521**
180	**TOTAL**	**2025**										[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
181	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 (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.	2025-04-01	2026-05-01	-	-	549,012		-	-	-	-	-	-	-	149,273	-	-	64,634	84,639	-	-
182	2026	Application Currency-Corporate-Capital	Software(Intangible)	Corporate	The Corporate Services 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 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, (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 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)	137,544	12,840	ROM	94,314	-	82,284	8,228	-	267	3,534	7,958	-	-	7,438	-	521	-
183	2026	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, (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 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)	-	309,502		-	-	-	-	-	-	-	191,831	-	-	179,281	-	-	12,550

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
184	2026	Asset Accounting Upgrade 2025-2026	Software(Intangible)	Corporate	The project will upgrade our 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 on an undisclosed timeline. 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; (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 PowerPlan, 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) Analyze and go to cloud possibilities (4) wait until a future upgrade cycle; (5) 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.	2025-02-01	2026-01-31	(1.00)	-	624,318		-	-	-	-	-	-	-	41,165	-	-	7,694	-	-	33,471
185	2026	Product Family Enhancements-Corporate-Capital	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 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)	2,121,463	311,453		1,454,687	-	-	949,535	-	66,467	438,685	193,040	-	-	180,411	-	12,629	-
186	2026	Product Family Enhancements-Corporate-O&M	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 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)	-	188,010		-	-	-	-	-	-	-	116,530	-	-	108,906	-	7,623	-
187	2026	Self Service Vendor Portal	Software(Intangible)	Corporate	The work will create an external portal for vendors to exercise self-service features to streamline and automate purchase order and invoice management and improve visibility to invoice and payment status. For Accounts Payable, vendors must repeatedly interact with the Company through multiple channels to ask questions, submit invoices, or check invoice or payment status, including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates, to make payments, or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for vendor invoice and payment management and lacks the ability for vendors to utilize touchless invoice creation from POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 6 contracted resources, and creates the potential for late payments or missing early payment discounts. For Supply Chain, vendors must repeatedly interact with the Company through multiple channels to ask questions, update POs (quantities, costs, shipping dates) including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for updates to the POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 4 employee resources. This also creates the potential for late payments, missing early payment discounts, delays in receiving due to lack of shipping notifications from vendors, delays to scheduled work due to lack of acknowledgement and lead time adherence, and the inability to enforce contractual obligations. This project creates value for the Company by: (1) creating self-service functionality/increasing touchless invoice creation/processing that allows the vendor to select items from a purchase order to create an invoice on demand; (2) providing vendors with real-time invoice and payment status, increasing employee productivity by eliminating waste (3) allow self-service updates of vendor master data (banking info, remittance info, etc.) (4) fewer late payments by vendors thus reducing Company follow up and tracking; (5) creating better visibility for vendors to take advantage of early payment discounts thus reducing related vendor inquiries; (6) reducing vendor questions related to invoice and purchase orders through self-service functions and portal information; (7) reducing the cost per invoice; (8) creating self-service functionality/increasing touchless PO creation/processing that allows the vendor to select items from a purchase order to update quantities, costs, and shipping dates; (9) providing vendors with real-time PO information, increasing employee productivity by eliminating waste; and (10) fewer late deliveries by vendors thus reducing Company follow up and tracking. The project scope includes: (1) submit an RFP for a vendor portal solution and implementation; (2) configure ability for vendors to more efficiently and more accurately self-submit invoices and POs electronically; (3) configure ability for vendors to self-convert items on a purchase order to an invoice; (4) configure ability for vendors to view invoice and payment status; (5) configure ability for vendors to make changes to SAP master data, including PO line item details; (6) configure ability to offer/process dynamic discounting (7) create new reports and dashboards; (8) enabling method to validate vendors should have access to the portal and removing access when appropriate; (9) configure ability for vendors to make self-serve changes to shipping status and delivery dates; and (10) integration to vendor invoice management system and SAP. Alternatives considered include: (1) Continue use of the current manual processes which results in waste and inefficiencies for employees and vendors. This could also result in late payments and lost discounts for vendors; (2) Build a custom solution. This option was not selected as the Company has a vendor portal, that is only leveraged for vendors to ask questions. As well, it doesn't leverage best practices; (3) Building a combination of custom and standard integration to existing solutions. This option was not selected because it doesn't follow industry best practices; (4) expand our current vendor portal. This option was not chosen due to limited functionality and not matching capability roadmaps; and (5) implement a new SaaS solution specific to a vendor portal experience. Option (5) is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation to vendors via real-time processing.	2026-03-01	2026-08-01	1.13	134,816	489,600	ROM	92,443	-	-	60,342	-	4,224	27,878	79,583	-	-	24,792	49,584	5,206	-
188	2026	20% ROM Adjustment - Corporate	Software(Intangible)	Corporate	This is for the 20% ROM Adjustment for IT projects							(37,351)	-	(16,457)	(13,714)	-	(898)	(6,282)	-	-	-	-	-	-	-
189	**SUBTOTAL**	**2026 Corporate**										**1,604,093**	**-**	**65,827**	**1,004,391**	**-**	**70,060**	**463,815**	**779,380**	**-**	**-**	**573,157**	**134,224**	**25,979**	**46,021**
190	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, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the 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)	-	165,139		-	-	-	-	-	-	-	102,354	-	-	95,658	-	6,696	-

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 2024, 2025, 2026, and 2027
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
191	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 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 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 ServicedBench 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.	2025-04-11	2026-08-28	(1.00)	4,021,500	936,250	ROM	1,103,017	-	-	308,585	411,430	-	383,032	232,117	-	-	92,971	123,961	-	15,185
192	2026	Energy Assistance Enhancements and Maintenance Annual Updates	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 Enhancements 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 LEAP 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 dollars 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	-	-	311,528		-	-	-	-	-	-	-	193,086	-	-	165,087	15,368	-	12,632
193	2026	Product Family Enhancements-Customer-Capital	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 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)	3,806,948	198,920		2,610,424	-	6,162	682,167	1,544,945	74,525	302,626	123,292	-	-	85,185	30,892	7,214	-
194	2026	Product Family Enhancements-Customer-O&M	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 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)	-	279,082		-	-	-	-	-	-	-	172,976	-	-	103,103	58,557	11,316	-
195	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 the Michigan Public Service Commission (MPSC) rate change requirements, there is a need to make periodic updates/additions 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.	2027-01-01	2027-12-31	-	-	297,944		-	-	-	-	-	-	-	184,667	-	-	172,586	-	-	12,081
196	2026	20% ROM Adjustment - Customer	Software(Intangible)	Customer	This is for the 20% ROM Adjustment for IT projects.							(220,603)	-	-	(61,733)	(82,284)	-	(76,606)		-	-	-	-	-	-
197	**SUBTOTAL**	**2026 Customer**										**3,492,838**	**-**	**6,162**	**929,019**	**1,874,091**	**74,525**	**609,052**	**1,008,493**	**-**	**-**	**714,589**	**228,779**	**25,227**	**39,898**
198	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 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)	-	306,300		-	-	-	-	-	-	-	306,300	-	-	283,941	2,483	-	19,876

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
199	2026	Catastrophic Crewing (CatCrew) Version 2.0	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 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. 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. 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. 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.	2024-10-21	2026-03-14	2.93	2,421,749	310,938	ROM	527,200	-	-	320,000	-	-	207,200	85,600	-	-	80,000	-	-	5,600
200	2026	Electric Geographic Information System (GIS) Design Platform Modernization	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 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.	2026-02-24	2029-02-22	(0.48)	6,138,677	688,999	ROM	1,109,865	-	-	724,455	-	50,712	334,698	136,794	-	-	127,845	-	8,949	-
201	2026	HVD SCADA Upgrade	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.	2025-03-17	2026-05-05	(1.00)	2,820,400	567,205	ROM	503,192	-	-	156,000	250,000	-	97,192	210,660	70,000	100,000	28,000	-	-	12,660
202	2026	Product Family Enhancements-Electric-Capital	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 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	2026-12-31	(1.00)	1,597,161	242,126		1,597,161	-	837	883,577	214,339	117,077	381,331	242,126	-	-	96,042	130,244	15,840	-
203	2026	Product Family Enhancements-Electric-O&M	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 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	2026-12-31	(1.00)	-	240,811		-	-	-	-	-	-	-	240,811	-	-	191,760	33,297	15,754	-
204	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.	2026-04-01	2027-04-30	(1.00)	1,476,795	170,130	ROM	1,000,374	-	-	576,904	-	-	423,470	114,107	-	-	102,977	-	-	11,130
205	2026	20% ROM Adjustment - Electric	Software(Intangible)	Electric	This is for the 20% ROM Adjustment for IT projects							(628,126)	-	-	(355,472)	(50,000)	(22,756)	(199,898)	-	-	-	-	-	-	-
206	**SUBTOTAL**	**2026 Electric**										**4,109,666**	**-**	**837**	**2,305,464**	**414,339**	**145,032**	**1,243,993**	**1,336,398**	**70,000**	**100,000**	**910,565**	**166,024**	**40,543**	**49,266**

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 2024, 2025, 2026, and 2027
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)	(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
207	2026	Application Currency-Electric & Gas Shared-Capital	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, (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 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.	2026-01-01	2026-12-31	(1.00)	82,135	309,420	ROM	42,606	-	-	29,142	-	-	13,464	191,780	15,719	171,087	4,649	-	-	325
208	2026	Application Currency-Electric & Gas Shared-O&M	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.	2026-01-01	2026-12-31	(1.00)	-	512,017		-	-	-	-	-	-	-	317,351	-	-	290,851	6,463	-	20,036
209	2026	Application Currency-Operational Technology-Capital	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 and respective databases, (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 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)	176,844	55,469	ROM	121,262	-	-	82,942	-	-	38,320	34,380	-	-	32,131	-	-	2,249
210	2026	Application Currency-Operational Technology-O&M	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 databases, (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 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)	-	305,316		-	-	-	-	-	-	-	189,236	-	-	176,856	-	-	12,380
211	2026	Product Family Enhancements-Electric & Gas Shared-Capital	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. 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.	2026-01-01	2026-12-31	(1.00)	1,036,665	155,294		710,841	-	6,857	95,116	492,792	41,154	74,922	96,252	-	2,899	10,396	76,850	6,107	-
212	2026	Product Family Enhancements-Electric & Gas Shared-O&M	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. 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.	2026-01-01	2026-12-31	(1.00)	-	200,628		-	-	-	-	-	-	-	124,350	-	1,290	88,781	26,249	8,051	-
213	2026	20% ROM Adjustment - Electric & Gas Shared	Software(Intangible)	Electric & Gas Shared	This is for the 20% ROM Adjustment for IT projects.							(32,773)	-	-	(22,417)	-	-	(10,356)	-	-	-	-	-	-	-
214	**SUBTOTAL**	**2026 Electric & Gas Shared**										**841,936**	-	**6,857**	**184,784**	**492,792**	**41,154**	**116,349**	**953,349**	**15,719**	**175,275**	**603,644**	**109,562**	**14,158**	**34,991**
215	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. 800MHz, mobile, and portable radios, Plant radio 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, 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.	2026-01-01	2026-12-31	(1.00)	1,565,086	221,783		1,032,856	-	703,764	46,787	243,285	-	39,020	137,463	-	116,759	11,252	8,097	-	1,354

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES
216	2026	Application Currency-IT/Digital Foundation-Application Platforms-Capital	New Computers / Hardw	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 and respective database, (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 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.
217	2026	ARP-Collaboration	New Computers / Hardw	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 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.
218	2026	ARP-Field Device Asset Management (FDAM)	New Computers / Hardw	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. 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. Alternatives considered include: (1) use 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 to complete job tasks. It would also increase risk to our MPSC requirement to meet our meter reading factor and consecutive estimated targets and it could cause applications to run poorly or stop functioning; (2) purchase the newest hardware. The Company selected this option to alleviate the above concerns.
219	2026	ARP-Operational Technology Support Electric	New Computers / Hardw	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 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 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.
220	2026	ARP-Printer Asset Management (PAM)	New Computers / Hardw	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. This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; 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 unneeded 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.
221	2026	ARP-Workstation Asset Management (WAM)	New Computers / Hardw	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.
222	2026	Operational Technology (OT) Datacenter Migration	New Computers / Hardw	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.
223	2026	20% ROM Adjustment - IT/Digital Foundation	New Computers / Hardw	IT/Digital Foundation	This is for the 20% ROM Adjustment for IT projects.
224	2026	Application Currency-IT/Digital Foundation-Application Platforms-O&M	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, (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 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.

Line No	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE
216	2026-01-01	2026-12-31	(1.00)	186,551	209,506	ROM
217	2026-01-01	2026-12-31	(1.00)	1,755,332	222,451	
218	2026-01-01	2026-12-31	(1.00)	7,687,991	5,000	
219	2026-01-01	2026-12-31	(1.00)	1,168,580	20,700	
220	2026-01-01	2026-12-31	(1.00)	182,148	5,000	
221	2026-01-01	2026-12-31	(1.00)	6,152,929	60,792	
222	2026-09-08	2027-11-16	(1.00)	7,749,620	1,856,450	ROM
223						
224	2026-01-01	2026-12-31	(1.00)	-	271,049	

Line No	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
216	127,918	-	-	87,495	-	-	40,423	129,853	-	-	121,358	-	-	8,495
217	1,203,631	-	1,022,838	111,699	58,147	10,947	-	137,876	-	-	16,052	112,805	9,020	-
218	5,271,655	-	5,136,183	92,158	-	6,451	36,863	3,099	-	3,099	-	-	-	-
219	1,168,580	-	989,830	137,500	-	-	41,250	20,700	5,000	5,000	10,000	-	-	700
220	124,899	-	123,387	1,029	-	72	411	3,099	-	3,099	-	-	-	-
221	4,219,063	-	4,013,510	97,326	58,397	10,901	38,930	37,679	-	35,766	1,788	-	125	-
222	4,715,710	342,850	3,435,357	205,710	342,850	38,399	350,544	560,397	-	-	185,942	337,794	36,661	-
223	(968,726)	(68,570)	(687,071)	(58,641)	(68,570)	(8,905)	(76,968)	-	-	-	-	-	-	-
224	-	-	-	-	-	-	-	167,998	-	-	157,007	-	-	10,990

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES
225	2026	Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	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, (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 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.
226	2026	Data & Analytics Platform Rationalization	Software(Intangible)	IT/Digital Foundation	This project will optimize the Data & Analytics system landscape by creating connections, migrating data into Data Lake 2.0 (DL 2.0), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems including SingleStore Data Lake (SSDL), SAP Business Warehouse (BW), SAP Business Objects (BOBJ), Native HANA, the BW Portal, and SAP Business Objects Data Services (BODS) creates value by reducing the total cost of ownership associated with maintaining and supporting legacy systems. 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.
227	2026	HR Support Pack and Business Software Inc Upgrade 2026	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. 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.
228	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 1 major upgrade revision behind by 2026. It's imperative our 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, our 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 bring ensure all other platform components comply with our company 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) delay the upgrade and continue operating 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) 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.
229	2026	Itron Enterprise Edition 2025 Upgrade	Software(Intangible)	IT/Digital Foundation	This project will upgrade Itron Enterprise Edition (IEE), which collects the reads from meters to ensure non-estimated bill accuracy. 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. 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 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. Alternatives considered included: (1) Defer the upgrade. This alternative was not selected because it would decouple Itron IEE (CE'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 use, creating more expense to support and no ability to leverage updated tool capability. (2) Replace 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 multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform the upgrade. This option is superior for both our customers and our Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.
230	2026	Product Family Enhancements-Application Platforms Services-Capital	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 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.
231	2026	Product Family Enhancements-Application Platforms Services-O&M	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 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.
232	2026	Product Family Enhancements-Infrastructure Platforms Services-Capital	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 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.

Line No	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
225	2026-01-01	2026-12-31	(1.00)	-	35,865		-	-	-	-	-	-	-	22,229	-	-	20,775	-	-	1,454
226	2025-04-28	2026-08-14	0.22	10,002,200	1,660,500	ROM	4,710,896	552,811	-	1,371,400	2,057,100	-	729,585	807,916	-	-	123,961	675,278	-	8,677
227	2026-02-26	2026-12-19	-	-	595,889		-	-	-	-	-	-	-	369,335	-	-	60,325	284,848	(2,019)	26,181
228	2026-02-01	2026-09-01	(1.00)	719,700	276,000	ROM	493,498	202,281	54,856	154,283	-	-	82,078	171,066	-	-	154,951	-	-	16,115
229	2025-08-12	2026-05-20	(1.00)	383,000	495,276		-	-	-	-	-	-	-	76,218	-	-	71,232	-	4,986	-
230	2026-01-01	2026-12-31	(1.00)	733,128	166,112		502,706	-	-	328,138	-	22,970	151,599	102,957	-	-	96,222	-	6,736	-
231	2026-01-01	2026-12-31	(1.00)	-	166,992		-	-	-	-	-	-	-	103,502	-	-	96,731	-	6,771	-
232	2026-01-01	2026-12-31	(1.00)	631,450	421,140		432,985	-	-	282,627	-	19,784	130,574	261,025	-	-	243,948	-	17,076	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
233	2026	Product Family Enhancements-Infrastructure Platforms Services-O&M	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 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)	-	232,859		-	-	-	-	-	-	-	144,327	-	-	134,885	-	9,442	-
234	2026	SAP S/4HANA Implementation	Software(Intangible)	IT/Digital Foundation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
235	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 our 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) Divide 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) Migrate 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) 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.	2026-04-01	2026-10-15	(1.00)	-	993,840		-	-	-	-	-	-	-	615,987	-	-	575,689	-	40,298	-
236	2026	20% ROM Adjustment - IT/Digital Foundation	Software(Intangible)	IT/Digital Foundation	This is for the 20% ROM Adjustment for IT projects.							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
237	**SUBTOTAL**	**2026 IT/Digital Foundation**										[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
238	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) upgrading or replacing 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) upgrading or replacing 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) upgrading or replacing 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		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
239	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. 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) upgrading or replacing 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) upgrading or replacing 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) upgrading or replacing 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)	412,647	16,736		412,647	200	368,500	28,586	1,800	-	13,561	16,736	-	4,000	11,903	-	-	833
240	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 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) to continue operating 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 of hardware failure and not having vendor support, software bug fixes, security updates, and other software fixes.	2026-01-01	2026-12-31	(1.00)	833,668	14,560		431,590	4,142	396,141	15,531	7,923	-	7,854	9,024	-	3,719	4,958	-	-	347
241	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 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) to continue operating 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 of hardware failure and not having 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

Synopses Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Electric & Common Capital Expenditures and O&M Expenses
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Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE
242	2026	Critical Substation Upgrade	Network	Security	This project will implement enhanced security measures at the Company Today, Consumers Energy currently deems 16 substations as business critical to our 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 our critical substation increasing the risk for large scale outages and customer impact. Our 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, we are vulnerable to an adversary causing destruction without knowledge of when or how the event took place. Consumers Energy would take a phased implementation approach to further 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 our electric substations in real-time. This enhanced security posture will align with other utilities that own and operate substations and mitigate disruption to the electric 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; (8) security equipment maintenance. These activities will be performed at the following company locations: Acme (Acme), Algoma (Sparta), Alma (Alma), Amber (Ludington), Barry (Hastings), Beals Road (Wyoming), Beecher (Adrian), Beveridge (Flint), Blackstone (Jackson), Boardman (Traverse City), Brickyard (Holton), Broadmoor (Grand Rapids), Campbell (West Olive), Cannon (Rockford), Cement City (Cement City), Churchill (Leslie), Clearwater (Kalkaska), Cleveland (Spring Lake), Cole Creek (Flushing), Crescent (Hillsdale), Croton Dam (Newaygo), David (Pewamo), Deja (Edmore), Dort (Mt. Morris), Dowling (Hudson), Edenville Dam (Hope), Edwards (Kalamazoo), Ellsworth (Grand Rapids), Elm Street (Battle Creek), Eureka (Greenville), Farr Road (Onekama), Gleaner (Freeland), Gratiot Farms (Middleton), Grodi Road (Erie), Grout (Gladwin), Hazelwood (Plainwell), Hemphill (Flint), Hile Road (Muskegon), Hodenpyl Dam (Wexford), Holland Road (Saginaw), HSC Hemlock Semiconductor (Hemlock), Hughes Road (Marshall), Island Road (Charlotte), Jackson Plymouth (Jackson), Lafayette (Battle Creek), Layton (Chesaning), Lindbergh (Kalamazoo), Looking Glass (Lansing), Manlius (New Richmond), McNally (Charlevoix), Miles Road (East Jordan), Monitor (Bay City), Moore Road (Hillsdale), Morrow (Comstock), Muskegon Heights (Muskegon), Oceana (Hart), Ogemaw (West Branch), Page Avenue (Jackson), Pasadena (Flint), Pingree (Allendale), Raisin (Tecumseh), Rice Creek (Albion), Riverview (Kalamazoo), Silicon Hemlock Semiconductor (Hemlock), Simpson (Mendon), Sonoma (Battle Creek), Spartan (East Lansing), Thompson Road (Clarksville), Trowbridge (Allegan), Twining (Twining), Vernon (Clare), VeVay (Mason), Vrooman (Jackson), Washtenaw (Chelsea), Wealthy (Grand Rapids), and Willard (Birch Run). Alternatives considered include: (1) maintain the current security perimeter fencing and conduct 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) implement enhanced security measures at the most critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time.	2026-02-15	2028-11-01	(1.00)	12,122,500	1,330,000	ROM
243	2026	20% ROM Adjustment - Security	Network	Security	This is for the 20% ROM Adjustment for Security projects.						
244	2026	ARP-Physical Security	New Computers / Hardw	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 concerns, incident 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.	2026-01-01	2026-12-31	(1.00)	2,112,820	12,626	
245	2026	Security/OT Field Modernization	New Computers / Hardw	Security	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 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 chose to deploy a dedicated OT laptop and communications circuits.	2025-03-07	2026-03-01	(1.00)	1,161,568	305,600	ROM
246	2026	20% ROM Adjustment - Security	New Computers / Hardw	Security	This is for the 20% ROM Adjustment for Security projects.						
247	2026	Application Currency-Security-Capital	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, (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.	2026-01-01	2026-12-31	(1.00)	107,000	10,700	ROM
248	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, (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.	2026-01-01	2026-12-31	(1.00)	-	337,486	
249	2026	Business Continuity - Program Management Tool	Software(Intangible)	Security	The Business Continuity Program Management Tool is critical for successful and effective Business Continuity, Disaster Recovery, and Emergency Management Programs. The software tool will provide automation, enhance the Company's incident management processes, establish critical linkages between departments and essential functions they support, and will perform necessary analysis before, during, and after a disruption that allows for the efficient response to minimize downtime. The current business continuity and disaster recovery program management tool does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. The current tool limits automation opportunities and has gaps in how it handles template enhancements, which results in the need for manual workarounds in order to prevent losing critical data. The lack of capability affects reporting, upstream / downstream impact mapping, Incident Command System (ICS) documentation automation, and user administration. This project will create value for the Company by: (1) maintaining the documentation that supports the recovery efforts of critical processes and associated essential functions that, if disrupted, would present significant impact to the Company and customers; (2) limiting business and community impact while providing a critical energy service; (3) prioritization of the recovery of critical processes and resource allocation during a business continuity incident(s); (4) providing a consistent, organized and expedient response process (Incident Command System) that is flexible to meet the needs of any incident, regardless of severity or scope; (5) providing a mechanism for identifying restorations gaps between critical business processes and IT recovery capabilities; (6) reducing or eliminating human error and waste; and (7) improved and more efficient user experience. The project scope includes: (1) framework for the development and maintenance of Business Continuity, System (Application) Recovery Plans, Incident Command System, and Disaster Recovery Plans that are effective and easily accessible during an event; (2) automation for reporting to track status and to measure effectiveness and maturity of the program (Business Continuity, Emergency Management, Disaster Recovery Programs); (3) component for facilitating effective training exercises and response efforts through incident management tools that utilize concepts from the Federal Emergency Management Agency (FEMA) National Incident Management System (NIMS); (4) program management tools to monitor required program deliverables; (5) template for developing and maintaining site hazard assessments; (6) dependency mapping of critical business processes and IT applications; and (7) integrated business impact analysis process. Alternatives considered include: (1) continue to use Riskonnect (current Disaster Recovery tool). This alternative was not selected because it currently does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. (2) Revert back to manual process. This alternative was not selected because the manual process is time consuming; and leads to human struggle and duplicative work. A previous KPMG Audit of the Business Continuity Program indicated the need for interdependency mapping and a software tool is the best way to accomplish this. (3) Implement a best-in-class Cloud Software as a Service (SaaS) solution to address the current incident management gaps and provide a consistent, organized, and expedient response process that supports the FEMA Incident Command System (ICS). This alternative was selected because there are better SaaS solutions that fit the needs outlined above.	2026-07-02	2027-02-02	(1.00)	-	144,863	

Line No	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
242	2,955,500	-	312,500	500,000	1,562,500	-	580,500	350,000	-	-	250,000	-	100,000	-
243	(306,012)	-	(32,356)	(51,770)	(161,781)	-	(60,105)	-	-	-	-	-	-	-
244	1,448,761	-	890,381	106,969	401,135	50,276	-	7,826	-	-	4,834	2,479	512	-
245	223,846	-	84,478	85,918	-	6,014	47,436	68,179	12,396	-	-	-	-	55,782
246	(44,769)	-	(16,896)	(17,184)	-	(1,203)	(9,487)	-	-	-	-	-	-	-
247	73,370	-	-	68,570	-	-	4,800	6,632	-	-	6,198	-	434	-
248	-	-	-	-	-	-	-	209,175	-	-	195,491	-	-	13,684
249	-	-	-	-	-	-	-	61,950	-	-	42,508	15,389	4,053	-

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Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE
250	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 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 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	
251	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 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 enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	(1.00)	-	489,528	
252	2026	Forward Web Proxy Services	Software(Intangible)	Security	This project will replace the current web proxy service platform with a new platform. A web proxy service is a type of proxy server that sits between a client and the internet. It acts as an intermediary that evaluates, modifies, and forwards the client The Company currently leverages an existing vendor platform for web proxy services that has been in existence since 2021. Since the implementation of the platform, it has caused ongoing operational issues related to web filtering and connectivity. When there is a degradation of service, Company employees and contractors are unable to access internet or cloud-based resources. As the Company continues its cloud and SAAS journey, it is imperative to provide consistent access and communication, while still protecting the Company from cyber threats. This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilizing 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; and (4) providing Zero Trust by continuously verifying every connection request. The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; and (3) potentially changing SAAS cloud vendors 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. This alternative was not chosen due to the consistent 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, and SharePoint Online; (2) route all internet traffic through the Company's corporate data center. This alternative was not chosen because the capabilities of firewalls are not as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) replace current system with modern vendor platform for web proxy services. The option that was chosen is to replace the current solution with a new system. This option was chosen because it offers additional features such as browser isolation (the ability to contain web pages so that the web page cannot 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 capabilities.	2025-11-03	2026-11-15	(1.00)	4,481,532	492,770	ROM
253	2026	Physical Access Management and Alarm Response	Software(Intangible)	Security	The project will replace the Company The Company This project creates value for the Company by: (1) developing an alarm and event monitoring system, which will enable seamless orchestration of system alarms and cameras; (2) adding automation that will streamline remediation processes and orchestrate camera operations for efficiency; (3) refining access revocation and badge access management to ensure only authorized personnel have entry privileges; and (4) introducing new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company The project scope includes modernizing the Company Alternatives considered were: (1) Keeping the current physical access control system and processes as-is. This alternative was not selected as the current platform is outdated, increasingly expensive to support, and does not include modern capabilities, such as digital IDs. It also does not reduce waste, cost, and it does not improve speed to delivery; (2) Developing a custom, in-house physical access control solution that includes modern capabilities, such as digital IDs. This option was not selected as the Company lacks the expertise to build such a solution. Custom-developed solutions have higher long-term, and generally result in significant waste, as well as lower speed to delivery; and (3) Implementing a new physical access control system that includes modern capabilities, such as digital IDs, that reduces waste and cost and improves speed to delivery. There are vendors in the market that specialize in physical access control systems that offer proven capabilities the Company is looking to implement. This option was selected as it will allow the Company to meet its objectives of lower waste, lower cost, improved speed to delivery, by implementing digital IDs and enabling tighter integration between the physical access control system and the Company	2026-02-28	2027-02-26	(1.00)	6,335,145	643,603	ROM
254	2026	Saviynt Enterprise Identity Governance and Access (EIGA) Implementation	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.	2023-11-27	2025-05-30	(1.00)	5,641,435	750,051	
255	2026	20% ROM Adjustment - Security	Software(Intangible)	Security	This is for the 20% ROM Adjustment for Security projects.						
256	**SUBTOTAL**	**2026 Security**									
257	**TOTAL**	**2026**									
258	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, (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 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)	-	255,306	
259	2027	Asset Accounting Tax Upgrade	Software(Intangible)	Corporate	The project will upgrade our current 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 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) 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 solution with market leaders; (2) upgrading the vendor software from the current version to the newer SaaS version or replacing it. Alternatives considered include: (1) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (2) Do nothing and remain on unsupported, on-prem tax solution. This option introduces technical and financial risk which would be costly; (3) Upgrade to the newest SaaS version of current on-prem 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.	2027-03-31	2027-10-15	(1.00)	-	371,934	

Line No	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
250	559,651	268,022	18,053	97,511	94,040	13,409	68,617	94,628	2,867	-	63,737	22,022	6,003	-
251	-	-	-	-	-	-	-	303,412	33,364	11,063	214,966	9,486	34,533	-
252	3,072,986	2,734,414	-	34,285	109,712	-	194,576	299,784	272,925	-	5,268	19,834	-	1,757
253	2,217,317	1,033,693	774,841	77,141	154,283	-	177,360	203,268	-	-	189,970	-	-	13,298
254	649,027	-	34,285	96,821	411,420	-	106,502	37,404	-	-	34,957	-	-	2,447
255	(1,072,734)	(753,621)	(154,968)	(35,999)	(52,799)	(4,680)	(70,667)	-	-	-	-	-	-	-
256	**11,577,492**	**3,287,049**	**3,559,513**	**1,052,555**	**2,531,671**	**63,816**	**1,082,888**	**1,680,732**	**321,551**	**22,081**	**1,033,590**	**69,209**	**145,535**	**88,765**
257	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
258	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
259	-	-	-	-	-	-	-	197,594	-	-	61,556	123,112	-	12,927

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
260	2027	Asset Accounting Upgrade 2027-2028	Software(Intangible)	Corporate	The project will upgrade our 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 on an undisclosed timeline. 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; (2) upgrading the vendor software from the current version to a 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 PowerPlan, 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) 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) Upgrade 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.	2027-03-31	2027-10-15	(1.00)	-	624,318		-	-	-	-	-	-	-	345,790	-	-	92,334	230,834	22,622	-
261	2027	Enterprise Risk Management	Software(Intangible)	Corporate	The project will implement software to simplify processes pertaining to Enterprise Risk Management, improve efficiency, provide risk identification and repository tools, and provide real-time risk information. The Enterprise Risk Team (ERT) works with Risk Owners (RO) on an annual basis to identify new risks, update existing risks, quantify impacts and likelihoods of these risks, document mitigation plans, identify trends, and formulate risk tolerance metrics. This work is accomplished through an iterative back-and-forth process between ERT and ROs to gain alignment on content. This effort culminates in multiple Risk Map PowerPoint, Microsoft Word and email documents organized by area of risk. These risk maps are then presented to senior management and to the Board of Directors (BoD) on an annual basis. The intensive, time-consuming manual Enterprise Risk Management (ERM) process creates risks of human error that can over or under quantify risks, introduce data anomalies, and create version tracking issues. The existing process results in substantial inefficient use of time by risk analysts and risk owners throughout the Company, limits the breadth of analysis that can be provided, and limits the overall ability of the Company to timely identify, analyze, and communicate risks to our senior leaders, thereby causing potential delays in responding to emerging risks. Because of the lengthy manual process, it is only performed once a year, but must be performed more frequently to proactively manage enterprise risk. Utility industry peers leverage software to more effectively manage enterprise risk management programs. This project creates value for the Company by: (1) providing real-time risk information to interested parties including the risk team, risk owners, senior management, and the Board of Directors (BoD) supporting proactive risk management; (2) creating a centralized repository for risk identification, management, and mitigation plans; (3) eliminating waste by simplifying processes; and (4) improving efficiency of the risk owners and analysts. The scope of the project includes: (1) create risk analysis templates and tools for automated reporting; (2) configure automated workflow to perform risk updates; (3) configure dynamic templates that prompt the risk owners based on prior selections; (4) organize risk assessments through an online and searchable data capture (repository); (5) create new reports and executive dashboards; (6) data conversion; and (7) set record retention rules. Alternatives considered include: (1) Continue use of the current manual processes. This alternative was not chosen because it results in waste, lack of quality results, and limits the frequency of reviewing of risks. (2) Build a custom internal enterprise risk solution. This alternative was not selected as it will not result in an enterprise risk program that leverages best practices that exist in software provided by the leaders in risk management software. (3) Implement a software solution from a leading enterprise risk solution vendor. While this would introduce new license and ongoing support costs, it is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation and insights via the reporting of risk information through management dashboards. In addition, it aligns the Company with utility industry peer practices for more effective enterprise risk management.	2026-04-01	2028-06-01	(1.00)	-	285,392		-	-	-	-	-	-	-	11,496	-	-	3,539	7,694	262	-
262	2027	Product Family Enhancements-Corporate-Capital	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 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)	2,121,463	311,453		1,454,687	-	-	949,535	-	66,467	438,685	193,040	-	-	180,411	-	12,629	-
263	2027	Product Family Enhancements-Corporate-O&M	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 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)	-	188,010		-	-	-	-	-	-	-	116,530	-	-	108,906	-	7,623	-
264	2027	Self Service Vendor Portal	Software(Intangible)	Corporate	The work will create an external portal for vendors to exercise self-service features to streamline and automate purchase order and invoice management and improve visibility to invoice and payment status. For Accounts Payable, vendors must repeatedly interact with the Company through multiple channels to ask questions, submit invoices, or check invoice or payment status, including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates, to make payments, or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for vendor invoice and payment management and lacks the ability for vendors to utilize touchless invoice creation from POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 6 contracted resources, and creates the potential for late payments or missing early payment discounts. For Supply Chain, vendors must repeatedly interact with the Company through multiple channels to ask questions, update POs (quantities, costs, shipping dates) including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for updates to the POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 4 employee resources. This also creates the potential for late payments, missing early payment discounts, delays in receiving due to lack of shipping notifications from vendors, delays to scheduled work due to lack of acknowledgement and lead time adherence, and the inability to enforce contractual obligations. This project creates value for the Company by: (1) creating self-service functionality/increasing touchless invoice creation/processing that allows the vendor to select items from a purchase order to create an invoice on demand; (2) providing vendors with real-time invoice and payment status, increasing employee productivity by eliminating waste (3) allow self-service updates of vendor master data (banking info, remittance info, etc.) (4) fewer late payments by vendors thus reducing Company follow up and tracking; (5) creating better visibility for vendors to take advantage of early payment discounts thus reducing related vendor inquiries; (6) reducing vendor questions related to invoice and purchase orders through self-service functions and portal information; (7) reducing the cost per invoice; (8) creating self-service functionality/increasing touchless PO creation/processing that allows the vendor to select items from a purchase order to update quantities, costs, and shipping dates; (9) providing vendors with real-time PO information, increasing employee productivity by eliminating waste; and (10) fewer late deliveries by vendors thus reducing Company follow up and tracking. The project scope includes: (1) submit an RFP for a vendor portal solution and implementation; (2) configure ability for vendors to more efficiently and more accurately self-submit invoices and POs electronically; (3) configure ability for vendors to self-convert items on a purchase order to an invoice; (4) configure ability for vendors to view invoice and payment status; (5) configure ability for vendors to make changes to SAP master data, including PO line item details; (6) configure ability to offer/process dynamic discounting (7) create new reports and dashboards; (8) enabling method to validate vendors should have access to the portal and removing access when appropriate; (9) configure ability for vendors to make self-serve changes to shipping status and delivery dates; and (10) integration to vendor invoice management system and SAP. Alternatives considered include: (1) Continue use of the current manual processes which results in waste and inefficiencies for employees and vendors. This could also result in late payments and lost discounts for vendors; (2) Build a custom solution. This option was not selected as the Company has a vendor portal, that is only leveraged for vendors to ask questions. As well, it doesn't leverage best practices; (3) Building a combination of custom and standard integration to existing solutions.	2026-03-01	2026-08-01	1.13	134,816	489,600		-	-	-	-	-	-	-	74,625	-	-	19,834	49,584	5,206	-
265	**SUBTOTAL**	**2027 Corporate**										**1,454,687**	**-**	**-**	**949,535**	**-**	**66,467**	**438,685**	**1,097,314**	**-**	**-**	**614,468**	**411,225**	**48,342**	**23,279**
266	2027	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, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the 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.	2027-01-01	2027-12-31	(1.00)	-	6,907		-	-	-	-	-	-	-	4,281	-	-	4,001	-	280	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
267	2027	Energy Assistance Enhancements and Maintenance Annual Updates	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 (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. 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. 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	-	-	311,528		-	-	-	-	-	-	-	193,086	-	-	165,087	15,368	-	12,632
268	2027	Multi-Account Online Account Management	Software(Intangible)	Customer	The project will enable additional features supporting both Commercial and Industrial and residential customers' ability to manage their accounts online. This project was formerly known as the Commercial and Industrial Online Account Management project. This enables customers to combine multiple accounts under a single login and assign authorizations to various location managers and would also establish a payment process for collective billing and self-service account management scenarios. Customers who use Bill Trust today can make one payment that covers multiple accounts, but the functionality is very limited and they can't manage the payment very well. The Company supports business customers of varying sizes which may alter how the accounts are established in the back-end system. Customers such as large universities may require multiple entries in the system to support all of their locations, requiring multiple logins to the self-service portal and several bills to be prepared. The initial C&I tool was scoped to reach business customers with multiple accounts. The broader scoped multi-account project will also reach residential customers who have More than one property, More than one meter/account (Outbuildings etc.), Multiple accounts due to moving and/or new building, and 3K accounts (non-energy billing accounts). Development of this tool directly addresses customer feedback that this specific issue is burdening their ability to manage and pay their utility bills, which is the most important transaction a customer has with the Company. When this is not functional, not only does the Company lose the efficiency, accuracy, and security of online account management and billing, but also the opportunity to opt-in, learn more or otherwise engage with Consumer's EWR and other retail offerings central to the Company and Michigan's clean energy strategies. The Company and both C&I and residential customers will see value through: (1) improved customer self-service portal for managing multiple accounts, (2) reduced touchpoints for billing inquiries, (3) ability for customers to select their bill due date, and (4) customers enabled to make a single payment on a collective bill. The scope of this project includes: (1) modifying the self-service customer portal to support managing multiple accounts under a single login replacement of an existing third-party solution that does not meet customer expectations, (2) modifying SAP to align customer accounts in an organized hierarchy, (3) updating single sign-on process to enable the customer's authorized resources (such as bookkeepers, accountants, CPAs, or attorneys) to manage the account, and (4) establishing a payment process for collective billing. Alternatives considered include: (1) Providing training to administrators of large customer accounts to better utilize the current third-party solution, which is not user-friendly and prone to errors resulting in rework to correct. This option was not selected as it does not improve customer satisfaction. (2) Utilizing Company resources to aid in administering the customer's accounts and collective billing. The Company did not select this option as it prevents the customer from self-serving their account(s) while increasing the cost of Business Contact Center resources. (3) Replacing the existing third-party solution with a cloud solution. This option was not selected because all of the other data and systems are currently on-premise and it is not cost effective to move to the cloud. (4) Replacing the existing third-party solution with an in-house solution. This option was selected as it the most cost-effective compared to the alternatives and provides the most flexibility to meet customer needs for bill payment, reviewing their energy usage, and authorizing others to manage select accounts.	2027-07-31	2028-03-31	(0.83)	5,060,485	1,143,693	ROM	2,679,023	-	-	358,100	2,009,924	88,963	222,036	555,218	-	-	80,922	454,193	20,103	-
269	2027	Product Family Enhancements-Customer-Capital	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 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)	2,734,548	124,020		1,875,079	-	6,162	202,177	1,544,945	40,926	80,871	76,869	-	-	41,799	30,892	4,177	-
270	2027	Product Family Enhancements-Customer-O&M	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 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)	-	279,082		-	-	-	-	-	-	-	172,976	-	-	103,103	58,557	11,316	-
271	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 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.	2027-01-01	2027-12-31	-	-	297,944		-	-	-	-	-	-	-	184,667	-	-	172,586	-	-	12,081
272	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 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) Migrate to a cloud solution. This alternative was not chosen due to the cost/benefit analysis of re-architecting our current Sitecore implementation to facilitate cloud migration is not 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.	2027-03-22	2027-10-01	(1.00)	-	98,297		-	-	-	-	-	-	-	60,925	-	-	56,939	-	-	3,986
273	2027	20% ROM Adjustment - Customer	Software(Intangible)	Customer	This is for the 20% ROM Adjustment for IT projects.							(535,805)	-	-	(71,620)	(401,985)	(17,793)	(44,407)	-	-	-	-	-	-	-
274	**SUBTOTAL**	**2027 Customer**										**4,018,298**	**-**	**6,162**	**488,657**	**3,152,884**	**112,097**	**258,499**	**1,248,023**	**-**	**-**	**624,437**	**559,011**	**35,877**	**28,699**
275	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 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 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)	-	248,694		-	-	-	-	-	-	-	248,694	-	-	211,541	22,346	-	14,808

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	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
	(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)
276	2027	Electric Geographic Information System (GIS) Design Platform Modernization	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 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.	2026-02-24	2029-02-22	(0.48)	6,138,677	688,999	ROM	2,209,865	1,100,000	-	724,455	-	50,712	334,698	136,794	-	-	127,845	-	8,949	-
277	2027	Electric GIS Utility Network Transformation	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.	2027-08-01	2029-10-15	(1.00)	19,378,672	5,007,911	ROM	3,972,675	1,800,000	-	235,106	1,702,591	-	234,978	1,559,856	360,000	-	305,713	758,458	74,492	61,193
278	2027	HVD SCADA Upgrade	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.	2025-03-17	2026-05-05	(1.00)	2,820,400	567,205		-	-	-	-	-	-	-	70,000	70,000	-	-	-	-	-
279	2027	Integrated Energy Management Platform Optimization	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 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 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.	2027-06-03	2028-03-09	(1.00)	4,118,296	1,570,992	ROM	4,029,896	3,357,911	-	376,740	45,000	32,560	217,685	1,523,392	-	-	202,860	1,303,000	-	17,532
280	2027	Product Family Enhancements-Electric-Capital	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 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)	1,597,161	242,126		1,597,161	-	837	883,577	214,339	117,077	381,331	242,126	-	-	96,042	130,244	15,840	-
281	2027	Product Family Enhancements-Electric-O&M	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 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)	-	240,811		-	-	-	-	-	-	-	240,811	-	-	191,760	33,297	15,754	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
282	2027	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.	2026-04-01	2027-04-30	(1.00)	1,476,795	170,130	ROM	476,421	-	-	324,096	-	-	152,325	56,023	-	-	56,023	-	-	-
283	2027	20% ROM Adjustment - Electric	Software(Intangible)	Electric	This is for the 20% ROM Adjustment for IT projects.							(2,137,771)	(1,251,582)	-	(332,079)	(349,518)	(21,192)	(183,400)	-	-	-	-	-	-	-
284	**SUBTOTAL**	**2027 Electric**										**10,148,247**	**5,006,329**	**837**	**2,211,895**	**1,612,412**	**179,157**	**1,137,617**	**4,077,696**	**430,000**	**-**	**1,191,783**	**2,247,345**	**115,035**	**93,533**
285	2027	Application Currency-Electric & Gas Shared-Capital	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, (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 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.	2027-01-01	2027-12-31	(1.00)	90,000	433,000	ROM	61,713	-	61,713	-	-	-	-	268,376	-	3,099	247,922	-	-	17,355
286	2027	Application Currency-Electric & Gas Shared-O&M	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 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.	2027-01-01	2027-12-31	(1.00)	-	514,222		-	-	-	-	-	-	-	318,718	-	-	266,844	34,163	-	17,710
287	2027	Application Currency-Operational Technology-O&M	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, (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 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)	-	295,761		-	-	-	-	-	-	-	183,314	-	-	171,322	-	-	11,993
288	2027	Itron Enterprise Edition 2027 Upgrade	Software(Intangible)	Electric & Gas Shared	This project will upgrade Itron Enterprise Edition (IEE), which collects the reads from meters to ensure non-estimated bill accuracy. 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. 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 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 considered included: (1) Defer the upgrade. This alternative was not selected because it would decouple Itron IEE (CE'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 use, creating more expense to support and no ability to leverage updated tool capability. (2) Replace 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 multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform the upgrade. This option is superior for both our customers' and our Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.	2027-02-16	2027-10-20	(1.00)	365,500	497,500	ROM	250,623	-	171,425	-	-	-	79,198	308,353	-	-	288,209	-	-	20,144
289	2027	Product Family Enhancements-Electric & Gas Shared-Capital	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 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.	2027-01-01	2027-12-31	(1.00)	1,036,665	155,294		710,841	-	6,857	95,116	492,792	41,154	74,922	96,252	-	2,899	10,396	76,850	6,107	-
290	2027	Product Family Enhancements-Electric & Gas Shared-O&M	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 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.	2027-01-01	2027-12-31	(1.00)	-	200,628		-	-	-	-	-	-	-	124,350	-	1,290	88,761	26,249	8,051	-
291	2027	20% ROM Adjustment - Electric & Gas Shared	Software(Intangible)	Electric & Gas Shared	This is for the 20% ROM Adjustment for IT projects.							(62,467)	-	(46,628)	-	-	-	(15,840)	-	-	-	-	-	-	-
292	**SUBTOTAL**	**2027 Electric & Gas Shared**										**960,710**	**-**	**193,367**	**95,116**	**492,792**	**41,154**	**138,281**	**1,299,362**	**-**	**7,287**	**1,073,454**	**137,263**	**14,158**	**67,200**

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 2024, 2025, 2026, and 2027
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)	(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
293	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. 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, 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.	2027-01-01	2027-12-31	(1.00)	1,976,855	201,862		1,023,418	-	696,940	42,998	243,280	-	37,225	125,127	-	106,575	9,241	8,097	-	1,214
294	2027	Application Currency-IT/Digital Foundation-Application Platforms-Capital	New Computers / Hardw	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 and respective databases; (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	2027-01-01	2027-12-31	(1.00)	53,071	51,788	ROM	36,391	-	-	24,891	-	-	11,500	32,098	-	-	29,999	-	-	2,100
295	2027	ARP-Collaboration	New Computers / Hardw	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 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)	1,534,983	236,036		1,052,538	-	904,907	106,851	30,308	10,471	-	146,296	-	9,297	15,480	112,557	8,962	-
296	2027	ARP-Field Device Asset Management (FDAM)	New Computers / Hardw	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. 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. Alternatives considered include: (1) use 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 to complete job tasks. It would also increase risk to our MPSC requirement to read our meter reading factor and consecutive estimated targets and it could cause applications to run poorly or stop functioning; (2) purchase the newest hardware. The Company selected this option to alleviate the above concerns.	2027-01-01	2027-12-31	(1.00)	5,845,227	5,000		4,008,072	-	3,910,097	66,650	-	4,666	26,660	3,099	-	3,099	-	-	-	-
297	2027	ARP-Operational Technology Support Common	New Computers / Hardw	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 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. 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 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)	185,567	5,140		127,929	-	121,243	5,143	-	-	1,543	3,186	1,240	620	1,240	-	-	87
298	2027	ARP-Operational Technology Support Electric	New Computers / Hardw	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 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 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)	917,189	19,025		917,189	-	855,439	47,500	-	-	14,250	19,025	6,000	5,000	7,500	-	-	525
299	2027	ARP-Printer Asset Management (PAM)	New Computers / Hardw	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. This project creates value for the Company by: (1) improving the dependability of printer devices for employees. 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 unneeded 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.	2027-01-01	2027-12-31	(1.00)	675,303	5,000		463,055	-	452,169	7,406	-	518	2,962	3,099	-	3,099	-	-	-	-
300	2027	ARP-Server and Storage	New Computers / Hardw	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. 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.	2027-01-01	2027-12-31	(1.00)	1,415,674	116,800		970,728	-	752,127	137,140	-	9,600	71,861	72,393	-	-	-	61,980	10,413	-
301	2027	ARP-Workstation Asset Management (WAM)	New Computers / Hardw	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 if 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 assets 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 systems 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.	2027-01-01	2027-12-31	(1.00)	6,926,555	70,943		4,749,539	-	4,553,579	92,785	55,669	10,392	37,114	43,971	-	41,738	2,087	-	146	-
302	2027	Operational Technology (OT) Datacenter Migration	New Computers / Hardw	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.	2026-09-08	2027-11-16	(1.00)	7,749,620	1,856,450	ROM	598,205	-	-	137,140	342,850	33,599	84,615	590,240	-	-	216,932	334,695	38,614	-
303	2027	20% ROM Adjustment - IT/Digital Foundation	New Computers / Hardw	IT/Digital Foundation	This is for the 20% ROM Adjustment for IT projects.							(126 919)	-	-	(32 406)	(68 570)	(7 028)	(18 914)	-	-	-	-	-	-	-

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 2024, 2025, 2026, and 2027
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)	(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
304	2027	Application Currency-IT-Digital Foundation-Application Platforms-O&M	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, (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	2027-01-01	2027-12-31	(1.00)	-	216,343		-	-	-	-	-	-	-	134,091	-	-	125,318	-	-	8,772
305	2027	Application Currency-IT-Digital Foundation-Infrastructure Platforms-O&M	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, (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	2027-01-01	2027-12-31	(1.00)	-	35,865		-	-	-	-	-	-	-	22,229	-	-	20,775	-	-	1,454
306	2027	AirWay Secure Transport 2027 Upgrade	Software(Intangible)	IT/Digital Foundation	Aeway SecureTransport is the official CE 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. As Aeway SecureTransport 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. 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 Aeway; (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. (2) enabling and testing in scope file transfer processes. Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because the Aeway 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 Aeway 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.	2027-01-15	2027-07-15	(1.00)	-	371,934		-	-	-	-	-	-	-	230,527	-	-	215,445	-	-	15,081
307	2027	Digital-Infrastructure Automation	Software(Intangible)	IT/Digital Foundation	This project will automate the deployment, maintenance, and tear down or decommissioning of cloud and data center services, leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services while reducing operational costs. As the company uses cloud services to provide infrastructure for applications, the difficulty of manually deploying, maintaining, and decommissioning infrastructure, improving efficiency of the use of infrastructure, bolstering resiliency, maintaining security posture, and extending new capabilities increases significantly. The manual approach lengthens application implementation times and leads to inconsistent and/or incorrect deployment of infrastructure. This project will create value by ensuring the Company's application infrastructure requirements are met through automation. Specifically, the project will create automation to deploy, maintain, and deprovision infrastructure in a modular fashion to be used by product teams to deploy, maintain, upgrade, and deprovision Company applications. Thus, the project will: (1) improve the efficiency of the use of infrastructure by allowing for infrastructure to be provisioned when needed, and deprovisioned when not needed; (2) bolster the resiliency of infrastructure by creating reusable resilient patterns and scalability for applications to use; (3) deploying and removing infrastructure securely; and (4) enhancing or extending automation for new cloud and data center services to support Company applications. The project scope includes: (1) procuring automation software; (2) building automation for cloud and data center services; (3) building resiliency and scalability into the services; (4) building security posture into the services; and (5) enhancing existing or extending automation for new services. Alternatives considered include: (1) manually deploying, maintaining, and decommissioning infrastructure to support Company applications. This alternative was not chosen because it has proven to be slow, costly, and error-prone; (2) manually improving the efficiency in the use of infrastructure. This alternative was not chosen because the Company does not have the necessary people to manually do this work at the scale necessary to support the Company's portfolio of applications; (3) manually bolstering resiliency. This alternative was not chosen because it has proven to be error-prone; (4) manually maintaining security posture. This alternative was not chosen because the Company does not have the necessary people to manually do this work at the scale necessary to support the Company's portfolio of applications; (5) manually extending new cloud services. This alternative was not chosen because the services were available faster than the Company can manually deploy them while meeting necessary standards and security postures; (6) and utilizing pre-built tooling without extension or development. This alternative was not chosen because pre-built tooling does not meet the necessary Company standards and security postures. (7) procure automation software and extend the software to meet Company standards. This alternative was selected because the combination provides the most cost-effective method for automation of existing and new services at speed and scale while allowing the services to be deployed in a secure manner that meets Company standards.	2027-02-28	2028-09-30	(1.00)	3,708,606	1,527,930	ROM	1,432,662	274,280	-	724,757	27,428	406,197	-	479,707	-	-	436,739	-	30,572	12,396
308	2027	HR Support Pack and Business Software Inc Upgrade 2027	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 to the Company. 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.	2027-02-27	2027-12-22	-	-	595,889		-	-	-	-	-	-	-	369,335	-	-	60,325	284,848	(2,019)	26,181
309	2027	Product Family Enhancements-Application Platforms Services-Capital	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. 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)	733,128	166,112		502,706	-	-	328,138	-	22,970	151,599	102,957	-	-	96,222	-	6,736	-
310	2027	Product Family Enhancements-Application Platforms Services-O&M	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. 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)	-	166,992		-	-	-	-	-	-	-	103,502	-	-	96,731	-	6,771	-

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE
311	2027	Product Family Enhancements-Infrastructure Platforms Services-Capital	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 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)	631,450	421,140	
312	2027	Product Family Enhancements-Infrastructure Platforms Services-O&M	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 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)	-	232,859	
313	2027	SAP S/4HANA Implementation	Software(Intangible)	IT/Digital Foundation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
314	2027	20% ROM Adjustment - IT/Digital Foundation	Software(Intangible)	IT/Digital Foundation	This is for the 20% ROM Adjustment for IT projects.						
315	**SUBTOTAL**	**2027 IT/Digital Foundation**									
316	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 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) upgrading or replacing 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) upgrading or replacing 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) upgrading or replacing 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)	1,451,918	16,664	
317	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) upgrading or replacing 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) upgrading or replacing 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) upgrading or replacing 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)	465,580	19,377	
318	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 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) to continue operating 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 of hardware failure and not having vendor support, software bug fixes, security updates, and other software fixes.	2027-01-01	2027-12-31	(1.00)	1,515,192	24,980	
319	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 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) to continue operating 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 of hardware failure and not having vendor support, software bug fixes, security updates, and other software fixes.	2027-01-01	2027-12-31	(1.00)	22,156	635	

Line No	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
311	432,985	-	-	282,627	-	19,784	130,574	261,025	-	-	243,948	-	17,076	-
312	-	-	-	-	-	-	-	144,327	-	-	134,885	-	9,442	-
313	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
314	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-
315	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
316	[redacted]	-	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]	-	[redacted]	[redacted]	-	-	[redacted]
317	465,580	200	416,000	32,282	1,800	-	15,298	19,377	-	5,000	13,437	-	-	941
318	784,415	8,801	731,796	19,155	14,636	-	10,028	15,483	-	6,198	8,677	-	-	607
319	22,156	100	19,435	1,500	389	-	732	635	-	100	500	-	-	35

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 2024, 2025, 2026, and 2027
Information Technology Department

Line No	(a) SPEND YEAR	(b) PROJECT NAME	(c) FERC CATEGORY	(d) BUSINESS CATEGORY/ PRODUCT LINE	(e) PROJECT SYNOPSES	(f) PROJECT START DATE	(g) PROJECT END DATE	(h) COST/ BENEFIT RATIO	(i) TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	(j) TOTAL COMPANY EXPECTED PROJECT O&M COSTS	(k) ESTIMATE TYPE	(l) ELECTRIC PORTION CAPITAL SPEND FOR APPLICABLE YEAR	(m) SOFTWARE COSTS-ELECTRIC	(n) MATERIAL COSTS-ELECTRIC	(o) LABOR COSTS-ELECTRIC	(p) CONTRACTOR COSTS-ELECTRIC	(q) NON-LABOR OVERHEAD-ELECTRIC	(r) NON-LABOR OTHER-ELECTRIC	(s) ELECTRIC PORTION O&M SPEND FOR APPLICABLE YEAR	(t) SOFTWARE COSTS-ELECTRIC	(u) MATERIAL COSTS-ELECTRIC	(v) LABOR COSTS-ELECTRIC	(w) CONTRACTOR COSTS-ELECTRIC	(x) NON-LABOR OVERHEAD-ELECTRIC	(y) NON-LABOR OTHER-ELECTRIC
320	2027	Critical Substation Upgrade	Network	Security	This project will implement enhanced security measures at the Company Today, Consumers Energy currently deems 16 substations as business critical to our 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 our critical substation increasing the risk for large scale outages and customer impact. Our 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, we are vulnerable to an adversary causing destruction without knowledge of when or how the event took place. Consumers Energy would take a phased implementation approach to further 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 our electric substations in real-time. This enhanced security posture will align with other utilities that own and operate substations and mitigate disruption to the electric 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; (8) security equipment maintenance. These activities will be performed at the following company locations: Acme (Acme), Algoma (Sparta), Alma (Alma), Amber (Ludington), Barry (Hastings), Beals Road (Wyoming), Beecher (Adrian), Beveridge (Flint), Blackstone (Jackson), Boardman (Traverse City), Brickyard (Holton), Broadmoor (Grand Rapids), Campbell (West Olive), Cannon (Rockford), Cement City (Cement City), Churchill (Leslie), Clearwater (Kalkaska), Cleveland (Spring Lake), Cole Creek (Flushing), Crescent (Hillsdale), Croton Dam (Newaygo), David (Pewamo), Deja (Edmore), Dort (Mt. Morris), Dowling (Hudson), Edenville Dam (Hope), Edwards (Kalamazoo), Ellsworth (Grand Rapids), Elm Street (Battle Creek), Eureka (Greenville), Farr Road (Onekama), Gleaner (Freeland), Gratiot Farms (Middleton), Grodi Road (Erie), Grout (Gladwin), Hazelwood (Plainwell), Hemphill (Flint), Hile Road (Muskegon), Hodenpyl Dam (Wexford), Holland Road (Saginaw), HSC Hemlock Semiconductor (Hemlock), Hughes Road (Marshall), Island Road (Charlotte), Jackson Plymouth (Jackson), Lafayette (Battle Creek), Layton (Chesaning), Lindbergh (Kalamazoo), Looking Glass (Lansing), Manlius (New Richmond), McNally (Charlevoix), Miles Road (East Jordan), Monitor (Bay City), Moore Road (Hillsdale), Morrow (Comstock), Muskegon Heights (Muskegon), Oceana (Hart), Ogemaw (West Branch), Page Avenue (Jackson), Pasadena (Flint), Pingree (Allendale), Raisin (Tecumseh), Rice Creek (Albion), Riverview (Kalamazoo), Silicon Hemlock Semiconductor (Hemlock), Simpson (Mendon), Sonoma (Battle Creek), Spartan (East Lansing), Thompson Road (Clarksville), Trowbridge (Allegan), Twining (Twining), Vernon (Clare), VeVay (Mason), Vrooman (Jackson), Washtenaw (Chelsea), Wealthy (Grand Rapids), and Willard (Birch Run). Alternatives considered include: (1) maintain the current security perimeter fencing and conduct 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) implement enhanced security measures at the most critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time.	2026-02-15	2028-11-01	(1.00)	12,122,500	1,330,000	ROM	4,583,500	-	312,500	1,000,000	2,562,500	-	708,500	490,000	-	-	350,000	-	140,000	-
321	2027	20% ROM Adjustment - Security	Network	Security	This is for the 20% ROM Adjustment for Security projects.							(474,576)	-	(32,356)	(103,540)	(265,321)	-	(73,358)	-	-	-	-	-	-	-
322	2027	ARP-Physical Security	New Computers / Hardw	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 concerns, incident 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.	2027-01-01	2027-12-31	(1.00)	2,114,320	12,626		1,449,789	-	891,410	106,969	401,135	50,276	-	7,826	-	-	4,834	2,479	512	-
323	2027	Application Currency-Security-Capital	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, (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.	2027-01-01	2027-12-31	(1.00)	107,000	10,700	ROM	73,370	-	-	68,570	-	-	4,800	6,632	-	-	6,198	-	434	-
324	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, (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.	2027-01-01	2027-12-31	(1.00)	-	337,486		-	-	-	-	-	-	-	209,175	-	-	195,491	-	-	13,684
325	2027	Business Continuity - Program Management Tool	Software(Intangible)	Security	The Business Continuity Program Management Tool is critical for successful and effective Business Continuity, Disaster Recovery, and Emergency Management Programs. The software tool will provide automation, enhance the Company's incident management processes, establish critical linkages between departments and essential functions they support, and will perform necessary analysis before, during, and after a disruption that allows for the efficient response to minimize downtime. The current business continuity and disaster recovery program management tool does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. The current tool limits automation opportunities and has gaps in how it handles template enhancements, which results in the need for manual workarounds in order to prevent losing critical data. The lack of capability affects reporting, upstream / downstream impact mapping, Incident Command System (ICS) documentation automation, and user administration. This project will create value for the Company by: (1) maintaining the documentation that supports the recovery efforts of critical processes and associated essential functions that, if disrupted, would present significant impact to the Company and customers; (2) limiting business and community impact while providing a critical energy service; (3) prioritization of the recovery of critical processes and resource allocation during a business continuity incident(s); (4) providing a consistent, organized and expedient response process (Incident Command System) that is flexible to meet the needs of any incident, regardless of severity or scope; (5) providing a mechanism for identifying restorations gaps between critical business processes and IT recovery capabilities; (6) reducing or eliminating human error and waste; and (7) improved and more efficient user experience. The project scope includes: (1) framework for the development and maintenance of Business Continuity, System (Application) Recovery Plans, Incident Command System, and Disaster Recovery Plans that are effective and easily accessible during an event; (2) automation for reporting to track status and to measure effectiveness and maturity of the program (Business Continuity, Emergency Management, Disaster Recovery Programs); (3) component for facilitating effective training exercises and response efforts through incident management tools that utilize concepts from the Federal Emergency Management Agency (FEMA) National Incident Management System (NIMS); (4) program management tools to monitor required program deliverables; (5) template for developing and maintaining site hazard assessments; (6) dependency mapping of critical business processes and IT applications; and (7) integrated business impact analysis process. Alternatives considered include: (1) continue to use Riskonnect (current Disaster Recovery tool). This alternative was not selected because it currently does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. (2) Revert back to manual process. This alternative was not selected because the manual process is time consuming; and leads to human struggle and duplicative work. A previous KPMG Audit of the Business Continuity Program indicated the need for interdependency mapping and a software tool is the best way to accomplish this. (3) Implement a best-in-class Cloud Software as a Service (SaaS) solution to address the current incident management gaps and provide a consistent, organized, and expedient response process that supports the FEMA Incident Command System (ICS). This alternative was selected because there are better SaaS solutions that fit the needs outlined above.	2026-07-02	2027-02-02	(1.00)	-	144,863		-	-	-	-	-	-	-	27,837	-	-	10,627	15,389	1,821	-
326	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 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 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 enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	(1.00)	816,175	152,674		559,651	268,022	18,053	97,511	94,040	13,409	68,617	94,628	2,867	-	63,737	22,022	6,003	-

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 2024, 2025, 2026, and 2027
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)	(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
327	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 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. 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 enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2027-01-01	2027-12-31	(1.00)	-	488,529		-	-	-	-	-	-	-	303,412	33,364	11,063	214,986	9,488	34,533	-
328	2027	Forward Web Proxy Services	Software(Intangible)	Security	This project will replace the current web proxy service platform with a new platform. A web proxy service is a type of proxy server that sits between a client and the internet. It acts as an intermediary that evaluates, modifies, and forwards the client. The Company currently leverages an existing vendor platform for web proxy services that has been in existence since 2021. Since the implementation of the platform, it has caused ongoing operational issues related to web filtering and connectivity. When there is a degradation of service, Company employees and contractors are unable to access internet or cloud-based resources. As the Company continues its cloud and SAAS journey, it is imperative to provide consistent access and communication, while still protecting the Company from cyber threats. This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilizing 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; and (4) providing Zero Trust by continuously verifying every connection request. The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; and (3) potentially changing SAAS cloud vendors. 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. This alternative was not chosen due to the consistent 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, and SharePoint Online; (2) route all internet traffic through the Company's corporate data center. This alternative was not chosen because the capabilities of firewalls are not as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) replace current system with modern vendor platform for web proxy services. The option that was chosen is to replace the current solution with a new system. This option was chosen because it offers additional features such as browser isolation (the ability to contain web pages so that the web page cannot 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 capabilities.	2025-11-03	2026-11-15	(1.00)	4,481,532	492,770		-	-	-	-	-	-	-	5,637	-	-	5,268	-	-	369
329	2027	Physical Access Management and Alarm Response	Software(Intangible)	Security	The project will replace the Company The Company This project creates value for the Company by: (1) developing an alarm and event monitoring system, which will enable seamless orchestration of system alarms and cameras; (2) adding automation that will streamline remediation processes and orchestrate camera operations for efficiency; (3) refining access revocation and badge access management to ensure only authorized personnel have entry privileges; and (4) introducing new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company The project scope includes modernizing the Company Alternatives considered were: (1) Keeping the current physical access control system and processes as-is. This alternative was not selected as the current platform is outdated, increasingly expensive to support, and does not include modern capabilities, such as digital IDs. It also does not reduce waste, cost, and it does not improve speed to delivery; (2) Developing a custom, in-house physical access control solution that includes modern capabilities, such as digital IDs. This option was not selected as the Company lacks the expertise to build such a solution. Custom-developed solutions have higher long-term, and generally result in significant waste, as well as lower speed to delivery; and (3) Implementing a new physical access control system that includes modern capabilities, such as digital IDs, that reduces waste and cost and improves speed to delivery. There are vendors in the market that specialize in physical access control systems that offer proven capabilities the Company is looking to implement. This option was selected as it will allow the Company to meet its objectives of lower waste, lower cost, improved speed to delivery, by implementing digital IDs and enabling tighter integration between the physical access control system and the Company	2026-02-28	2027-02-26	(1.00)	6,335,145	643,603	ROM	1,063,346	61,713	771,413	46,285	92,570	-	91,366	97,820	9,483	-	82,558	-	-	5,779
330	2027	20% ROM Adjustment - Security	Software(Intangible)	Security	This is for the 20% ROM Adjustment for Security projects.							(227,343)	(12,343)	(154,283)	(22,971)	(18,514)	(2,904)	(16,329)	-	-	-	-	-	-	-
331	**SUBTOTAL**	**2027 Security**										**9,951,946**	**326,453**	**5,671,827**	**1,269,980**	**2,695,183**	**66,760**	**626,332**	**1,288,791**	**46,713**	**25,461**	**963,950**	**49,376**	**183,363**	**21,888**
332	**TOTAL**	**2027**																							

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.

2025 Union Contract Changes

Report Pulled: 4/23/2025 **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 -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	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
4/1/2025	5/15/2025	6/28/2025	12/17/2025
	In-Service/Go-Live	**Closeout**	
	12/18/2025	5/1/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.327	$0.281	$0.008	$0.008	$0.008	-	-	-	$0.632
Total Cost of Ownership	$0.327	$0.281	$0.008	$0.008	$0.008	-	-	-	**$0.632**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.137	$0.111	-	-	-	-	-	-	**$0.248**
Outside Services	$0.169	$0.145	-	-	-	-	-	-	**$0.314**
Business Expense/Overheads	$0.021	$0.018	-	-	-	-	-	-	**$0.039**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.327	$0.273	-	-	-	-	-	-	**$0.601**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.327	$0.281	$0.008	$0.008	$0.008	-	-	-	**$0.632**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.327	$0.281	$0.008	$0.008	$0.008	-	-	-	**$0.632**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

2025 Union Contract Changes

Report Pulled: 4/23/2025 **Item ID: 13951**

EXECUTIVE SUMMARY

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.

Application Currency-Corporate-Capital

Report Pulled: 4/23/2025 **Item ID:** 13356

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Application Currency-Corporate-Capital

Description The Corporate Services 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 > 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, (5) 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.210	-	$0.138	-	-	-	-	-	$0.348
O&M	-	-	$0.013	-	-	-	-	-	$0.013
Total Cost of Ownership	$0.210	-	$0.150	-	-	-	-	-	**$0.360**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.150	-	$0.024	-	-	-	-	-	**$0.174**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.060	-	$0.006	-	-	-	-	-	**$0.066**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.120	-	-	-	-	-	**$0.120**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.210	-	$0.150	-	-	-	-	-	**$0.360**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	$0.013	-	-	-	-	-	**$0.013**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	$0.013	-	-	-	-	-	**$0.013**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.210	-	$0.138	-	-	-	-	-	**$0.348**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.210	-	$0.138	-	-	-	-	-	**$0.348**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000 #REF!

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-Corporate-O&M

Report Pulled: 4/23/2025 **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, (5) 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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.236	$0.366	$0.340	$0.310	$0.255	$0.263	$0.255	-	$2.025
Total Cost of Ownership	$0.236	$0.366	$0.340	$0.310	$0.255	$0.263	$0.255	-	**$2.025**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.170	$0.083	$0.318	$0.289	$0.239	$0.246	$0.239	-	**$1.585**
Outside Services	$0.062	$0.282	-	-	-	-	-	-	**$0.344**
Business Expense/Overheads	$0.003	-	$0.022	$0.020	$0.017	$0.017	$0.017	-	**$0.096**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.000	-	-	-	-	-	-	-	**$0.000**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.236	$0.366	$0.340	$0.310	$0.255	$0.263	$0.255	-	**$2.025**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.236	$0.366	$0.340	$0.310	$0.255	$0.263	$0.255	-	**$2.025**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.236	$0.366	$0.340	$0.310	$0.255	$0.263	$0.255	-	**$2.025**
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: 4/23/2025 **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, (5) 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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.107	$0.062	$0.010	$0.175	$0.007	$0.169	-	-	$0.530
Total Cost of Ownership	$0.107	$0.062	$0.010	$0.175	$0.007	$0.169	-	-	**$0.530**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.090	$0.007	$0.009	$0.164	$0.007	$0.158	-	-	**$0.435**
Outside Services	$0.016	$0.054	-	-	-	-	-	-	**$0.070**
Business Expense/Overheads	$0.000	-	$0.001	$0.011	$0.000	$0.011	-	-	**$0.024**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.001	-	-	-	-	-	-	-	**$0.001**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.107	$0.062	$0.010	$0.175	$0.007	$0.169	-	-	**$0.530**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.107	$0.062	$0.010	$0.175	$0.007	$0.169	-	-	**$0.530**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.107	$0.062	$0.010	$0.175	$0.007	$0.169	-	-	**$0.530**
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-Electric & Gas Shared-Capital

Report Pulled: 4/23/2025 **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, (5) 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.740	$0.052	$0.062	$0.090	-	-	-	-	$0.944
O&M	$0.138	$0.184	$0.309	$0.433	$0.188	-	-	-	$1.252
Total Cost of Ownership	$0.878	$0.236	$0.372	$0.523	$0.188	-	-	-	**$2.196**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.117	$0.222	$0.050	$0.400	$0.175	-	-	-	**$0.964**
Outside Services	$0.065	-	-	-	-	-	-	-	**$0.065**
Business Expense/Overheads	$0.058	$0.014	$0.020	$0.028	$0.013	-	-	-	**$0.132**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	$0.276	$0.095	-	-	-	-	**$0.371**
Licenses, Permits & Fees	$0.637	-	$0.025	-	-	-	-	-	**$0.663**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.878	$0.236	$0.372	$0.523	$0.188	-	-	-	**$2.196**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.138	$0.184	$0.309	$0.433	$0.188	-	-	-	**$1.252**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.138	$0.184	$0.309	$0.433	$0.188	-	-	-	**$1.252**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.740	$0.052	$0.062	$0.090	-	-	-	-	**$0.944**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.740	$0.052	$0.062	$0.090	-	-	-	-	**$0.944**
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-Electric & Gas Shared-O&M

Report Pulled: 4/23/2025 **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, (5) 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.058	$0.402	$0.512	$0.514	$0.673	$0.295	-	-	$2.454
Total Cost of Ownership	$0.058	$0.402	$0.512	$0.514	$0.673	$0.295	-	-	**$2.454**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.014	$0.372	$0.469	$0.431	$0.617	$0.228	-	-	**$2.132**
Outside Services	$0.044	$0.002	$0.010	$0.055	$0.012	$0.053	-	-	**$0.177**
Business Expense/Overheads	-	$0.027	$0.032	$0.029	$0.044	$0.014	-	-	**$0.146**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.058	$0.402	$0.512	$0.514	$0.673	$0.295	-	-	**$2.454**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.058	$0.402	$0.512	$0.514	$0.673	$0.295	-	-	**$2.454**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.058	$0.402	$0.512	$0.514	$0.673	$0.295	-	-	**$2.454**
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
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-Electric-Capital

Report Pulled: 4/23/2025 **Item ID: 13362**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Application Currency-Electric-Capital

Description The Electric/Generation/Renewables Engineering and 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 > 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, (5) 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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.050	-	$0.044	-	-	-	-	-	$0.094
O&M	-	-	-	-	-	-	-	-	-
Total Cost of Ownership	$0.050	-	$0.044	-	-	-	-	-	**$0.094**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	-	$0.030	-	-	-	-	-	**$0.030**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	-	$0.014	-	-	-	-	-	**$0.014**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.050	-	-	-	-	-	-	-	**$0.050**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.050	-	$0.044	-	-	-	-	-	**$0.094**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.050	-	$0.044	-	-	-	-	-	**$0.094**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.050	-	$0.044	-	-	-	-	-	**$0.094**
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-Electric-O&M

Report Pulled: 4/23/2025 **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, (5) 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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.008	$0.118	$0.211	$0.325	$0.264	$0.268	$0.269	-	$1.463
Total Cost of Ownership	$0.008	$0.118	$0.211	$0.325	$0.264	$0.268	$0.269	-	**$1.463**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.007	$0.118	$0.197	$0.301	$0.225	$0.251	$0.230	-	**$1.329**
Outside Services	-	-	-	$0.003	$0.024	-	$0.024	-	**$0.050**
Business Expense/Overheads	$0.001	-	$0.014	$0.021	$0.016	$0.017	$0.016	-	**$0.084**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.008	$0.118	$0.211	$0.325	$0.264	$0.268	$0.269	-	**$1.463**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.008	$0.118	$0.211	$0.325	$0.264	$0.268	$0.269	-	**$1.463**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.008	$0.118	$0.211	$0.325	$0.264	$0.268	$0.269	-	**$1.463**
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 Plat Report Pulled: 4/23/2025 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 & SER

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, (5) 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$0.048	$0.187	$0.053	$0.190	$0.056	-	-	$0.534
O&M	-	$0.020	$0.210	$0.052	$0.211	$0.054	-	-	$0.547
Total Cost of Ownership	-	$0.069	$0.396	$0.105	$0.401	$0.110	-	-	**$1.081**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.050	$0.323	$0.085	$0.327	$0.089	-	-	**$0.875**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	-	$0.018	$0.073	$0.020	$0.074	$0.021	-	-	**$0.206**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	-	$0.069	$0.396	$0.105	$0.401	$0.110	-	-	**$1.081**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	$0.020	$0.210	$0.052	$0.211	$0.054	-	-	**$0.547**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	$0.020	$0.210	$0.052	$0.211	$0.054	-	-	**$0.547**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	$0.048	$0.187	$0.053	$0.190	$0.056	-	-	**$0.534**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	$0.048	$0.187	$0.053	$0.190	$0.056	-	-	**$0.534**
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 Plat Report Pulled: 4/23/2025 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 & SER

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, (5) 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.225	$0.091	$0.271	$0.216	$0.177	$0.273	-	-	$1.253
Total Cost of Ownership	$0.225	$0.091	$0.271	$0.216	$0.177	$0.273	-	-	**$1.253**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.225	$0.077	$0.253	$0.202	$0.165	$0.255	-	-	**$1.178**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	-	$0.014	$0.018	$0.014	$0.012	$0.018	-	-	**$0.075**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.225	$0.091	$0.271	$0.216	$0.177	$0.273	-	-	**$1.253**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.225	$0.091	$0.271	$0.216	$0.177	$0.273	-	-	**$1.253**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.225	$0.091	$0.271	$0.216	$0.177	$0.273	-	-	**$1.253**
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 P Report Pulled: 4/23/2025 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 &

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, (5) 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.024	$0.020	$0.038	$0.038	$0.038	$0.038	-	-	$0.196
Total Cost of Ownership	$0.024	$0.020	$0.038	$0.038	$0.038	$0.038	-	-	**$0.196**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.024	$0.017	$0.036	$0.036	$0.036	$0.036	-	-	**$0.183**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	-	$0.003	$0.002	$0.002	$0.002	$0.002	-	-	**$0.013**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.024	$0.020	$0.038	$0.038	$0.038	$0.038	-	-	**$0.196**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.024	$0.020	$0.038	$0.038	$0.038	$0.038	-	-	**$0.196**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.024	$0.020	$0.038	$0.038	$0.038	$0.038	-	-	**$0.196**
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: 4/23/2025 **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 & SER

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, (5) 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.072	-	$0.177	-	$0.366	-	-	-	$0.614
O&M	$0.004	-	$0.055	-	$0.107	-	-	-	$0.166
Total Cost of Ownership	$0.075	-	$0.232	-	$0.473	-	-	-	**$0.780**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.019	-	$0.173	-	$0.350	-	-	-	**$0.542**
Outside Services	$0.001	-	-	-	-	-	-	-	**$0.001**
Business Expense/Overheads	$0.004	-	$0.060	-	$0.123	-	-	-	**$0.186**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.052	-	-	-	-	-	-	-	**$0.052**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.075	-	$0.232	-	$0.473	-	-	-	**$0.780**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.004	-	$0.055	-	$0.107	-	-	-	**$0.166**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.004	-	$0.055	-	$0.107	-	-	-	**$0.166**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.072	-	$0.177	-	$0.366	-	-	-	**$0.614**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.072	-	$0.177	-	$0.366	-	-	-	**$0.614**
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: 4/23/2025 **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 & SEI

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, (5) 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.093	$0.102	$0.324	$0.314	$0.387	$0.320	-	-	$1.540
Total Cost of Ownership	$0.093	$0.102	$0.324	$0.314	$0.387	$0.320	-	-	**$1.540**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.070	$0.087	$0.303	$0.293	$0.361	$0.299	-	-	**$1.413**
Outside Services	$0.021	-	-	-	-	-	-	-	**$0.021**
Business Expense/Overheads	$0.002	$0.015	$0.021	$0.021	$0.025	$0.021	-	-	**$0.105**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.000	-	-	-	-	-	-	-	**$0.000**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.093	$0.102	$0.324	$0.314	$0.387	$0.320	-	-	**$1.540**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.093	$0.102	$0.324	$0.314	$0.387	$0.320	-	-	**$1.540**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.093	$0.102	$0.324	$0.314	$0.387	$0.320	-	-	**$1.540**
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: 4/23/2025 **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 M(

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, (5) 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$0.146	$0.107	$0.107	$0.146	$0.146	-	-	$0.653
O&M	$0.001	$0.005	$0.011	$0.011	$0.011	$0.011	-	-	$0.048
Total Cost of Ownership	$0.001	$0.151	$0.118	$0.118	$0.157	$0.157	-	-	**$0.701**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.104	$0.110	$0.110	$0.110	$0.110	-	-	**$0.544**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	-	$0.047	$0.008	$0.008	$0.047	$0.047	-	-	**$0.156**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.000	-	-	-	-	-	-	-	**$0.000**
Licenses, Permits & Fees	$0.001	-	-	-	-	-	-	-	**$0.001**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.001	$0.151	$0.118	$0.118	$0.157	$0.157	-	-	**$0.701**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.001	$0.005	$0.011	$0.011	$0.011	$0.011	-	-	**$0.048**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.001	$0.005	$0.011	$0.011	$0.011	$0.011	-	-	**$0.048**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	$0.146	$0.107	$0.107	$0.146	$0.146	-	-	**$0.653**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	$0.146	$0.107	$0.107	$0.146	$0.146	-	-	**$0.653**
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-Security-O&M

Report Pulled: 4/23/2025 **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 M(

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, (5) 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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.029	$0.009	$0.155	$0.358	$0.358	$0.358	$0.358	-	$1.626
Total Cost of Ownership	$0.029	$0.009	$0.155	$0.358	$0.358	$0.358	$0.358	-	**$1.626**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.029	$0.009	$0.131	$0.335	$0.335	$0.335	$0.335	-	**$1.508**
Outside Services	-	$0.000	-	-	-	-	-	-	**$0.000**
Business Expense/Overheads	$0.000	-	$0.023	$0.023	$0.023	$0.023	$0.023	-	**$0.117**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.029	$0.009	$0.155	$0.358	$0.358	$0.358	$0.358	-	**$1.626**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.029	$0.009	$0.155	$0.358	$0.358	$0.358	$0.358	-	**$1.626**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.029	$0.009	$0.155	$0.358	$0.358	$0.358	$0.358	-	**$1.626**
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-TEOS-O&M

Report Pulled: 4/23/2025 **Item ID: 8775**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Enhancements - TEOS - O&M, Application Currency and Enhancements - TEOS -O&M, Application Currency - TEOS - O&M, Application Currency-TEOS-O&M

Description The TEOS 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-TRANS, OPS SUPPORT AND ENG

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 TEOS 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, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the TEOS 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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.078	$0.228	-	-	-	-	-	-	$0.306
Total Cost of Ownership	$0.078	$0.228	-	-	-	-	-	-	**$0.306**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.025	$0.098	-	-	-	-	-	-	**$0.123**
Outside Services	$0.051	$0.130	-	-	-	-	-	-	**$0.181**
Business Expense/Overheads	$0.002	$0.000	-	-	-	-	-	-	**$0.002**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.078	$0.228	-	-	-	-	-	-	**$0.306**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.078	$0.228	-	-	-	-	-	-	**$0.306**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.078	$0.228	-	-	-	-	-	-	**$0.306**
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.

ARP-Collaboration

EXECUTIVE SUMMARY

Report Pulled: 4/23/2025 **Item ID: 8213**

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 &

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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$1.116	$1.186	$1.755	$1.535	$1.526	$1.303	-	-	$8.420
O&M	$0.127	$0.226	$0.222	$0.236	$0.214	$0.228	-	-	$1.254
Total Cost of Ownership	$1.243	$1.412	$1.978	$1.771	$1.740	$1.530	-	-	**$9.674**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.026	$0.154	$0.189	$0.181	$0.168	$0.168	-	-	**$0.886**
Outside Services	$0.437	$0.127	$0.267	$0.226	$0.223	$0.331	-	-	**$1.611**
Business Expense/Overheads	$0.010	$0.018	$0.031	$0.030	$0.029	$0.029	-	-	**$0.146**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.720	$1.113	$1.492	$1.335	$1.320	$1.003	-	-	**$6.981**
Licenses, Permits & Fees	$0.050	-	-	-	-	-	-	-	**$0.050**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.243	$1.412	$1.978	$1.771	$1.740	$1.530	-	-	**$9.674**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.127	$0.226	$0.222	$0.236	$0.214	$0.228	-	-	**$1.254**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.127	$0.226	$0.222	$0.236	$0.214	$0.228	-	-	**$1.254**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.116	$1.186	$1.755	$1.535	$1.526	$1.303	-	-	**$8.420**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.116	$1.186	$1.755	$1.535	$1.526	$1.303	-	-	**$8.420**
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 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

EXECUTIVE SUMMARY

Report Pulled: 4/23/2025 **Item ID: 8240**

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 M(

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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.445	-	-	-	-	-	-	-	$0.445
O&M	$0.019	-	-	-	-	-	-	-	$0.019
Total Cost of Ownership	$0.464	-	-	-	-	-	-	-	**$0.464**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.027	-	-	-	-	-	-	-	**$0.027**
Outside Services	$0.004	-	-	-	-	-	-	-	**$0.004**
Business Expense/Overheads	$0.006	-	-	-	-	-	-	-	**$0.006**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.331	-	-	-	-	-	-	-	**$0.331**
Licenses, Permits & Fees	$0.097	-	-	-	-	-	-	-	**$0.097**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.464	-	-	-	-	-	-	-	**$0.464**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.019	-	-	-	-	-	-	-	**$0.019**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.019	-	-	-	-	-	-	-	**$0.019**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.445	-	-	-	-	-	-	-	**$0.445**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.445	-	-	-	-	-	-	-	**$0.445**
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-Common

Report Pulled: 4/23/2025 **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 shared by Electric and Gas.

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

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

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) upgrading or replacing 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) upgrading or replacing 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) upgrading or replacing 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	$0.283	$1.719	$1.452	$0.749	$0.159	$0.348	-	-	$4.711
O&M	$0.025	$0.019	$0.017	$0.012	$0.006	$0.009	-	-	$0.088
Total Cost of Ownership	$0.308	$1.738	$1.469	$0.761	$0.165	$0.357	-	-	**$4.799**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.048	$0.093	$0.079	$0.044	$0.016	$0.032	-	-	**$0.312**
Outside Services	$0.002	$0.004	$0.004	$0.002	$0.001	$0.002	-	-	**$0.015**
Business Expense/Overheads	$0.014	$0.039	$0.033	$0.017	$0.005	$0.012	-	-	**$0.121**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.243	$1.601	$1.353	$0.698	$0.144	$0.312	-	-	**$4.351**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.308	$1.738	$1.469	$0.761	$0.165	$0.357	-	-	**$4.799**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.025	$0.019	$0.017	$0.012	$0.006	$0.009	-	-	**$0.088**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.025	$0.019	$0.017	$0.012	$0.006	$0.009	-	-	**$0.088**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.283	$1.719	$1.452	$0.749	$0.159	$0.348	-	-	**$4.711**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.283	$1.719	$1.452	$0.749	$0.159	$0.348	-	-	**$4.711**
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

EXECUTIVE SUMMARY

Report Pulled: 4/23/2025 **Item ID: 14029**

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 & STAN

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) upgrading or replacing 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) upgrading or replacing 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) upgrading or replacing 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	$0.075	$0.413	$0.466	$0.372	-	$0.521	-	-	$1.847
O&M	$0.005	$0.017	$0.019	$0.015	-	$0.022	-	-	$0.078
Total Cost of Ownership	$0.080	$0.429	$0.485	$0.388	-	$0.543	-	-	**$1.925**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.008	$0.040	$0.046	$0.037	-	$0.051	-	-	**$0.182**
Outside Services	$0.002	$0.002	$0.002	$0.002	-	$0.002	-	-	**$0.009**
Business Expense/Overheads	$0.002	$0.014	$0.016	$0.013	-	$0.018	-	-	**$0.064**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.068	$0.373	$0.421	$0.336	-	$0.471	-	-	**$1.669**
Licenses, Permits & Fees	-	$0.000	$0.000	$0.000	-	$0.000	-	-	**$0.001**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.080	$0.429	$0.485	$0.388	-	$0.543	-	-	**$1.925**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.005	$0.017	$0.019	$0.015	-	$0.022	-	-	**$0.078**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.005	$0.017	$0.019	$0.015	-	$0.022	-	-	**$0.078**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.075	$0.413	$0.466	$0.372	-	$0.521	-	-	**$1.847**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.075	$0.413	$0.466	$0.372	-	$0.521	-	-	**$1.847**
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-Field Device Asset Management (FDAM)

Report Pulled: 4/23/2025 **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 &

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 prior to increasing hardware failures; 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) use 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 to complete job tasks. It would also increase risk to our MPSC requirement to meet our meter reading factor and consecutive estimated targets and it could cause applications to run poorly or stop functioning; (2) purchase the newest 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$3.953	$3.250	$7.688	$5.845	$5.077	$3.493	-	-	$29.305
O&M	$0.003	$0.005	$0.005	$0.005	$0.005	$0.005	-	-	$0.028
Total Cost of Ownership	$3.956	$3.255	$7.693	$5.850	$5.082	$3.498	-	-	**$29.333**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.044	$0.055	$0.134	$0.097	$0.083	$0.055	-	-	**$0.469**
Outside Services	$0.055	-	-	-	-	-	-	-	**$0.055**
Business Expense/Overheads	$0.012	$0.026	$0.063	$0.046	$0.039	$0.026	-	-	**$0.211**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$3.845	$3.174	$7.495	$5.707	$4.959	$3.417	-	-	**$28.598**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$3.956	$3.255	$7.693	$5.850	$5.082	$3.498	-	-	**$29.333**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.003	$0.005	$0.005	$0.005	$0.005	$0.005	-	-	**$0.028**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.003	$0.005	$0.005	$0.005	$0.005	$0.005	-	-	**$0.028**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$3.953	$3.250	$7.688	$5.845	$5.077	$3.493	-	-	**$29.305**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$3.953	$3.250	$7.688	$5.845	$5.077	$3.493	-	-	**$29.305**
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-Local Area Network

Report Pulled: 4/23/2025 **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 &

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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$3.046	-	-	-	-	-	-	-	$3.046
O&M	$0.059	-	-	-	-	-	-	-	$0.059
Total Cost of Ownership	$3.105	-	-	-	-	-	-	-	**$3.105**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.475	-	-	-	-	-	-	-	**$0.475**
Outside Services	$0.276	-	-	-	-	-	-	-	**$0.276**
Business Expense/Overheads	$0.124	-	-	-	-	-	-	-	**$0.124**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$1.770	-	-	-	-	-	-	-	**$1.770**
Licenses, Permits & Fees	$0.460	-	-	-	-	-	-	-	**$0.460**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$3.105	-	-	-	-	-	-	-	**$3.105**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.059	-	-	-	-	-	-	-	**$0.059**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.059	-	-	-	-	-	-	-	**$0.059**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$3.046	-	-	-	-	-	-	-	**$3.046**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$3.046	-	-	-	-	-	-	-	**$3.046**
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: 4/23/2025 **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 shared by Electric and Gas.

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

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

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) to continue operating 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 of hardware failure and not having 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	$1.282	$0.834	$1.515	$0.797	$1.595	$15.890	-	-	$21.913
O&M	$0.111	$0.015	$0.025	$0.014	$0.027	$0.040	-	-	$0.231
Total Cost of Ownership	$1.393	$0.848	$1.540	$0.811	$1.622	$15.929	-	-	**$22.144**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.156	$0.038	$0.051	$0.027	$0.055	$0.203	-	-	**$0.530**
Outside Services	$0.079	$0.015	$0.028	$0.015	$0.030	$0.080	-	-	**$0.247**
Business Expense/Overheads	$0.050	$0.016	$0.020	$0.010	$0.022	$0.092	-	-	**$0.211**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$1.108	$0.771	$1.424	$0.752	$1.498	$15.512	-	-	**$21.064**
Licenses, Permits & Fees	-	$0.008	$0.017	$0.008	$0.017	$0.043	-	-	**$0.093**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$1.393	$0.848	$1.540	$0.811	$1.622	$15.929	-	-	**$22.144**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.111	$0.015	$0.025	$0.014	$0.027	$0.040	-	-	**$0.231**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.111	$0.015	$0.025	$0.014	$0.027	$0.040	-	-	**$0.231**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$1.282	$0.834	$1.515	$0.797	$1.595	$15.890	-	-	**$21.913**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$1.282	$0.834	$1.515	$0.797	$1.595	$15.890	-	-	**$21.913**
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: 4/23/2025 | 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 & STANI

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) to continue operating 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 of hardware failure and not having 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	$0.425	$0.066	$0.022	$0.106	$0.118	$7.579	-	-	$8.317
O&M	$0.024	$0.001	$0.001	$0.002	$0.002	$0.008	-	-	$0.037
Total Cost of Ownership	$0.448	$0.067	$0.023	$0.108	$0.120	$7.587	-	-	**$8.354**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.033	$0.005	$0.002	$0.004	$0.007	$0.207	-	-	**$0.259**
Outside Services	$0.006	$0.001	$0.000	$0.002	$0.002	$0.052	-	-	**$0.064**
Business Expense/Overheads	$0.011	$0.002	$0.001	$0.002	$0.003	$0.098	-	-	**$0.117**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.398	$0.059	$0.020	$0.100	$0.107	$7.219	-	-	**$7.901**
Licenses, Permits & Fees	$0.000	$0.000	$0.000	$0.000	$0.001	$0.012	-	-	**$0.013**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.448	$0.067	$0.023	$0.108	$0.120	$7.587	-	-	**$8.354**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.024	$0.001	$0.001	$0.002	$0.002	$0.008	-	-	**$0.037**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.024	$0.001	$0.001	$0.002	$0.002	$0.008	-	-	**$0.037**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.425	$0.066	$0.022	$0.106	$0.118	$7.579	-	-	**$8.317**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.425	$0.066	$0.022	$0.106	$0.118	$7.579	-	-	**$8.317**
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-Operational Technology Support Common

Report Pulled: 4/23/2025 **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 5 year refresh schedule.

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

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

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 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	$0.260	-	$0.187	-	-	-	-	-	$0.446
O&M	$0.007	-	$0.005	-	-	-	-	-	$0.012
Total Cost of Ownership	$0.266	-	$0.192	-	-	-	-	-	**$0.458**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.013	-	$0.010	-	-	-	-	-	**$0.022**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.003	-	$0.002	-	-	-	-	-	**$0.006**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.248	-	$0.178	-	-	-	-	-	**$0.426**
Licenses, Permits & Fees	$0.003	-	$0.002	-	-	-	-	-	**$0.005**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.266	-	$0.192	-	-	-	-	-	**$0.458**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.007	-	$0.005	-	-	-	-	-	**$0.012**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.007	-	$0.005	-	-	-	-	-	**$0.012**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.260	-	$0.187	-	-	-	-	-	**$0.446**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.260	-	$0.187	-	-	-	-	-	**$0.446**
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: 4/23/2025 **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 5 year refresh schedule.

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

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

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 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$2.245	$0.056	$1.169	$0.917	-	-	-	-	$4.386
O&M	$0.022	$0.003	$0.021	$0.019	-	-	-	-	$0.065
Total Cost of Ownership	$2.267	$0.059	$1.189	$0.936	-	-	-	-	**$4.451**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.037	$0.009	$0.148	$0.055	-	-	-	-	**$0.248**
Outside Services	$0.044	-	-	-	-	-	-	-	**$0.044**
Business Expense/Overheads	$0.007	$0.002	$0.042	$0.015	-	-	-	-	**$0.066**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$1.968	$0.047	$0.995	$0.860	-	-	-	-	**$3.870**
Licenses, Permits & Fees	$0.210	$0.001	$0.005	$0.006	-	-	-	-	**$0.222**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$2.267	$0.059	$1.189	$0.936	-	-	-	-	**$4.451**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.022	$0.003	$0.021	$0.019	-	-	-	-	**$0.065**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.022	$0.003	$0.021	$0.019	-	-	-	-	**$0.065**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$2.245	$0.056	$1.169	$0.917	-	-	-	-	**$4.386**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$2.245	$0.056	$1.169	$0.917	-	-	-	-	**$4.386**
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: 4/23/2025 **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 M

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, 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.

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 reducing 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) 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 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 concerns, incident 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.

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	$2.282	$1.528	$2.113	$2.114	$2.114	$2.114	-	-	$12.266
O&M	$0.014	$0.013	$0.013	$0.013	$0.013	$0.013	-	-	$0.077
Total Cost of Ownership	$2.296	$1.541	$2.125	$2.127	$2.127	$2.127	-	-	**$12.343**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.020	$0.128	$0.164	$0.164	$0.164	$0.164	-	-	**$0.803**
Outside Services	$0.656	$0.454	$0.589	$0.589	$0.589	$0.589	-	-	**$3.466**
Business Expense/Overheads	$(0.240)	$(0.040)	$0.074	$0.074	$0.074	$0.074	-	-	**$0.017**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$1.860	$0.999	$1.299	$1.300	$1.300	$1.300	-	-	**$8.057**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$2.296	$1.541	$2.125	$2.127	$2.127	$2.127	-	-	**$12.343**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.014	$0.013	$0.013	$0.013	$0.013	$0.013	-	-	**$0.077**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.014	$0.013	$0.013	$0.013	$0.013	$0.013	-	-	**$0.077**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$2.282	$1.528	$2.113	$2.114	$2.114	$2.114	-	-	**$12.266**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$2.282	$1.528	$2.113	$2.114	$2.114	$2.114	-	-	**$12.266**
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: 4/23/2025 **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

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.

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 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.

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	$1.081	$1.521	$0.182	$0.675	$0.235	$1.077	-	-	$4.772
O&M	-	$0.005	$0.005	$0.005	$0.005	$0.005	-	-	$0.025
Total Cost of Ownership	$1.081	$1.526	$0.187	$0.680	$0.240	$1.082	-	-	**$4.797**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.065	$0.030	$0.002	$0.011	$0.006	$0.031	-	-	**$0.145**
Outside Services	$0.008	-	-	-	-	-	-	-	**$0.008**
Business Expense/Overheads	$0.015	$0.014	$0.001	$0.005	$0.001	$0.015	-	-	**$0.050**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.994	$1.483	$0.185	$0.664	$0.233	$1.036	-	-	**$4.595**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.081	$1.526	$0.187	$0.680	$0.240	$1.082	-	-	**$4.797**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.005	$0.005	$0.005	$0.005	$0.005	-	-	**$0.025**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.005	$0.005	$0.005	$0.005	$0.005	-	-	**$0.025**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.081	$1.521	$0.182	$0.675	$0.235	$1.077	-	-	**$4.772**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.081	$1.521	$0.182	$0.675	$0.235	$1.077	-	-	**$4.772**
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' 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.
Technology Capability	The PAM program supports Engineering Design Process (Redline/Green Line Drawings); Storm Restoration (Hard Print for Damage Assessment). The daily print operations for Business Partners to complete their work as it relates to storms restorations, projects, D & E renderings and application process work.

ARP-Radio

Report Pulled: 4/23/2025 **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 5-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle.

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

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

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, 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.

Alternatives 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.

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	$1.165	$2.940	$1.995	$1.977	$2.014	$2.487	-	-	$12.578
O&M	$0.094	$0.114	$0.222	$0.202	$0.171	$0.090	-	-	$0.893
Total Cost of Ownership	$1.259	$3.055	$2.217	$2.179	$2.186	$2.577	-	-	**$13.472**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$(0.206)	$0.114	$0.109	$0.098	$0.121	$0.082	-	-	**$0.317**
Outside Services	$0.381	$0.483	$0.483	$0.483	$0.483	$0.523	-	-	**$2.836**
Business Expense/Overheads	$0.018	$0.074	$0.078	$0.074	$0.085	$0.073	-	-	**$0.401**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$1.066	$2.383	$1.548	$1.524	$1.497	$1.899	-	-	**$9.917**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.259	$3.055	$2.217	$2.179	$2.186	$2.577	-	-	**$13.472**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.094	$0.114	$0.222	$0.202	$0.171	$0.090	-	-	**$0.893**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.094	$0.114	$0.222	$0.202	$0.171	$0.090	-	-	**$0.893**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.165	$2.940	$1.995	$1.977	$2.014	$2.487	-	-	**$12.578**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.165	$2.940	$1.995	$1.977	$2.014	$2.487	-	-	**$12.578**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

ARP-Radio | **Report Pulled: 4/23/2025** | **Item ID: 8234**

EXECUTIVE SUMMARY

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 (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: 4/23/2025 **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 > * > * > *

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

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 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. If the Digital-Hybrid Cloud and Data Center Migration project is not approved as part of this rate case, the Company plans to continue to refresh these critical technologies at the current level based on a five- to seven-year refresh cycle to mitigate the risk of failure.

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	$0.701	-	-	$1.416	$1.965	-	-	-	$4.082
O&M	$0.093	-	-	$0.117	$0.014	-	-	-	$0.224
Total Cost of Ownership	$0.793	-	-	$1.532	$1.979	-	-	-	**$4.305**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.064	-	-	$0.200	$0.135	-	-	-	**$0.399**
Outside Services	$0.067	-	-	$0.100	-	-	-	-	**$0.167**
Business Expense/Overheads	$0.006	-	-	$0.136	$0.094	-	-	-	**$0.236**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.653	-	-	$1.097	$1.750	-	-	-	**$3.499**
Licenses, Permits & Fees	$0.004	-	-	-	-	-	-	-	**$0.004**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.793	-	-	$1.532	$1.979	-	-	-	**$4.305**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.093	-	-	$0.117	$0.014	-	-	-	**$0.224**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.093	-	-	$0.117	$0.014	-	-	-	**$0.224**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.701	-	-	$1.416	$1.965	-	-	-	**$4.082**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.701	-	-	$1.416	$1.965	-	-	-	**$4.082**
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: 4/23/2025 **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 > * > * > *

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

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: (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.

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	$5.993	$8.681	$6.153	$6.927	$10.968	$11.162	-	-	$49.883
O&M	$0.028	$0.090	$0.061	$0.071	$0.087	$0.109	-	-	$0.446
Total Cost of Ownership	$6.021	$8.770	$6.214	$6.997	$11.055	$11.271	-	-	**$50.329**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.222	$0.215	$0.145	$0.139	$0.178	$0.216	-	-	**$1.115**
Outside Services	$0.011	$0.127	$0.085	$0.081	$0.104	$0.127	-	-	**$0.534**
Business Expense/Overheads	$0.054	$0.108	$0.073	$0.070	$0.089	$0.108	-	-	**$0.502**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$5.735	$8.320	$5.911	$6.708	$10.684	$10.820	-	-	**$48.178**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$6.021	$8.770	$6.214	$6.997	$11.055	$11.271	-	-	**$50.329**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.028	$0.090	$0.061	$0.071	$0.087	$0.109	-	-	**$0.446**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.028	$0.090	$0.061	$0.071	$0.087	$0.109	-	-	**$0.446**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$5.993	$8.681	$6.153	$6.927	$10.968	$11.162	-	-	**$49.883**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$5.993	$8.681	$6.153	$6.927	$10.968	$11.162	-	-	**$49.883**
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: 4/23/2025 **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 our current 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 > * > * > *

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

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 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 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 solution with market leaders; (2) upgrading the vendor software from the current version to the newer SaaS version or replacing it.

Alternatives

Alternatives considered include: (1) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (2) Do nothing and remain on unsupported, on-prem tax solution. This option introduces technical and financial risk which would be costly; (3) Upgrade to the newest SaaS version of current on-prem 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**
2/1/2027	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	$0.368	$0.307	$0.254	$0.254	$0.254	-	-	-	$1.439
Total Cost of Ownership	$0.368	$0.307	$0.254	$0.254	$0.254	-	-	-	**$1.439**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.099	$0.025	-	-	-	-	-	-	**$0.124**
Outside Services	$0.199	$0.025	-	-	-	-	-	-	**$0.223**
Business Expense/Overheads	$0.021	$0.003	-	-	-	-	-	-	**$0.024**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.050	$0.254	$0.254	$0.254	$0.254	-	-	-	**$1.067**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.368	$0.307	$0.254	$0.254	$0.254	-	-	-	**$1.439**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.368	$0.307	$0.254	$0.254	$0.254	-	-	-	**$1.439**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.368	$0.307	$0.254	$0.254	$0.254	-	-	-	**$1.439**
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

Report Pulled: 4/23/2025 **Item ID: 10473**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Asset Accounting Upgrade

Description 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.

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

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

WORK OBJECTIVES

Problem Statement

In 2022, 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. The current monthly allocation process has limited visibility to Company financial performance, and the upgrade provides functionality that allows more frequent allocation processes. Additionally, implementing the vendor's regulatory module eliminates the time-consuming and labor-intensive process of manual data extracts for regulatory analysis used for Cost of Service modeling.

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) eliminating the labor intensive and time-consuming process of pulling data for regulatory analysis used for Cost of Service; (3) automating manual tasks; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.

Scope

The project scope includes: (1) upgrading the vendor software from the current version to the newer version; (2) implementing new functionality that includes features for the regulatory Cost of Service analysis, additional reporting, job scheduling, and centralized error processing; and (3) populating the data lake with data from the asset accounting system for improved reporting.

Alternatives

Alternatives considered include: (1) Upgrade to the newest, cloud version of PowerPlan. 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. (2) Evaluate 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 likely be more complex, cost more, and may not provide all the required features. (3) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/19/2021	2/17/2022	6/23/2022	10/12/2022
	In-Service/Go-Live	**Closeout**	
	10/13/2022	2/28/2023	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$0.926	$2.892	$0.812	-	-	-	-	-	$4.631
O&M	$0.032	$0.086	$0.115	$0.027	$0.050	$0.050	$0.050	-	$0.410
Total Cost of Ownership	$0.959	$2.978	$0.927	$0.027	$0.050	$0.050	$0.050	-	**$5.041**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.031	$0.338	$0.213	-	-	-	-	-	**$0.582**
Outside Services	$0.924	$1.485	$0.569	$0.027	-	-	-	-	**$3.005**
Business Expense/Overheads	$0.004	$0.229	$0.145	-	-	-	-	-	**$0.378**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.925	-	-	-	-	-	-	**$0.925**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.959	$2.978	$0.927	$0.027	-	-	-	-	**$4.891**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	$(0.010)	$(0.010)	$(0.010)	$(0.010)	$(0.010)	-	**$(0.050)**
	Initial	$0.032	$0.086	$0.115	$0.027	$0.050	$0.050	$0.050	-	**$0.410**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.032	$0.086	$0.105	$0.017	$0.040	$0.040	$0.040	-	**$0.360**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.926	$2.892	$0.812	-	-	-	-	-	**$4.631**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.926	$2.892	$0.812	-	-	-	-	-	**$4.631**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.993

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Asset Accounting Upgrade | **Report Pulled: 4/23/2025** | **Item ID: 10473**

EXECUTIVE SUMMARY

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.
Intangibles	The Property Accounting area will eliminate waste and increase productivity by eliminating the labor intensive and time-consuming process of pulling data for regulatory analysis used to determine Cost of Service.
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: 4/23/2025 **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 our 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 on an undisclosed timeline. 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) Evaluate 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) 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) Analyze and go to cloud possibilities (4) wait until a future upgrade cycle; (5) 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	$0.558	$0.066	-	-	-	-	-	-	$0.624
Total Cost of Ownership	$0.558	$0.066	-	-	-	-	-	-	**$0.624**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.149	$0.012	-	-	-	-	-	-	**$0.161**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	$0.409	$0.054	-	-	-	-	-	-	**$0.463**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.558	$0.066	-	-	-	-	-	-	**$0.624**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.558	$0.066	-	-	-	-	-	-	**$0.624**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.558	$0.066	-	-	-	-	-	-	**$0.624**
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: 4/23/2025 **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 our 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 on an undisclosed timeline. 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 a newer version.

Alternatives

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 PowerPlan, 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) 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) Upgrade 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	$0.558	$0.066	-	-	-	-	-	-	$0.624
Total Cost of Ownership	$0.558	$0.066	-	-	-	-	-	-	**$0.624**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.149	$0.012	-	-	-	-	-	-	**$0.161**
Outside Services	$0.372	$0.050	-	-	-	-	-	-	**$0.422**
Business Expense/Overheads	$0.037	$0.004	-	-	-	-	-	-	**$0.041**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.558	$0.066	-	-	-	-	-	-	**$0.624**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.558	$0.066	-	-	-	-	-	-	**$0.624**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.558	$0.066	-	-	-	-	-	-	**$0.624**
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: 4/23/2025 **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 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.

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

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

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	$0.074	-	-	-	-	-	-	-	$0.074
Total Cost of Ownership	$0.074	-	-	-	-	-	-	-	**$0.074**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.041	-	-	-	-	-	-	-	**$0.041**
Outside Services	$0.027	-	-	-	-	-	-	-	**$0.027**
Business Expense/Overheads	-	-	-	-	-	-	-	-	-
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.005	-	-	-	-	-	-	-	**$0.005**
Licenses, Permits & Fees	$0.000	-	-	-	-	-	-	-	**$0.000**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.074	-	-	-	-	-	-	-	**$0.074**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.074	-	-	-	-	-	-	-	**$0.074**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.074	-	-	-	-	-	-	-	**$0.074**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

AxWay Secure Transport 2024 Upgrade

Report Pulled: 4/23/2025 **Item ID: 11748**

EXECUTIVE SUMMARY

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: 4/23/2025 **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 CE 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.

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

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

WORK OBJECTIVES

Problem Statement As Axway SecureTransport 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 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. (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	$0.395	-	-	-	-	-	-	-	$0.395
Total Cost of Ownership	$0.395	-	-	-	-	-	-	-	**$0.395**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.369	-	-	-	-	-	-	-	**$0.369**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.026	-	-	-	-	-	-	-	**$0.026**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.395	-	-	-	-	-	-	-	**$0.395**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.395	-	-	-	-	-	-	-	**$0.395**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.395	-	-	-	-	-	-	-	**$0.395**
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.

Business Continuity - Program Management Tool

Report Pulled: 4/23/2025 **Item ID: 12679**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Business Continuity - Disaster Recovery Planning Tool, Business Continuity - Program Management Tool

Description The Business Continuity Program Management Tool is critical for successful and effective Business Continuity, Disaster Recovery, and Emergency Management Programs. The software tool will provide automation, enhance the Company's incident management processes, establish critical linkages between departments and essential functions they support, and will perform necessary analysis before, during, and after a disruption that allows for the efficient response to minimize downtime.

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

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

WORK OBJECTIVES

Problem Statement The current business continuity and disaster recovery program management tool does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. The current tool limits automation opportunities and has gaps in how it handles template enhancements, which results in the need for manual workarounds in order to prevent losing critical data. The lack of capability affects reporting, upstream / downstream impact mapping, Incident Command System (ICS) documentation automation, and user administration.

Objectives This project will create value for the Company by: (1) maintaining the documentation that supports the recovery efforts of critical processes and associated essential functions that, if disrupted, would present significant impact to the Company and customers; (2) limiting business and community impact while providing a critical energy service; (3) prioritization of the recovery of critical processes and resource allocation during a business continuity incident(s); (4) providing a consistent, organized and expedient response process (Incident Command System) that is flexible to meet the needs of any incident, regardless of severity or scope; (5) providing a mechanism for identifying restorations gaps between critical business processes and IT recovery capabilities; (6) reducing or eliminating human error and waste; and (7) improved and more efficient user experience.

Scope The project scope includes: (1) framework for the development and maintenance of Business Continuity, System (Application) Recovery Plans, Incident Command System, and Disaster Recovery Plans that are effective and easily accessible during an event; (2) automation for reporting to track status and to measure effectiveness and maturity of the program (Business Continuity, Emergency Management, Disaster Recovery Programs); (3) component for facilitating effective training exercises and response efforts through incident management tools that utilize concepts from the Federal Emergency Management Agency (FEMA) National Incident Management System (NIMS); (4) program management tools to monitor required program deliverables; (5) template for developing and maintaining site hazard assessments; (6) dependency mapping of critical business processes and IT applications; and (7) integrated business impact analysis process.

Alternatives Alternatives considered include: (1) continue to use Riskonnect (current Disaster Recovery tool). This alternative was not selected because it currently does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. (2) Revert back to manual process. This alternative was not selected because the manual process is time consuming; and leads to human struggle and duplicative work. A previous KPMG Audit of the Business Continuity Program indicated the need for interdependency mapping and a software tool is the best way to accomplish this. (3) Implement a best-in-class Cloud Software as a Service (SaaS) solution to address the current incident management gaps and provide a consistent, organized, and expedient response process that supports the FEMA Incident Command System (ICS). This alternative was selected because there are better SaaS solutions that fit the needs outlined above.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
5/2/2026	7/2/2026	8/6/2026	1/5/2027
	In-Service/Go-Live	**Closeout**	
	2/2/2027	3/2/2027	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	-	$0.100	$0.045	-	-	-	-	-	$0.145
Total Cost of Ownership	-	$0.100	$0.045	-	-	-	-	-	**$0.145**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.069	$0.017	-	-	-	-	-	**$0.086**
Outside Services	-	$0.025	$0.025	-	-	-	-	-	**$0.050**
Business Expense/Overheads	-	$0.007	$0.003	-	-	-	-	-	**$0.009**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.100	$0.045	-	-	-	-	-	**$0.145**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.100	$0.045	-	-	-	-	-	**$0.145**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.100	$0.045	-	-	-	-	-	**$0.145**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Business Continuity - Program Management Tool

Report Pulled: 4/23/2025 **Item ID: 12679**

EXECUTIVE SUMMARY

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	A new tool leveraging automation would enable Emergency Management Department to save 376 labor hours annually. Calculation: once per quarter, 12 hours is spent going through data for 99 departments to ensure program deliverables are on track. On average 6 hours a week is composing follow-up emails and updating the tracking spreadsheet. About 2-4 hours each quarter is spent formatting the tracking dashboard for management accountability.
Intangibles	Cloud allows for maintenance, upgrades, and patching with no employee/contractor down time.
Risk Mitigation	Having an incident management component enables direct connection to emergency response plans and business continuity plans to facilitate a more efficient response. Incident Command System forms and tools that are integrated will save time and provide clear and concise reporting and recordkeeping. Current planning documentation for incidents is challenging to use, format, produce actionable plans, and get approvals. Current recordkeeping is very manual. This tool will provide a one-stop repository for planning, delivering the plans, recording the progress through multiple operational periods of an incident, and housing records. It will enable improved after-action reporting, tracking, and follow-up such as after-action task assignment, completion date tracking and assignment, late task completion escalation, advanced management-level reporting, and integration to other work management systems such as ServiceNow and SAP to enable pre-populating forms for incidents that begin in other work management applications.
Risk Mitigation	Having cloud with break glass accounts enables the company to access Emergency Response Plans (ERPs), Incident Command System (ICS) forms, and Business Continuity/Disaster Recovery Plans from any device in an event. Break glass accounts are native to the solution that is not managed within CE authentication so if CE gets hit with a ransomware attack or some other event that disables the network, these accounts can be used to still access the tool to get to the plans to assist with recovery.
Intangibles	If no tool is selected to replace the existing SaaS solution and the Company resorted to manual paper processes, Consumers Energy (CE) would have a higher risk of not being able to access mission-critical documentation during events. For Business Continuity, CE would not be able to mature the program and existing programs and preparedness/recovery gaps would remain.

Cascade Modernization and Prioritization

Report Pulled: 4/23/2025 **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	$0.086	-	-	-	-	-	-	$0.374
O&M	$0.006	$0.063	$0.052	$0.052	$0.001	-	-	-	$0.174
Total Cost of Ownership	$0.293	$0.150	$0.052	$0.052	$0.001	-	-	-	**$0.548**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.021	$0.062	-	-	-	-	-	-	**$0.083**
Outside Services	$0.264	$0.014	-	-	-	-	-	-	**$0.278**
Business Expense/Overheads	$0.008	$0.022	-	-	-	-	-	-	**$0.030**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.051	$0.051	$0.051	-	-	-	-	**$0.154**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.293	$0.150	$0.051	$0.051	-	-	-	-	**$0.546**

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	$0.063	$0.052	$0.052	$0.001	-	-	-	**$0.174**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$(0.473)	$(0.416)	$0.052	$0.052	$0.001	-	-	-	**$(0.784)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.287	$0.086	-	-	-	-	-	-	**$0.374**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.287	$0.086	-	-	-	-	-	-	**$0.374**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	0.581

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: 4/23/2025 **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	$1.199	$0.527	-	-	-	-	-	$2.422
O&M	$0.031	$0.295	$0.386	$0.300	$0.300	$0.300	-	-	$1.611
Total Cost of Ownership	$0.726	$1.494	$0.913	$0.300	$0.300	$0.300	-	-	**$4.033**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.186	$0.910	$0.400	-	-	-	-	-	**$1.496**
Outside Services	$0.486	-	-	-	-	-	-	-	**$0.486**
Business Expense/Overheads	$0.054	$0.484	$0.213	-	-	-	-	-	**$0.751**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.726	$1.394	$0.613	-	-	-	-	-	**$2.733**

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	$0.295	$0.386	$0.300	$0.300	$0.300	-	-	**$1.611**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.031	$0.295	$(3.350)	$(4.681)	$(4.681)	$(4.681)	$(1.245)	-	**$(18.311)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.695	$1.199	$0.527	-	-	-	-	-	**$2.422**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.695	$1.199	$0.527	-	-	-	-	-	**$2.422**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	2.930

Catastrophic Crewing (CatCrew) Version 2.0

Report Pulled: 4/23/2025 **Item ID: 12558**

EXECUTIVE SUMMARY

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: 4/23/2025 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 most 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 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 our 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 our critical substation increasing the risk for large scale outages and customer impact. Our 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, we are vulnerable to an adversary causing destruction without knowledge of when or how the event took place. Consumers Energy would take a phased implementation approach to further 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 our electric substations in real-time. This enhanced security posture will align with other utilities that own and operate substations and mitigate disruption to the electric 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; (8) security equipment maintenance. These activities will be performed at the following company locations: Acme (Acme), Algoma (Sparta), Alma (Alma), Amber (Ludington), Barry (Hastings), Beals Road (Wyoming), Beecher (Adrian), Beveridge (Flint), Blackstone (Jackson), Boardman (Traverse City), Brickyard (Holton), Broadmoor (Grand Rapids), Campbell (West Olive), Cannon (Rockford), Cement City (Cement City), Churchill (Leslie), Clearwater (Kalkaska), Cleveland (Spring Lake), Cole Creek (Flushing), Crescent (Hillsdale), Croton Dam (Newaygo), David (Pewamo), Deja (Edmore), Dort (Mt. Morris), Dowling (Hudson), Edenville Dam (Hope), Edwards (Kalamazoo), Ellsworth (Grand Rapids), Elm Street (Battle Creek), Eureka (Greenville), Farr Road (Onekama), Gleaner (Freeland), Gratiot Farms (Middleton), Grodi Road (Erie), Grout (Gladwin), Hazelwood (Plainwell), Hemphill (Flint), Hile Road (Muskegon), Hodenpyl Dam (Wexford), Holland Road (Saginaw), HSC Hemlock Semiconductor (Hemlock), Hughes Road (Marshall), Island Road (Charlotte), Jackson Plymouth (Jackson), Lafayette (Battle Creek), Layton (Chesaning), Lindbergh (Kalamazoo), Looking Glass (Lansing), Manlius (New Richmond), McNally (Charlevoix), Miles Road (East Jordan), Monitor (Bay City), Moore Road (Hillsdale), Morrow (Comstock), Muskegon Heights (Muskegon), Oceana (Hart), Ogemaw (West Branch), Page Avenue (Jackson), Pasadena (Flint), Pingree (Allendale), Raisin (Tecumseh), Rice Creek (Albion), Riverview (Kalamazoo), Silicon Hemlock Semiconductor (Hemlock), Simpson (Mendon), Sonoma (Battle Creek), Spartan (East Lansing), Thompson Road (Clarksville), Trowbridge (Allegan), Twining (Twining), Vernon (Clare), VeVay (Mason), Vrooman (Jackson), Washtenaw (Chelsea), Wealthy (Grand Rapids), and Willard (Birch Run).

Alternatives Alternatives considered include: (1) maintain the current security perimeter fencing and conduct 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) implement enhanced security measures at the most critical substations in order to prevent unauthorized access, deter criminal activity, and respond to threats in real-time.

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

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$2.956	$4.584	$4.584	-	-	-	-	-	$12.123
O&M	$0.350	$0.490	$0.490	-	-	-	-	-	$1.330
Total Cost of Ownership	$3.306	$5.074	$5.074	-	-	-	-	-	**$13.453**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.750	$1.350	$1.350	-	-	-	-	-	**$3.450**
Outside Services	$1.563	$2.563	$2.563	-	-	-	-	-	**$6.688**
Business Expense/Overheads	$0.681	$0.849	$0.849	-	-	-	-	-	**$2.378**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.313	$0.313	$0.313	-	-	-	-	-	**$0.938**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.306	$5.074	$5.074	-	-	-	-	-	**$13.453**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.350	$0.490	$0.490	-	-	-	-	-	**$1.330**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.350	$0.490	$0.490	-	-	-	-	-	**$1.330**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.956	$4.584	$4.584	-	-	-	-	-	**$12.123**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.956	$4.584	$4.584	-	-	-	-	-	**$12.123**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Critical Substation Upgrade

EXECUTIVE SUMMARY

Report Pulled: 4/23/2025

Item ID: 13388

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Customer Order Service Tracker

Report Pulled: 4/23/2025 **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	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/10/2025	4/11/2025	6/13/2025	6/26/2026
	In-Service/Go-Live	**Closeout**	
	8/28/2026	11/20/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$2.413	$1.609	-	-	-	-	-	$4.022
O&M	-	$0.562	$0.375	$0.050	$0.050	$0.050	$0.050	$0.050	$1.186
Total Cost of Ownership	-	$2.975	$1.983	$0.050	$0.050	$0.050	$0.050	$0.050	**$5.208**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.900	$0.600	-	-	-	-	-	**$1.500**
Outside Services	-	$1.200	$0.800	$0.050	$0.050	$0.050	$0.050	$0.050	**$2.250**
Business Expense/Overheads	-	$0.875	$0.583	-	-	-	-	-	**$1.458**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$2.975	$1.983	$0.050	$0.050	$0.050	$0.050	$0.050	**$5.208**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.562	$0.375	$0.050	$0.050	$0.050	$0.050	$0.050	**$1.186**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.562	$0.375	$0.050	$0.050	$0.050	$0.050	$0.050	**$1.186**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$2.413	$1.609	-	-	-	-	-	**$4.022**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$2.413	$1.609	-	-	-	-	-	**$4.022**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Customer Order Service Tracker

Report Pulled: 4/23/2025 **Item ID: 9062**

EXECUTIVE SUMMARY

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: 4/23/2025 **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 Data Lake 2.0 (DL 2.0), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems including SingleStore Data Lake (SSDL), SAP Business Warehouse (BW), SAP Business Objects (BOBJ), Native HANA, the BW Portal, and SAP Business Objects Data Services (BODS) creates value by reducing the total cost of ownership associated with maintaining and supporting legacy systems.

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

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

WORK OBJECTIVES

Problem Statement 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.

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	7/31/2026
	In-Service/Go-Live	**Closeout**	
	8/14/2026	9/18/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$3.132	$6.870	-	-	-	-	-	-	$10.002
O&M	$0.357	$1.304	-	-	-	-	-	-	$1.661
Total Cost of Ownership	$3.489	$8.174	-	-	-	-	-	-	**$11.663**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$1.100	$2.200	-	-	-	-	-	-	**$3.300**
Outside Services	$1.750	$4.090	-	-	-	-	-	-	**$5.840**
Business Expense/Overheads	$0.539	$1.078	-	-	-	-	-	-	**$1.617**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	$0.100	$0.806	-	-	-	-	-	-	**$0.906**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$3.489	$8.174	-	-	-	-	-	-	**$11.663**

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	$0.357	$1.304	-	-	-	-	-	-	**$1.661**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$(0.253)	$(1.725)	$(2.427)	$(2.436)	$(2.445)	$(2.454)	-	-	**$(11.739)**
Cap+COR	Reduction	$(0.300)	-	$(2.000)	$(2.000)	-	-	-	-	**$(4.300)**
	Initial	$3.132	$6.870	-	-	-	-	-	-	**$10.002**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$2.832	$6.870	$(2.000)	$(2.000)	-	-	-	-	**$5.702**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) 0.223

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Attraction and Retention of High Performir	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 Re	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: 4/23/2025 **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 & SEI

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	-	-	-	-	-	-	$12.369
O&M	$0.197	$1.062	$1.588	$1.588	$1.588	-	-	-	$6.023
Total Cost of Ownership	$3.539	$10.089	$1.588	$1.588	$1.588	-	-	-	**$18.392**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.726	$1.298	-	-	-	-	-	-	**$2.023**
Outside Services	$1.912	$7.906	-	-	-	-	-	-	**$9.818**
Business Expense/Overheads	$0.253	$0.408	$0.084	$0.084	$0.084	-	-	-	**$0.915**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.118	-	-	-	-	-	-	**$0.118**
Licenses, Permits & Fees	$0.648	$0.358	-	-	-	-	-	-	**$1.007**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.539	$10.089	$0.084	$0.084	$0.084	-	-	-	**$13.881**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.197	$1.062	$1.588	$1.588	$1.588	-	-	-	**$6.023**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.197	$1.062	$1.588	$1.588	$1.588	-	-	-	**$6.023**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$3.342	$9.027	-	-	-	-	-	-	**$12.369**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$3.342	$9.027	-	-	-	-	-	-	**$12.369**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Digital-Cloud Data and Analytics Platform

EXECUTIVE SUMMARY

Report Pulled: 4/23/2025 **Item ID: 13443**

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: 4/23/2025 **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

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 in leveraging public cloud services; and (12) transforming IT to become the broker of cloud services for the Company.

Alternatives 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.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/1/2023	4/15/2023	8/15/2023	10/1/2025
	In-Service/Go-Live	**Closeout**	
	12/1/2025	12/15/2025	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	$2.779	$2.425	$1.776	-	-	-	-	$6.980
O&M	-	$0.529	$0.783	$0.580	$10.188	$10.450	$9.620	$20.082	$52.232
Total Cost of Ownership	-	$3.308	$3.207	$2.356	$10.188	$10.450	$9.620	$20.082	**$59.211**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	-	$0.372	$1.004	$1.510	-	-	-	-	**$2.885**
Outside Services	-	$1.062	$1.760	-	-	-	-	-	**$2.822**
Business Expense/Overheads	-	$0.157	$0.222	$0.667	-	-	-	-	**$1.046**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	$0.379	$(0.074)	-	-	-	-	-	**$0.304**
Licenses, Permits & Fees	-	$1.339	$0.296	$0.180	$1.100	$1.100	-	-	**$4.015**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$3.308	$3.207	$2.356	$1.100	$1.100	-	-	**$11.072**

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	$0.580	$10.188	$10.450	$9.620	$20.082	**$52.232**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	$(0.094)	$(0.600)	$(3.643)	$4.180	$4.262	$3.246	$8.014	**$15.365**
Cap+COR	Reduction	-	$(5.624)	$(2.677)	$(3.155)	$(5.820)	$(5.995)	$(4.175)	$(12.910)	**$(40.356)**
	Initial	-	$2.779	$2.425	$1.776	-	-	-	-	**$6.980**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	$(2.845)	$(0.252)	$(1.379)	$(5.820)	$(5.995)	$(4.175)	$(12.910)	**$(33.376)**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

Digital-Hybrid Cloud and Data Center Migration

Report Pulled: 4/23/2025 **Item ID: 10502**

EXECUTIVE SUMMARY

B/C Ratio (Overall)	0.391

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.

Digital-Infrastructure Automation

Report Pulled: 4/23/2025 **Item ID: 13437**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Digital - Infrastructure Automation, Digital-Infrastructure Automation

Description This project will automate the deployment, maintenance, and tear down or decommissioning of cloud and data center services, leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services while reducing operational costs.

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

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

WORK OBJECTIVES

Problem Statement

As the company uses cloud services to provide infrastructure for applications, the difficulty of manually deploying, maintaining, and decommissioning infrastructure, improving efficiency of the use of infrastructure, bolstering resiliency, maintaining security posture, and extending new capabilities increases significantly. The manual approach lengthens application implementation times and leads to inconsistent and/or incorrect deployment of infrastructure.

Objectives

This project will create value by ensuring the Company's application infrastructure requirements are met through automation. Specifically, the project will create automation to deploy, maintain, and deprovision infrastructure in a modular fashion to be used by product teams to deploy, maintain, upgrade, and deprovision Company applications. Thus, the project will: (1) improve the efficiency of the use of infrastructure by allowing for infrastructure to be provisioned when needed, and deprovisioned when not needed; (2) bolster the resiliency of infrastructure by creating reusable resilient patterns and scalability for applications to use; (3) deploying and removing infrastructure securely; and (4) enhancing or extending automation for new cloud and data center services to support Company applications.

Scope

The project scope includes: (1) procuring automation software; (2) building automation for cloud and data center services; (3) building resiliency and scalability into the services; (4) building security posture into the services; and (5) enhancing existing or extending automation for new services.

Alternatives

Alternatives considered include: (1) manually deploying, maintaining, and decommissioning infrastructure to support Company applications. This alternative was not chosen because it has proven to be slow, costly, and error-prone; (2) manually improving the efficiency in the use of infrastructure. This alternative was not chosen because the Company does not have the necessary people to manually do this work at the scale necessary to support the Company's portfolio of applications; (3) manually bolstering resiliency. This alternative was not chosen because it has proven to be error-prone; (4) manually maintaining security posture. This alternative was not chosen because the Company does not have the necessary people to manually do this work at the scale necessary to support the Company's portfolio of applications; (5) manually extending new cloud services. This alternative was not chosen because the services become available faster than the Company can manually deploy them while meeting necessary standards and security postures; (6) and utilizing pre-built tooling without extension or development. This alternative was not chosen because pre-built tooling does not meet the necessary Company standards and security postures. (7) procure automation software and extend the software to meet Company standards. This alternative was selected because the combination provides the most cost-effective method for automation of existing and new services at speed and scale while allowing the services to be deployed in a secure manner that meets Company standards.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/1/2027	2/28/2027	4/30/2027	6/2/2027
	In-Service/Go-Live	**Closeout**	
	9/30/2028	11/13/2028	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	$2.089	$1.619	-	-	-	-	$3.709
O&M	-	-	$0.774	$0.754	-	-	-	-	$1.528
Total Cost of Ownership	-	-	$2.863	$2.373	-	-	-	-	**$5.237**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	-	$2.354	$2.324	-	-	-	-	**$4.678**
Outside Services	-	-	$0.040	-	-	-	-	-	**$0.040**
Business Expense/Overheads	-	-	$0.069	$0.049	-	-	-	-	**$0.119**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	$0.400	-	-	-	-	-	**$0.400**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	-	$2.863	$2.373	-	-	-	-	**$5.237**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	$0.774	$0.754	-	-	-	-	**$1.528**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	$0.774	$0.754	-	-	-	-	**$1.528**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	$2.089	$1.619	-	-	-	-	**$3.709**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	$2.089	$1.619	-	-	-	-	**$3.709**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Digital-Infrastructure Automation

Report Pulled: 4/23/2025 **Item ID: 13437**

EXECUTIVE SUMMARY

Major Application Failure	Medium	Medium	This project will reduce the risk of a major application failure due to a security issue in the infrastructure

OTHER VALUE

Type	Description
Technology Capability	This project will improve solution delivery times for any applications that depend on Company hosted infrastructure (Platform-as-a-Service and Infrastructure-as-a-Service).
Technology Capability	This project will improve the capability of IT to provide infrastructure that hosts applications to the Company quickly and efficiently.
Avoided Costs	This project will optimize the deployment of infrastructure that hosts applications for the company at the time of deployment and automatically as applications are used, thus avoiding excess costs for unused infrastructure.

Electric Geographic Information System (GIS) Design Platfo1 Report Pulled: 4/23/2025 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 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.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
2/24/2025	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	$1.432	$1.110	$2.210	$1.110	$0.277	-	-	-	$6.139
O&M	$0.244	$0.137	$0.137	$0.137	$0.034	$1.140	$1.140	$0.040	$3.009
Total Cost of Ownership	$1.676	$1.247	$2.347	$1.247	$0.312	$1.140	$1.140	$0.040	**$9.148**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.619	$0.852	$0.852	$0.852	$0.213	-	-	-	**$3.389**
Outside Services	$0.500	-	-	-	-	-	-	-	**$0.500**
Business Expense/Overheads	$0.287	$0.394	$0.394	$0.394	$0.099	-	-	-	**$1.568**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.270	-	-	-	-	-	-	-	**$0.270**
Licenses, Permits & Fees	-	-	$1.100	-	-	$1.100	$1.100	-	**$3.300**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.676	$1.247	$2.347	$1.247	$0.312	$1.100	$1.100	-	**$9.028**

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	$0.244	$0.137	$0.137	$0.137	$0.034	$1.140	$1.140	$0.040	**$3.009**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.244	$0.137	$0.137	$0.137	$(2.051)	$(0.945)	$(0.945)	$0.040	**$(3.246)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.432	$1.110	$2.210	$1.110	$0.277	-	-	-	**$6.139**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.432	$1.110	$2.210	$1.110	$0.277	-	-	-	**$6.139**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.479

Risk Tolerance
Electric GIS Design Plat Modern

Electric Geographic Information System (GIS) Design Platfo1 Report Pulled: 4/23/2025 Item ID: 13444

EXECUTIVE SUMMARY

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 Geographic Information System (GIS) Platform Upg

Report Pulled: 4/23/2025 **Item ID: 8852**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , GIS Platform Migration, Geographical Information System (GIS) Platform Upgrade, Electric Geographical Information System (GIS) Platform Upgrade, Electric Geographic Information System (GIS) Platform Upgrade

Description The Electric Geographical Information System (GIS) Platform Upgrade project will upgrade the GIS platform applications, servers, application hosting servers, and databases to the next major versions to remediate the outdated platform technology. The GIS platform supports critical business functionality, including: (1) asset management; (2) electric outage management; (3) field operations mobile mapping solutions; and (4) engineering design.

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

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-TRANS, OPS SUPPORT AND ENG

WORK OBJECTIVES

Problem Statement

The Company's GIS platform has not been upgraded for more than 5 years, and as a result, many of the components that make up the GIS implementation are at risk, including: (1) the current version of GIS (version 10.2.1) will be unsupported starting 6/30/2021, creating a serious cyber security risk as well as a operability risk with the vendor unable to respond to critical issues or provide security patches; (2) the GIS systems that reside on Windows 2008 servers will require extended support starting 1/14/2020, creating an increased cost of premium support limited to a two-year-only extension; (3) the current database technology (Oracle) is obsolete and support ceased in 2015; (4) the GIS platform application hosting platform (Citrix) will be unsupported starting in January 2020. Losing support of the application hosting platform and database technology creates an environment in which security patches cannot be applied to address new vulnerabilities. Although the platform technologies do not go out of support until 2020, the upgrade effort will require a full two years to execute, creating risk with further implementation delay.

Objectives

The project adds value by: (1) remediating GIS, Windows, and Citrix technology obsolescence, creating a stable and sustainable foundational platform for critical business functions; (2) improving platform resilience by remediating current single-point-of-failure areas; (3) sharing technology resources (servers, databases, etc.) across gas and electric platforms to optimize them, yet still ensuring the ability to meet diverse business area functional needs. In addition, the GIS platform remediation work establishes the foundation necessary for the full implementation of the Electric Distribution Asset Management Program.

Scope

Project scope includes: (1) building GIS platform servers, software, and data; (2) expanding GIS platform capabilities; (3) re-architecting current single-point-of-failure areas; (4) designing and developing new architecture; (5) upgrading database technology; (6) re-platforming the application hosting platform (Citrix); and (7) upgrading and reconfiguring applications that use the GIS platform.

Alternatives

The alternatives considered for the project were to: (1) delay implementation, pay a premium for extended Windows support, and incur cyber security and business continuity risk for the application hosting platform and the GIS platform; (2) upgrade the platform to the Utility Network (Utility Network refers to the ArcGIS Utility Network Management extension for scalable modeling across utility assets) as a "big bang" approach without the incremental GIS version upgrade; and (3) perform an iterative platform upgrade to the next GIS version with application platform hosting upgrade, server replacements, and database upgrade, and shift the Utility Network upgrade to a future year. Option 1 was not selected since further project delays will prolong the security and business continuity risk, as well as increase the probability of risk impact due to the level of effort required to complete the project. Option 2 was not selected because the Utility Network upgrade effort is a transformational technology project, requiring extensive data migration in addition to the scope outlined in this project. Furthermore, this alternative will also incur security and business continuity risk given the complexity of a prolonged planning and design effort. Option 3 was selected to implement an iterative upgrade approach as it decreases the overall project complexity while mitigating aging technology platforms. This will enable the future upgrade to the Utility Network in addition to addressing overall platform stability and sustainability in a timelier manner.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/1/2020	6/1/2020	12/1/2020	12/6/2021
	In-Service/Go-Live	**Closeout**	
	12/6/2021	5/23/2022	

FUNDING SUMMARY

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Cap+COR	$0.229	$0.660	$0.607	$0.840	$0.296	-	-	-	$2.632
O&M	$0.147	$0.000	-	-	$0.105	$0.028	$0.628	-	$0.907
Total Cost of Ownership	$0.376	$0.660	$0.607	$0.840	$0.400	$0.028	$0.628	-	**$3.539**

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Labor	$0.312	$0.547	$0.191	$0.288	$0.204	-	-	-	**$1.542**
Outside Services	-	$0.001	$0.266	$0.342	$0.107	-	-	-	**$0.717**
Business Expense/Overheads	$0.063	$0.112	$0.151	$0.210	$0.090	-	-	-	**$0.626**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.376	$0.660	$0.607	$0.840	$0.400	-	-	-	**$2.884**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2020	2021	2022	2023	2024	2025	2026	2027 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.147	$0.000	-	-	$0.105	$0.028	$0.628	-	**$0.907**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.147	$0.000	-	-	$0.105	$0.028	$0.628	-	**$0.907**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.229	$0.660	$0.607	$0.840	$0.296	-	-	-	**$2.632**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.229	$0.660	$0.607	$0.840	$0.296	-	-	-	**$2.632**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Electric Geographic Information System (GIS) Platform Upg Report Pulled: 4/23/2025 Item ID: 8852

EXECUTIVE SUMMARY

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Avoids premium support cost increase for Windows 2008 support, once current support contract ends on 1/14/2020.
Risk Mitigation	The project mitigates security and business continuity risk that would be incurred if the project was not implemented, or the implementation was delayed.

Electric GIS Utility Network Transformation

Report Pulled: 4/23/2025 **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-WORK MANAGEMENT

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	$3.973	$9.432	$5.974	-	-	-	-	-	$19.379
O&M	$1.560	$1.497	$1.951	$0.097	$0.097	$0.097	-	-	$5.299
Total Cost of Ownership	$5.533	$10.929	$7.925	$0.097	$0.097	$0.097	-	-	**$24.678**

	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	$0.371	$1.812	$1.135	-	-	-	-	-	**$3.317**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$2.160	$0.095	$0.070	-	-	-	-	-	**$2.325**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$5.533	$10.929	$7.925	-	-	-	-	-	**$24.387**

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	$3.973	$9.432	$5.974	-	-	-	-	-	**$19.379**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$3.973	$9.432	$5.974	-	-	-	-	-	**$19.379**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Electric GIS Utility Network Transformation

Report Pulled: 4/23/2025 **Item ID: 14022**

EXECUTIVE SUMMARY

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.
Technology Capability	Design and configure OOTB functionality to query, view and extract data from different points in time
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

Electric Infrastructure Attachments

Report Pulled: 4/23/2025 **Item ID: 8777**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Electric Infrastructure Attachments

Description The Company currently collects $5.6M per year as revenue in rent from over 400 third party entities that have attached equipment to Company infrastructure, primarily on distribution poles. There has been exponential growth in attachment requests as Internet providers continue to build out their broadband cable networks. The Electric Infrastructure Attachments (IA) project will implement a technology solution that automates manual processes and supports current and future information storage, processing and reporting needs.

Portfolio Electric Delivery Systems > Electric Grid Integration > Design - Generation > Design - Generation > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-TRANS, OPS SUPPORT AND ENG

WORK OBJECTIVES

Problem Statement The Infrastructure Attachments department currently uses a Microsoft Access database, developed in the early 2000's to support the processes that generate $5.6M in revenue in the form of 3rd party rental of distribution pole space. This obsolete database is used to store an exponentially increasing volume of critical pole attachment information that includes; client usage, contact information and other billing information; active and completed permit application data; and other information necessary to meet external reporting requirements. Due to the limited functionality in the current database, significant manual effort is required for records research, negatively impacting the ability of the Infrastructure Attachments team to support information requests from clients, external entities and departments across the Company. Additionally, benchmarking with other utilities and examination of best practices, indicates that the current solution has significant gaps in capabilities that are standard with newer technologies such as searchable geographically referenced records.

Objectives The benefits of implementing a Commercial Off The Shelf (COTS) pole attachment technology solution include providing the current functionality in a supportable solution as well as; (1) providing new capabilities to further automate manual processes, (2) reducing manual effort through integration with SAP, GIS, the National Joint Utility Notification System (NJUNS), (3) providing a more efficient approach to fulfill information requests; (4) affording a history of pole attachments at a specific location; and (5) reducing waste through improved processes.

Scope The scope of this project includes; (1) evaluate, select and purchase a COTS Infrastructure Attachments solution, (2) design, develop and implement required integrations and, (3) configure, test and implement the end to end solution.

Alternatives Alternatives considered include; (1) Select and implement a fully integrated COTS solution to replace the existing functionality of the Access database, (2) develop an in-house replacement for the Access database and (3) continue to use the current Access database. Alternative two was not chosen because this option would not integrate with Corporate systems, exasperating ongoing issues with data discrepancies and client dissatisfaction making it an inferior solution. Alternative three is unacceptable due to the stated business risks. The first alternative was selected because it will provide for an integrated and supported solution.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
4/15/2021	8/30/2021	11/30/2021	3/30/2022
	In-Service/Go-Live	**Closeout**	
	4/30/2022	5/30/2022	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$0.314	$0.304	$0.436	$0.273	-	-	-	-	$1.327
O&M	$0.051	$0.048	$0.021	$0.043	-	-	-	-	$0.164
Total Cost of Ownership	$0.366	$0.352	$0.457	$0.317	-	-	-	-	**$1.491**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.073	$0.069	$0.127	$0.032	-	-	-	-	**$0.300**
Outside Services	$0.289	$0.234	$0.243	$(0.114)	-	-	-	-	**$0.653**
Business Expense/Overheads	$0.004	$0.049	$0.087	$0.054	-	-	-	-	**$0.194**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	$0.345	-	-	-	-	**$0.345**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.366	$0.352	$0.457	$0.317	-	-	-	-	**$1.491**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.051	$0.048	$0.021	$0.043	-	-	-	-	**$0.164**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.051	$0.048	$0.021	$0.043	-	-	-	-	**$0.164**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.314	$0.304	$0.436	$0.273	-	-	-	-	**$1.327**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.314	$0.304	$0.436	$0.273	-	-	-	-	**$1.327**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Material Weakness in Business Controls	High	Medium	Maintaining accurate pole attachment records and maps meets compliance requirements and mitigates risk.
Electric LVD Lines	Medium	Medium	The solutions ensures the accuracy of 3rd party attachment records that are used by Low Voltage Distribution Design Engineering.

OTHER VALUE

Type	Description
Risk Mitigation	The solution ensures that regulatory requirements for 3rd parties are met, mitigating the risk of of non-compliance.

Electric ProjectWise

Report Pulled: 4/23/2025 **Item ID: 8857**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Electric Projectwise

Description ProjectWise is a suite of project collaboration software for engineering projects currently in use at the Company by Transmission Pipeline, Storage, System Integrity, Compression, Metering & Regulation, Distributed Energy Resources, and Generation Engineering teams. It is capable of bundling, managing, and handling the versions of records and documents related to designs, proposals, contract resources, and record-keeping. The Electric ProjectWise project will expand the implementation of the software to Electric High Voltage Distribution Planning and Design, Low Voltage Distribution Planning and Design, and Sub Metro Engineering. The software can also be used to facilitate the management of change process across the Electric Grid Integration. Need approval for all work items to complete project: Work ID 8857/10681 Projectwise; 12097/12094 Fund PW Change Champion; 12092/12093 Fund additional PW License Costs (2022 only)

Portfolio Electric Delivery Systems > Electric Distribution > Planning - LVD System > Planning - LVD System > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-TRANS, OPS SUPPORT AND ENG

WORK OBJECTIVES

Problem Statement

As part of the Company's shift towards renewable assets along with modernizing the grid, the Company is deploying renewable assets that tie into both LVD & HVD distribution systems along with grid modernization devices across the distribution system. There are many process and technology inter-dependencies related to managing our engineering records within Electric Grid Integration (EGI). Across EGI there are several processes and systems utilized to manage the records related to our assets. Some of the processes are not documented or the documentation is not up to date. This creates limited standardization related to what records are kept for each asset type, and what documentation is turned over to Operations as part of the closeout process. Long term this impacts the operability of these assets and limits how well the Company can maintain these assets without complete engineering records. Key problems manifesting as a result include no single source of truth for our engineering records for assets that blur the lines of HVD/LVD/Generation, lack of standardized process for records management, limited integration with EPM's Project Management Information System, and impacts Customer Energy Management (CEM) who will utilize ProjectWise for Gas Assets in the near future with integration with SAP. Several key problem themes have been identified by internal stakeholders around the current state of EGI's engineering records management at the Company including: (1) limited agility/flexibility of the team as each asset type has its own processes and tools; (2) no uniform document repository to manage records for the complete lifecycle for Electric Grid Integration (3) lack of adherence or no standardized processes; and (4) limited ability to integrate with internal and external stakeholders (Enterprise Project Management, Electric Operations, CEM, A/E firms, and International Transmission Company (ITC) are examples).

Objectives

Completion of this project will provide value to the Company by: (1) providing a centralized repository for document retention, archival and version tracking, resulting in records that are traceable and retrievable; (2) improving comprehensive documentation to be inclusive of all design review changes from key technical Subject Matter Expert (SME) groups; (3) enabling end to end workflow tracking and approval sign-off from initial design and engineering through final sign-off; (4) improving consistency with technical records across project and asset lifecycles; (5) decreasing risk of not having complete and accurate records that are readily accessible and easily searchable; (6) enabling tracking of temporary and permanent electric distribution system configuration changes in a centralized repository; (7) enhancing spatial relationships within drawings and documents such that all documents pertinent to a geographic location can be quickly accessed and maintained; (8) creating a universal system of record for all native construction prints; (9) enabling tracking of project as-built and final project record completion. The project provides additional value by implementing management of change tool with capabilities that can be leveraged by other departments throughout the Company.

Scope

The scope of this project encompasses the implementing ProjectWise software modules for use by Customer Energy Management (CEM), LVD Planning and Design, Underground Metro Planning and Design, HVD Planning and Design, and Electric Operations Departments. The project will: (1) configure the software modules within the application, and (2) design and develop integrations with other Company systems. Prior to the project start, the team will work collaboratively with the Electric Grid Integration organization to develop an engineering records management rollout plan that is aligned with business processes.

Alternatives

Alternatives considered include: (1) Continue current engineering records processes. This alternative was not selected because it significantly increases the cost and effort over time, resulting in waste for Engineering and Operations as the Company deploys its long-term capital investments into grid modernization along with a shift from fossil generation plants towards distributed energy resources. This alternative also limits the integration with the planned upgrade of the Geographic Information System (GIS) along with the planned rollout of the Distribution Asset Management processes and program. (2) Develop an engineering records management tool and processes for LVD only to support the rollout of ProjectWise to CEM. This alternative was not selected because it limits change to just LVD and does not support integration with Distributed Energy Resources assets across LVD & HVD. (3) Develop an engineering records management rollout plan and supporting business case that aligns processes and tools initiatives into one program, taking a phased approach to develop and implement the strategy. This alternative was selected because it starts by identifying and addressing key gaps that have been identified, which includes closing the gap of the lack of a standardized process for engineers and designers to create and managed engineering records. Furthermore, this alternative will provide a uniform process and platform for both Engineering and Operations to gain access to our records, and additionally addresses the technology and process inter-dependency gaps that are presently planned in silos with design tools, GIS, and Asset Management. Finally, this alternative optimizes engineering records management across both generation and Electric Distribution and mirror planned work in the gas business units.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/1/2022	3/1/2022	9/1/2022	9/1/2023
	In-Service/Go-Live	**Closeout**	
	10/1/2023	11/1/2023	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	$0.001	$0.035	$0.009	-	-	-	-	-	$0.044
O&M	$0.124	$0.067	$0.007	$0.051	$0.062	$0.067	$0.067	-	$0.445
Total Cost of Ownership	$0.125	$0.102	$0.016	$0.051	$0.062	$0.067	$0.067	-	**$0.490**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	$0.019	$0.035	$0.014	-	-	-	-	-	**$0.068**
Outside Services	$0.099	$0.066	$0.000	-	-	-	-	-	**$0.165**
Business Expense/Overheads	$0.006	$0.001	$0.002	-	-	-	-	-	**$0.009**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.125	$0.102	$0.016	-	-	-	-	-	**$0.243**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

Electric ProjectWise

Report Pulled: 4/23/2025 **Item ID: 8857**

EXECUTIVE SUMMARY

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.124	$0.067	$0.007	$0.051	$0.062	$0.067	$0.067	-	**$0.445**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.124	$0.067	$0.007	$0.051	$0.062	$0.067	$0.067	-	**$0.445**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.001	$0.035	$0.009	-	-	-	-	-	**$0.044**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.001	$0.035	$0.009	-	-	-	-	-	**$0.044**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Electric LVD Lines	Low	Low	•Mitigates the risk of losing or not finding project documents because the new solution has the ability to maintain spatial relationships within drawings and documents such that all documents pertinent to a geographical location can be quickly located and maintained□ •Mitigate the risk associated with incorrect, incomplete or missing design changes by establishing document retention, archival and version tracking resulting in records that are traceable and verifiable.□ •Mitigate the risk with having different versions of engineering designs by providing a single source of truth for Electric Distribution technical records.□ •Increased public and employee safety and regulatory compliance with complete and accurate records that are readily available through the new solution.

OTHER VALUE

Type	Description
Technology Capability	•Will enable Integration with GIS and future integration with Electric Distribution Asset Management program technologies. □ •Will enable record linkages across electric distribution for Distributed Energy Resources□ •Will provide capabilities enabling direct communications with with International Transmission Company (ITC) for shared engineering records□ •Will provide capabilities enabling direct communications with external consultants and contractors through the use of ProjectWise's Cloud Services features.
Intangibles	Reduces the time and improves quality of design through; (1) provides the ability to track documentation related to project designs, proposals, contract resources and record-keeping; (2) provides the ability to render drawings that are composed of several files, as is the case with many CAD drawings such as those produced in Microstation and AutoCAD software, as one document; (3) maintains spatial relationships within drawings and documents such that all documents pertinent to a geographical location can be quickly located and maintained; (4) integrates with Microstation, Microsoft Office, AutoCAD, SharePoint, SAP and potentially other systems; (5) provides better search ability through rich metadata; (6) establishes document retention, archival and version tracking resulting in records that are traceable and retrievable, integration with SAP, Other apps on Loadspring so do not count retirement in this BC. liminate Loadspring (IT inventory in progress), P6, Publisher, CMV14, (where is this funded?)Risk mitigation, information governance

Energy Assistance Enhancements and Maintenance Annual U Report Pulled: 4/23/2025 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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.208	$0.315	$0.312	$0.312	$0.312	$0.312	$0.312	-	$2.081
Total Cost of Ownership	$0.208	$0.315	$0.312	$0.312	$0.312	$0.312	$0.312	-	**$2.081**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.102	$0.175	$0.266	$0.266	$0.266	$0.266	$0.266	-	**$1.609**
Outside Services	$0.094	$0.140	$0.025	$0.025	$0.025	$0.025	$0.025	-	**$0.358**
Business Expense/Overheads	$0.012	-	$0.020	$0.020	$0.020	$0.020	$0.020	-	**$0.114**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.208	$0.315	$0.312	$0.312	$0.312	$0.312	$0.312	-	**$2.081**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.208	$0.315	$0.312	$0.312	$0.312	$0.312	$0.312	-	**$2.081**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.208	$0.315	$0.312	$0.312	$0.312	$0.312	$0.312	-	**$2.081**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Energy Assistance Enhancements and Maintenance Annual U

Report Pulled: 4/23/2025 **Item ID: 6683**

EXECUTIVE SUMMARY

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: 4/23/2025 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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.799	$0.564	-	-	-	-	-	-	$1.363
O&M	$0.076	$0.042	-	-	-	-	-	-	$0.117
Total Cost of Ownership	$0.875	$0.605	-	-	-	-	-	-	**$1.480**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.309	$0.226	-	-	-	-	-	-	**$0.535**
Outside Services	$0.332	$0.315	-	-	-	-	-	-	**$0.646**
Business Expense/Overheads	$0.195	$0.065	-	-	-	-	-	-	**$0.259**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.027	-	-	-	-	-	-	-	**$0.027**
Licenses, Permits & Fees	$0.013	-	-	-	-	-	-	-	**$0.013**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.875	$0.605	-	-	-	-	-	-	**$1.480**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.076	$0.042	-	-	-	-	-	-	**$0.117**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.076	$0.042	-	-	-	-	-	-	**$0.117**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.799	$0.564	-	-	-	-	-	-	**$1.363**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.799	$0.564	-	-	-	-	-	-	**$1.363**
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: 4/23/2025

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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.145	$0.140	-	-	-	-	-	-	$0.285
Total Cost of Ownership	$0.145	$0.140	-	-	-	-	-	-	**$0.285**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.046	$0.053	-	-	-	-	-	-	**$0.098**
Outside Services	$0.093	$0.087	-	-	-	-	-	-	**$0.181**
Business Expense/Overheads	$0.006	-	-	-	-	-	-	-	**$0.006**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.145	$0.140	-	-	-	-	-	-	**$0.285**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.145	$0.140	-	-	-	-	-	-	**$0.285**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.145	$0.140	-	-	-	-	-	-	**$0.285**
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

Enhancements-CX&O-O&M *EXECUTIVE SUMMARY*	**Report Pulled: 4/23/2025**	**Item ID: 11375**
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-IT-Capital

Report Pulled: 4/23/2025 **Item ID: 11332**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias Enhancements - TSM, Application Currency and Enhancements - Infrastructure Applications and Operations - O&M, Enhancements - Infrastructure Applications and Operations - Capital, Enhancements - IAO - Capital, Enhancements - IT - Capital, Enhancements-IT-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 > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ENTERPRISE PRODUCTS AND SE

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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.168	$0.057	-	-	-	-	-	-	$0.225
O&M	$0.000	$0.000	-	-	-	-	-	-	$0.000
Total Cost of Ownership	$0.168	$0.057	-	-	-	-	-	-	**$0.225**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.045	$0.014	-	-	-	-	-	-	**$0.059**
Outside Services	$0.057	$0.000	-	-	-	-	-	-	**$0.057**
Business Expense/Overheads	$0.064	$0.042	-	-	-	-	-	-	**$0.106**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	$0.000	-	-	-	-	-	-	**$0.000**
Licenses, Permits & Fees	$0.002	$0.000	-	-	-	-	-	-	**$0.002**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.168	$0.057	-	-	-	-	-	-	**$0.225**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.000	$0.000	-	-	-	-	-	-	**$0.000**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.000	$0.000	-	-	-	-	-	-	**$0.000**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.168	$0.057	-	-	-	-	-	-	**$0.225**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.168	$0.057	-	-	-	-	-	-	**$0.225**
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-IT-O&M

Report Pulled: 4/23/2025 **Item ID: 11334**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias Enhancements - TSM, Application Currency and Enhancements - Infrastructure Applications and Operations - O&M, Enhancements - Infrastructure Applications and Operations - Capital, Enhancements - IAO - Capital, Enhancements - IAO - O&M, Enhancements - IT - O&M, Enhancements-IT-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 > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ENTERPRISE PRODUCTS AND SE

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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.073	$0.004	-	-	-	-	-	-	$0.076
Total Cost of Ownership	$0.073	$0.004	-	-	-	-	-	-	**$0.076**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.009	-	-	-	-	-	-	-	**$0.009**
Outside Services	$0.056	$0.003	-	-	-	-	-	-	**$0.060**
Business Expense/Overheads	$0.003	$0.000	-	-	-	-	-	-	**$0.003**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.004	-	-	-	-	-	-	-	**$0.004**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.073	$0.004	-	-	-	-	-	-	**$0.076**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.073	$0.004	-	-	-	-	-	-	**$0.076**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.073	$0.004	-	-	-	-	-	-	**$0.076**
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: 4/23/2025 **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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.599	$0.000	-	-	-	-	-	-	$0.599
O&M	$0.028	$0.003	-	-	-	-	-	-	$0.031
Total Cost of Ownership	$0.626	$0.004	-	-	-	-	-	-	**$0.630**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.157	-	-	-	-	-	-	-	**$0.157**
Outside Services	$0.258	$0.003	-	-	-	-	-	-	**$0.262**
Business Expense/Overheads	$0.203	$0.000	-	-	-	-	-	-	**$0.203**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.009	-	-	-	-	-	-	-	**$0.009**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.626	$0.004	-	-	-	-	-	-	**$0.630**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.028	$0.003	-	-	-	-	-	-	**$0.031**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.028	$0.003	-	-	-	-	-	-	**$0.031**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.599	$0.000	-	-	-	-	-	-	**$0.599**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.599	$0.000	-	-	-	-	-	-	**$0.599**
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: 4/23/2025 **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 M(

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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.270	$0.412	$1.599	$0.816	$0.816	$0.816	$0.816	-	$6.546
O&M	$0.267	$0.037	$0.100	$0.153	$0.153	$0.153	$0.153	-	$1.014
Total Cost of Ownership	$1.537	$0.449	$1.699	$0.969	$0.969	$0.969	$0.969	-	**$7.560**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.617	$0.033	$0.518	$0.245	$0.245	$0.245	$0.245	-	**$2.148**
Outside Services	$0.151	$(0.103)	$0.274	$0.173	$0.173	$0.173	$0.173	-	**$1.014**
Business Expense/Overheads	$0.131	$0.008	$0.602	$0.525	$0.525	$0.525	$0.525	-	**$2.840**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.026	$0.008	$0.024	$0.026	$0.026	$0.026	$0.026	-	**$0.164**
Licenses, Permits & Fees	$0.612	$0.502	$0.281	-	-	-	-	-	**$1.394**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$1.537	$0.449	$1.699	$0.969	$0.969	$0.969	$0.969	-	**$7.560**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.267	$0.037	$0.100	$0.153	$0.153	$0.153	$0.153	-	**$1.014**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.267	$0.037	$0.100	$0.153	$0.153	$0.153	$0.153	-	**$1.014**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$1.270	$0.412	$1.599	$0.816	$0.816	$0.816	$0.816	-	**$6.546**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$1.270	$0.412	$1.599	$0.816	$0.816	$0.816	$0.816	-	**$6.546**
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: 4/23/2025 **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 M(

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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.540	$0.374	$0.490	$0.490	$0.459	$0.490	-	-	$2.841
Total Cost of Ownership	$0.540	$0.374	$0.490	$0.490	$0.459	$0.490	-	-	**$2.841**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.324	$0.333	$0.347	$0.347	$0.347	$0.347	-	-	**$2.045**
Outside Services	$0.123	$0.007	$0.015	$0.015	$0.015	$0.015	-	-	**$0.191**
Business Expense/Overheads	$(0.000)	$0.022	$0.110	$0.110	$0.079	$0.110	-	-	**$0.430**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.054	-	$0.018	$0.018	$0.018	$0.018	-	-	**$0.125**
Licenses, Permits & Fees	$0.040	$0.012	-	-	-	-	-	-	**$0.051**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.540	$0.374	$0.490	$0.490	$0.459	$0.490	-	-	**$2.841**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.540	$0.374	$0.490	$0.490	$0.459	$0.490	-	-	**$2.841**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.540	$0.374	$0.490	$0.490	$0.459	$0.490	-	-	**$2.841**
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-TEOS-Capital

Report Pulled: 4/23/2025 **Item ID: 11328**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Application Currency and Enhancements - TEOS - Capital, Enhancements - TEOS - Capital, Enhancements-TEOS-Capital

Description The TEOS 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-TRANS, OPS SUPPORT AND ENG

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 TEOS 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 TEOS.

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 Gas Engineering, Customer Energy Management, Electric Grid Integration, and Fleet .

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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.541	$0.017	-	-	-	-	-	-	$0.558
O&M	$0.042	$0.002	-	-	-	-	-	-	$0.043
Total Cost of Ownership	$0.583	$0.019	-	-	-	-	-	-	**$0.602**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.120	$0.009	-	-	-	-	-	-	**$0.129**
Outside Services	$0.278	$0.000	-	-	-	-	-	-	**$0.279**
Business Expense/Overheads	$0.184	$0.009	-	-	-	-	-	-	**$0.194**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.583	$0.019	-	-	-	-	-	-	**$0.602**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.042	$0.002	-	-	-	-	-	-	**$0.043**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.042	$0.002	-	-	-	-	-	-	**$0.043**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.541	$0.017	-	-	-	-	-	-	**$0.558**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.541	$0.017	-	-	-	-	-	-	**$0.558**
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.

Enterprise Print - Scan Suite

Report Pulled: 4/23/2025 **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	-	-	-	-	-	-	-	$0.627
O&M	$0.085	$0.004	$0.004	$0.004	$0.004	$0.004	-	-	$0.104
Total Cost of Ownership	$0.712	$0.004	$0.004	$0.004	$0.004	$0.004	-	-	**$0.731**

	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	-	-	-	-	-	-	-	**$0.008**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.012	-	-	-	-	-	-	-	**$0.012**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.712	-	-	-	-	-	-	-	**$0.712**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.085	$0.004	$0.004	$0.004	$0.004	$0.004	-	-	**$0.104**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.085	$0.004	$0.004	$0.004	$0.004	$0.004	-	-	**$0.104**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.627	-	-	-	-	-	-	-	**$0.627**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.627	-	-	-	-	-	-	-	**$0.627**
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: 4/23/2025 **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 simplify processes pertaining to Enterprise Risk Management, improve efficiency, provide risk identification and repository tools, and provide real-time risk information.

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) works with Risk Owners (RO) on an annual basis to identify new risks, update existing risks, quantify impacts and likelihoods of these risks, document mitigation plans, identify trends, and formulate risk tolerance metrics. This work is accomplished through an iterative back-and-forth process between ERT and ROs to gain alignment on content. This effort culminates in multiple Risk Map PowerPoint, Microsoft Word and email documents organized by area of risk. These risk maps are then presented to senior management and to the Board of Directors (BoD) on an annual basis. The intensive, time-consuming manual Enterprise Risk Management (ERM) process creates risks of human error that can over or under quantify risks, introduce data anomalies, and create version tracking issues. The existing process results in substantial inefficient use of time by risk analysts and risk owners throughout the Company, limits the breadth of analysis that can be provided, and limits the overall ability of the Company to timely identify, analyze, and communicate risks to our senior leaders, thereby causing potential delays in responding to emerging risks. Because of the lengthy manual process, it is only performed once a year, but must be performed more frequently to proactively manage enterprise risk. Utility industry peers leverage 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 interested parties including the risk team, risk owners, senior management, and the Board of Directors (BoD) supporting proactive risk management; (2) creating a centralized repository for risk identification, management, and mitigation plans; (3) eliminating waste by simplifying processes; and (4) improving efficiency of the risk owners and analysts.

Scope

The scope of the project includes: (1) create risk analysis templates and tools for automated reporting; (2) configure automated workflow to perform risk updates; (3) configure dynamic templates that prompt the risk owners based on prior selections; (4) organize risk assessments through an online and searchable data capture (repository); (5) create new reports and executive dashboards; (6) data conversion; and (7) set record retention rules.

Alternatives

Alternatives considered include: (1) Continue use of the current manual processes which result in waste, lack of quality results, and annual review of risks. (2) Build a custom internal enterprise risk solution. This option was not selected as it will not result in an enterprise risk program that leverages best practices that exist in software provided by the leaders in risk management software (3) Implement a software solution from a leading enterprise risk solution vendor. While this would introduce new license and ongoing support costs, it is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation and insights via the reporting of risk information through management dashboards. In addition, 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
1/1/2026	4/1/2026	6/1/2026	11/1/2026
	In-Service/Go-Live	**Closeout**	
	12/1/2026	1/1/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.080	$0.069	$0.069	$0.069	-	-	-	-	$0.285
Total Cost of Ownership	$0.080	$0.069	$0.069	$0.069	-	-	-	-	**$0.285**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.025	$0.021	$0.021	$0.021	-	-	-	-	**$0.088**
Outside Services	$0.053	$0.046	$0.046	$0.046	-	-	-	-	**$0.191**
Business Expense/Overheads	$0.002	$0.002	$0.002	$0.002	-	-	-	-	**$0.007**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.080	$0.069	$0.069	$0.069	-	-	-	-	**$0.285**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.080	$0.069	$0.069	$0.069	-	-	-	-	**$0.285**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.080	$0.069	$0.069	$0.069	-	-	-	-	**$0.285**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Enterprise Risk Management | **Report Pulled: 4/23/2025** | **Item ID: 10481**

EXECUTIVE SUMMARY

OTHER VALUE

Type	Description
Avoided Costs	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 free up time for more value-added activities such as ad hoc analysis, more frequent risk updates to management, emerging risk evaluation, and risk mitigation planning. Business areas can save up to 127 hours annually though efficiencies in: (1) Risk template updates (61 hours saved); (2) Emails/phone calls with Risk Group (33 hours saved); (3) Alignment with Risk and their own Management chains (32 hours saved). These efficiencies would allow these risk owners to focus on the job of running the business and implementing risk reduction mitigation as opposed to administratively filling out risk forms.
Risk Mitigation	Implementing a centralized solution will mitigate risk by better managing risks. One third of the 150 risk tolerance metrics are currently red.
Risk Mitigation	This project would track more than 200 corporate risk tolerances from the Impact group within the Business Planning System (BPS). The Corporate Risk group tracks all of these risks and the number of risks is expected to grow over time.

Enterprise Service Bus Application 2024-2025 Upgrade

Report Pulled: 4/23/2025 **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 & SER

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	$0.013	$0.773	-	-	-	-	-	-	$0.785
Total Cost of Ownership	$0.013	$0.773	-	-	-	-	-	-	**$0.785**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.011	$0.722	-	-	-	-	-	-	**$0.733**
Outside Services	$0.002	-	-	-	-	-	-	-	**$0.002**
Business Expense/Overheads	-	$0.051	-	-	-	-	-	-	**$0.051**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.013	$0.773	-	-	-	-	-	-	**$0.785**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.013	$0.773	-	-	-	-	-	-	**$0.785**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.013	$0.773	-	-	-	-	-	-	**$0.785**
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, IWP, 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.

Field Contractor Work Management Technology Enablemen | Report Pulled: 4/23/2025 | 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	-	-	-	-	$1.685
O&M	$0.243	$0.218	$0.023	$0.352	$0.508	$0.508	$0.508	$0.508	$2.867
Total Cost of Ownership	$0.243	$0.245	$0.367	$1.665	$0.508	$0.508	$0.508	$0.508	**$4.552**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.229	$0.082	$0.098	$0.487	-	-	-	-	**$0.896**
Outside Services	-	$0.144	$0.212	$0.780	-	-	-	-	**$1.136**
Business Expense/Overheads	$0.014	$0.019	$0.054	$0.126	-	-	-	-	**$0.212**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.003	$0.256	-	-	-	-	**$0.259**
Licenses, Permits & Fees	-	-	-	$0.017	-	-	-	-	**$0.017**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.243	$0.245	$0.367	$1.665	-	-	-	-	**$2.520**

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	$0.508	$0.508	$0.508	$0.508	**$2.867**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.243	$0.218	$(0.120)	$0.208	$0.364	$0.364	$0.364	$0.508	**$2.148**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.027	$0.343	$1.314	-	-	-	-	**$1.685**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.027	$0.343	$1.314	-	-	-	-	**$1.685**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.855

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Field Contractor Work Management Technology Enablemen **Report Pulled: 4/23/2025** **Item ID: 6740**

EXECUTIVE SUMMARY

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: 4/23/2025 **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	-	-	-	$3.843
O&M	$0.006	$0.016	$0.001	$0.040	$0.016	-	-	-	$0.077
Total Cost of Ownership	$0.006	$0.678	$1.560	$0.915	$0.763	-	-	-	**$3.921**

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Labor	$0.005	$0.221	$0.299	$0.312	$0.229	-	-	-	**$1.066**
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	-	-	-	**$0.619**
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	-	-	-	**$3.921**

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	-	-	-	**$0.077**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.006	$0.016	$(0.063)	$(0.024)	$(0.048)	$(0.064)	$(0.064)	-	**$(0.241)**
Cap+COR	Reduction	-	-	$(0.149)	$(0.149)	$(0.149)	$(0.149)	$(0.149)	-	**$(0.743)**
	Initial	-	$0.662	$1.559	$0.875	$0.747	-	-	-	**$3.843**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.662	$1.410	$0.727	$0.599	$(0.149)	$(0.149)	-	**$3.100**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.767

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	Consumers Energy employees are experiencing decline in application performance due to age, which produces the risk of application failure.

Field Mapping and Graphics

EXECUTIVE SUMMARY

Report Pulled: 4/23/2025 **Item ID: 8771**

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.

Forestry System Conversion And Update

Report Pulled: 4/23/2025 **Item ID: 12839**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Electric Forestry System, Forestry System Conversion And Update

Description This project will modernize the Forestry systems to take advantage of modern technology that will enable a reduction in human struggle by providing improved work management solution.

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

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

WORK OBJECTIVES

Problem Statement

Forestry is currently utilizing MS Access and Excel to support their system-wide program workflow management, contractor invoicing, and data storage, this has resulted in highly specialized daily manual processes, limitations in automation opportunities, data inconsistencies, and lagged productivity reporting causing waste. This system is not supported by IT and is vulnerable to security risks and ancestral knowledge loss. In addition, the current system does not tie in effective work management processes or Vegetation Management analytics. In its current condition, not only is this product lacking durable support, it is also extremely difficult to avail itself of modern Machine Learning techniques, resulting in a system that is not flexible to the ever-changing business needs or advancement in technology to aid the business. Lastly, the target condition would include modern methods for authentication for all contractor groups.

Objectives

Modernize the Forestry work planning, execution, and payment processes. Centralize and provide an updated user interface for all Forestry work planning. Provide workflows for internal Foresters and external vendors. Improve invoicing processes and provide workflow to expedite and report financial metrics while adhering to compliance . All work auditing processes will be improved along with approvals and exception reporting for CE foresters. Centralized Forestry work plan, status and billing data that has a single source of truth to aid in determining Forestry strategic objectives and deliver real-time reporting capabilities. Lastly, the solution would enable the standardization for LCP location definitions and provide centralized vendor access and provide analytics capabilities to assist in prioritizing work.

Scope

The project would replace the current system with a solution that would support an updated database, improved work management processes, ability leverage in place enterprise Asset Management tools while providing fiscal intelligence on spend, pay back, repeat visits, maintenance plans. Additionally, leverage real-time data Analytics for vegetation management and work priorities while improving work assignment capabilities and storm support. The solution would have the capability to Automatically route approvals of vendor invoices. Provide for external contractors to administer work assignments and return invoices through a secured log-in.

Alternatives

Several alternatives have been considered they include the following: 1) Leaving the homegrown Access database in place and working to improve it. This option was not chosen because of the significant risk associated with an older application not supported by IT. 2) The next option is the option pursue an entirely COTS (Custom Off-the Shelf) solution by an industry leader in the Forestry space. The options are numerous and the technology in this discipline has evolved, but does not provide long-term flexibility. 3) Implementing an IT supported hybrid solution of an off-the-shelf work management component with custom built predictive analytics capabilities. This is the preferred option, and will provide a more targeted fit for the forestry organizations requirements.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
9/1/2025	11/3/2025	3/2/2026	8/3/2026
	In-Service/Go-Live	**Closeout**	
	8/4/2026	9/4/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$2.503	-	-	-	-	-	-	-	$2.503
O&M	$0.214	$0.125	$0.125	$0.125	$0.125	-	-	-	$0.714
Total Cost of Ownership	$2.717	$0.125	$0.125	$0.125	$0.125	-	-	-	**$3.217**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$1.075	-	-	-	-	-	-	-	**$1.075**
Outside Services	$0.100	-	-	-	-	-	-	-	**$0.100**
Business Expense/Overheads	$0.592	-	-	-	-	-	-	-	**$0.592**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.950	-	-	-	-	-	-	-	**$0.950**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$2.717	-	-	-	-	-	-	-	**$2.717**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.214	$0.125	$0.125	$0.125	$0.125	-	-	-	**$0.714**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.214	$0.125	$0.125	$0.125	$0.125	-	-	-	**$0.714**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.503	-	-	-	-	-	-	-	**$2.503**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.503	-	-	-	-	-	-	-	**$2.503**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Forestry System Conversion And Update

EXECUTIVE SUMMARY

Report Pulled: 4/23/2025 **Item ID: 12839**

OTHER VALUE

Type	Description
Risk Mitigation	Automated regulatory reporting enablement: MPSC Reliability Reporting from Storm Order U-21122. Noncompliance has significant fines. Statute is $150 per day per incident. Reputational damage and potential disallowances.
Capacity	Enablement of predictive LCP clearing sub-program (MPSC requirement) and intra-circuit LCP prioritization. The top 30 miles of worst performing LCPs account for 4.1 minutes of tree-related SAIDI per year. Assume 40% reduction in incidents over a year period: 4.1 min * 0.40 = 1.64 min. SAIDI improvement of 1.64 min per year.
Avoided Costs	Improve contractor productivity. Unit costS on a weekly, quarterly, and circuit basis is dependent on work completion data, which currently has a 1-2 week lag-time. Having real-time data availability will enable timely and agile business decision-making. Program spend: ~$100M per year 5% * 100M = $5M.
Avoided Costs	Integrating bundling strategy for circuits with overlap on the same poles - LVD with LVD underbuilds by enabling LCP-level data granularity. 600 miles of LVD circuits overlap with at least 1 other LVD circuit. 2024 Cost per Mile Projection = $15,586. Overlapping Span Miles = 600 miles Total Circuit Miles = 1,200 miles. Average overlap span is partially grown back by the time a crew returns in the current-day process, ~20% cheaper than the average line mile. Savings of 1.07M per year.
Avoided Costs	Non-MED Service Restoration cost avoidance from the prevention of more tree-related incidents (saved truck rolls). 2022 cost per outage incident = $3,578 Tree-caused CAIDI = 17.5% larger than all outage incidents 2022 estimated cost per tree-caused outage incident = (117.5% * $3,578) = $4,204. Combined savings of initiative = (1.64 min + 0.5 min + 0.4 min) = 2.54 min. 2.4 minutes of SAIDI = ~ 265 outage incidents on average (source: Forestry WISE model). (2.54 min / 2.4 min) * 265 = 280 incidents $4,204 * 280 incidents = $1,17M per year in savings.

Forward Web Proxy Services

Report Pulled: 4/23/2025 **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 current web proxy service platform with a new platform. A web proxy service is a type of proxy server that sits between a client and the internet. 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 & STAN

WORK OBJECTIVES

Problem Statement The Company currently leverages an existing vendor platform for web proxy services that has been in existence since 2021. Since the implementation of the platform, it has caused ongoing operational issues related to web filtering and connectivity. When there is a degradation of service, Company employees and contractors are unable to access internet or cloud-based resources. As the Company continues its cloud and SAAS journey, it is imperative to provide consistent access and communication, while still protecting the Company from cyber threats.

Objectives This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilizing 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; and (4) providing Zero Trust by continuously verifying every connection request.

Scope The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; and (3) potentially changing SAAS cloud vendors

Alternatives 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. This alternative was not chosen due to the consistent 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, and SharePoint Online; (2) route all internet traffic through the Company's corporate data center. This alternative was not chosen because the capabilities of firewalls are not as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) replace current system with modern vendor platform for web proxy services. The option that was chosen is to replace the current solution with a new system. This option was chosen because it offers additional features such as browser isolation (the ability to contain web pages so that the web page cannot 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 capabilities.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/15/2026	2/15/2026	4/15/2026	6/1/2026
	In-Service/Go-Live	**Closeout**	
	11/15/2026	1/30/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$4.482	-	-	-	-	-	-	-	$4.482
O&M	$0.484	$0.139	$0.130	$0.130	-	-	-	-	$0.883
Total Cost of Ownership	$4.965	$0.139	$0.130	$0.130	-	-	-	-	**$5.364**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.059	$0.139	$0.130	$0.130	-	-	-	-	**$0.457**
Outside Services	$0.192	-	-	-	-	-	-	-	**$0.192**
Business Expense/Overheads	$0.507	$0.001	-	-	-	-	-	-	**$0.507**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	$4.208	-	-	-	-	-	-	-	**$4.208**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$4.965	$0.139	$0.130	$0.130	-	-	-	-	**$5.364**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.484	$0.139	$0.130	$0.130	-	-	-	-	**$0.883**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.484	$0.139	$0.130	$0.130	-	-	-	-	**$0.883**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$4.482	-	-	-	-	-	-	-	**$4.482**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$4.482	-	-	-	-	-	-	-	**$4.482**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Forward Web Proxy Services

Report Pulled: 4/23/2025 **Item ID: 13974**

EXECUTIVE SUMMARY

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: 4/23/2025 **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 the current process and information. (4) The improved maintenance program will reduce equipment downtime resulting in an increase to Megawatt hours produced.

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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	$0.073	$1.151	-	-	-	-	-	$1.225
O&M	-	$0.004	$0.065	$0.004	$0.072	$0.163	$0.163	-	$0.472
Total Cost of Ownership	-	$0.078	$1.217	$0.004	$0.072	$0.163	$0.163	-	**$1.697**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	$0.039	$0.611	-	-	-	-	-	**$0.650**
Outside Services	-	$0.029	$0.146	-	-	-	-	-	**$0.175**
Business Expense/Overheads	-	$0.000	$0.191	-	-	-	-	-	**$0.191**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.009	$0.269	-	-	-	-	-	**$0.279**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.078	$1.217	-	-	-	-	-	**$1.295**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.004	$0.065	$0.004	$0.072	$0.163	$0.163	-	**$0.472**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.004	$0.065	$0.004	$0.072	$0.163	$0.163	-	**$0.472**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.073	$1.151	-	-	-	-	-	**$1.225**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.073	$1.151	-	-	-	-	-	**$1.225**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Generation Operations Digital Work Management

EXECUTIVE SUMMARY

Report Pulled: 4/23/2025 **Item ID: 6766**

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: 4/23/2025 **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	$0.138	$0.596	$1.137	$1.174	$0.993	$0.031	-	-	$4.068
Total Cost of Ownership	$0.138	$0.596	$1.137	$1.174	$0.993	$0.031	-	-	**$4.068**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.001	$(0.035)	$0.199	$0.199	$0.099	-	-	-	**$0.463**
Outside Services	$0.137	$(0.039)	$0.149	$0.149	$0.075	-	-	-	**$0.471**
Business Expense/Overheads	-	$0.010	$0.014	$0.014	$0.007	-	-	-	**$0.045**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.628	$0.744	$0.781	$0.781	-	-	-	**$2.933**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.138	$0.564	$1.106	$1.143	$0.962	-	-	-	**$3.912**

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	$0.138	$0.596	$1.137	$1.174	$0.993	$0.031	-	-	**$4.068**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.138	$(0.002)	$0.758	$0.871	$0.690	$(0.122)	-	-	**$2.332**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.570

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Genesys Cloud Migration | **Report Pulled: 4/23/2025** | **Item ID: 13423**

EXECUTIVE SUMMARY

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 ciruict 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 + $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.

GM-GIS Connectivity Model Integration

Report Pulled: 4/23/2025 **Item ID: 6773**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias GM - GIS Connectivity Model Integration, GM-GIS Connectivity Model Integration

Description The Grid Modernization (GM) Geographic Information System (GIS) Connectivity Model Integration project will design, develop, and implement a GIS extract using an industry standard to publish electric GIS data to the network, where it can be consumed by multiple applications. The extract will make the data available to the electric metering historian as well as other applications in the future.

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

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-TRANS, OPS SUPPORT AND ENG

WORK OBJECTIVES

Problem Statement Interfaces between systems are currently designed, developed and implemented based on requirements that are specific to a particular project or system, while using an application to application (point to point) communications architecture. Maintaining these custom developed integrations is costly and complex.

Objectives The project provides value to the Company by: (1) leveraging the International Electrotechnical Commission (IEC) Common Information Model (CIM), which provides a basic ontology for data and data relationships and a standard repeatable approach that can be leveraged for sharing data about the electrical network across technical systems; (2) supporting an enterprise application integration framework, which keeps business process as simple as possible; (3) providing the ability to detect the physical location of metered assets, including circuit, substations and transformers; and (4) reducing the costs and time required to develop integrations in the future resulting from streamlined approaches and processes.

Scope Deliverables within the project scope include: (1) develop and implement the GIS extract, leveraging IEC CIM for data sharing; (2) leverage the enterprise service bus (ESB) as the high level communications protocol for sharing CIM data across the enterprise; (3) build the integration to the electric metering historian; and (4) develop a data and integration framework that can be leveraged for future projects.

Alternatives The alternative considered was to continue to implement point-to-point application-specific integrations to meet the requirements specific to a single project. This alternative was not chosen because it continues to increase the technical debt associated with the maintenance of non-standard interfaces. The preferred approach as outlined in this business case will result in: (1) standard, repeatable approaches for future integrations, (2) lower ongoing maintenance costs and, (3) less complexity.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/1/2017	7/1/2017	9/30/2019	11/15/2021
	In-Service/Go-Live	**Closeout**	
	11/30/2021	12/31/2021	

FUNDING SUMMARY

	2019	2020	2021	2022	2023	2024	2025	2026 +	Total
Cap+COR	$0.060	-	$0.064	$0.631	$0.114	-	-	-	$0.868
O&M	-	-	$0.083	$0.031	$0.041	$0.047	$0.024	$0.020	$0.246
Total Cost of Ownership	$0.060	-	$0.147	$0.662	$0.155	$0.047	$0.024	$0.020	**$1.114**

	2019	2020	2021	2022	2023	2024	2025	2026 +	Total
Labor	$0.007	-	-	$0.078	$0.031	-	-	-	**$0.116**
Outside Services	$0.007	-	$0.142	$0.523	$0.074	$0.047	-	-	**$0.792**
Business Expense/Overheads	$0.047	-	$0.005	$0.061	$0.049	-	-	-	**$0.162**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.060	-	$0.147	$0.662	$0.155	$0.047	-	-	**$1.070**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2019	2020	2021	2022	2023	2024	2025	2026 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	$0.083	$0.031	$0.041	$0.047	$0.024	$0.020	**$0.246**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	$0.083	$0.031	$0.041	$0.047	$0.024	$0.020	**$0.246**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.060	-	$0.064	$0.631	$0.114	-	-	-	**$0.868**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.060	-	$0.064	$0.631	$0.114	-	-	-	**$0.868**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	Medium	High	Implementation of this project will avoid the risks of data becoming out of sync due to non-standard integrations between systems.

OTHER VALUE

Type	Description
Avoided Costs	Minimize effort when adapting to integration between new systems and minimizes integration changes when applications are changed to add functionality or upgrades.
Avoided Costs	New applications requiring the Electric Distribution network model will not have to build a point to point interface with Electric GIS, so they will require less effort. It is estimated that each interface will save 240 hours of labor effort.

HR Support Pack and Business Software Inc Upgrade 2023

Report Pulled: 4/23/2025 **Item ID: 12506**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias , HR Support Pack and Business Software Inc Upgrade 2023

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-CORPORATE

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 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.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/6/2023	2/27/2023	4/3/2023	4/24/2023
	In-Service/Go-Live	**Closeout**	
	12/22/2023	12/29/2023	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.606	$0.016	-	-	-	-	-	-	$0.622
Total Cost of Ownership	$0.606	$0.016	-	-	-	-	-	-	**$0.622**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.074	$0.003	-	-	-	-	-	-	**$0.077**
Outside Services	$0.495	$0.013	-	-	-	-	-	-	**$0.508**
Business Expense/Overheads	$0.037	-	-	-	-	-	-	-	**$0.037**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.001	-	-	-	-	-	-	-	**$0.001**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.606	$0.016	-	-	-	-	-	-	**$0.622**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.606	$0.016	-	-	-	-	-	-	**$0.622**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.606	$0.016	-	-	-	-	-	-	**$0.622**
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 2024

Report Pulled: 4/23/2025 **Item ID: 12507**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias , HR Support Pack and Business Software Inc Upgrade 2024

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 & SEI

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 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.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/5/2024	3/1/2024	4/1/2024	11/1/2024
	In-Service/Go-Live	**Closeout**	
	12/21/2024	12/31/2024	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	-	-	$0.483	-	-	-	-	-	$0.483
Total Cost of Ownership	-	-	$0.483	-	-	-	-	-	**$0.483**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	-	-	$0.076	-	-	-	-	-	**$0.076**
Outside Services	-	-	$0.407	-	-	-	-	-	**$0.407**
Business Expense/Overheads	-	-	-	-	-	-	-	-	**-**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	-	-	$0.483	-	-	-	-	-	**$0.483**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	$0.483	-	-	-	-	-	**$0.483**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	$0.483	-	-	-	-	-	**$0.483**
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 2025

Report Pulled: 4/23/2025 **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 & SEI

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	$0.642	-	-	-	-	-	-	-	$0.642
Total Cost of Ownership	$0.642	-	-	-	-	-	-	-	**$0.642**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.097	-	-	-	-	-	-	-	**$0.097**
Outside Services	$0.506	-	-	-	-	-	-	-	**$0.506**
Business Expense/Overheads	$0.039	-	-	-	-	-	-	-	**$0.039**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.642	-	-	-	-	-	-	-	**$0.642**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.642	-	-	-	-	-	-	-	**$0.642**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.642	-	-	-	-	-	-	-	**$0.642**
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: 4/23/2025 **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 & SEI

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 2/5/2026
Project Plan & Scope Definition 2/26/2026
Final Engineering, Planning & Design 3/31/2026
Execution 11/1/2026
In-Service/Go-Live 12/19/2026
Closeout 12/31/2026

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.596	-	-	-	-	-	-	-	$0.596
Total Cost of Ownership	$0.596	-	-	-	-	-	-	-	**$0.596**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.097	-	-	-	-	-	-	-	**$0.097**
Outside Services	$0.460	-	-	-	-	-	-	-	**$0.460**
Business Expense/Overheads	$(0.033)	-	-	-	-	-	-	-	**$(0.033)**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	$0.072	-	-	-	-	-	-	-	**$0.072**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.596	-	-	-	-	-	-	-	**$0.596**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.596	-	-	-	-	-	-	-	**$0.596**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.596	-	-	-	-	-	-	-	**$0.596**
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: 4/23/2025 **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 & SEI

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
2/6/2027	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	$0.596	-	-	-	-	-	-	-	$0.596
Total Cost of Ownership	$0.596	-	-	-	-	-	-	-	**$0.596**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.097	-	-	-	-	-	-	-	**$0.097**
Outside Services	$0.460	-	-	-	-	-	-	-	**$0.460**
Business Expense/Overheads	$(0.033)	-	-	-	-	-	-	-	**$(0.033)**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.072	-	-	-	-	-	-	-	**$0.072**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.596	-	-	-	-	-	-	-	**$0.596**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.596	-	-	-	-	-	-	-	**$0.596**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.596	-	-	-	-	-	-	-	**$0.596**
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 SCADA Upgrade

Report Pulled: 4/23/2025 **Item ID: 13968**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Initiative

Alias , HVD SCADA Upgrade

Description 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.

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

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

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 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.

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) 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
3/3/2025	3/17/2025	6/23/2025	4/20/2026
	In-Service/Go-Live	**Closeout**	
	5/5/2026	6/8/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$2.317	$0.503	-	-	-	-	-	$2.820
O&M	-	$0.147	$0.211	$0.070	$0.070	$0.070	-	-	$0.567
Total Cost of Ownership	-	$2.464	$0.714	$0.070	$0.070	$0.070	-	-	**$3.388**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.138	$0.184	-	-	-	-	-	**$0.322**
Outside Services	-	$0.100	$0.250	-	-	-	-	-	**$0.350**
Business Expense/Overheads	-	$0.526	$0.280	$0.070	$0.070	$0.070	-	-	**$1.016**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$1.700	-	-	-	-	-	-	**$1.700**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$2.464	$0.714	$0.070	$0.070	$0.070	-	-	**$3.388**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.147	$0.211	$0.070	$0.070	$0.070	-	-	**$0.567**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.147	$0.211	$0.070	$0.070	$0.070	-	-	**$0.567**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$2.317	$0.503	-	-	-	-	-	**$2.820**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$2.317	$0.503	-	-	-	-	-	**$2.820**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Material Weakness in IT General Computer	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.
Technology Capability	Expanded Technical Capacity. Minimize risk of maintaining associated applications for improved monitoring capabilities.

Integrated Energy Management Platform Optimization

Report Pulled: 4/23/2025 **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 PCI's bid to build process. ADD IN % OF OTHER UTILITIES USING PCI. (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	$4.030	$0.088	-	-	-	-	-	-	$4.118
O&M	$2.211	$0.048	-	-	-	-	-	-	$2.259
Total Cost of Ownership	$6.241	$0.136	-	-	-	-	-	-	**$6.377**

	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	$0.268	-	-	-	-	-	-	-	**$0.268**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$3.358	-	-	-	-	-	-	-	**$3.358**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$5.553	$0.136	-	-	-	-	-	-	**$5.689**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.211	$0.048	-	-	-	-	-	-	**$2.259**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.211	$0.048	-	-	-	-	-	-	**$2.259**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$4.030	$0.088	-	-	-	-	-	-	**$4.118**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$4.030	$0.088	-	-	-	-	-	-	**$4.118**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Integrated Energy Management Platform Optimization

Report Pulled: 4/23/2025 **Item ID: 14021**

EXECUTIVE SUMMARY

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: 4/23/2025 **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 & SER

WORK OBJECTIVES

Problem Statement The application will be at least 1 major upgrade revision behind by 2026. It's imperative our 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, our 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 bring ensure all other platform components comply with our company 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) delay the upgrade and continue operating 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) 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	2/1/2026	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	$0.720	-	-	-	-	-	-	-	$0.720
O&M	$0.276	-	-	-	-	-	-	-	$0.276
Total Cost of Ownership	$0.996	-	-	-	-	-	-	-	**$0.996**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.475	-	-	-	-	-	-	-	**$0.475**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	$0.146	-	-	-	-	-	-	-	**$0.146**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.080	-	-	-	-	-	-	-	**$0.080**
Licenses, Permits & Fees	$0.295	-	-	-	-	-	-	-	**$0.295**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.996	-	-	-	-	-	-	-	**$0.996**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.276	-	-	-	-	-	-	-	**$0.276**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.276	-	-	-	-	-	-	-	**$0.276**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.720	-	-	-	-	-	-	-	**$0.720**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.720	-	-	-	-	-	-	-	**$0.720**
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.

IT Operations Management - Service Operations

Report Pulled: 4/23/2025 **Item ID: 13929**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , IT Operations Management - Service Operations

Description This project will implement an application service mapping tool to effectively manage business-critical services through identification of infrastructure components and application interactions. This tool automates the mapping process to create a complete, up-to-date, and accurate record of the mapped application service in the Database. Application service mapping works hand-in-hand with asset discovery, building on discovered infrastructure data to identify all the assets that support a service, and along with their service-specific relationships.

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

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

WORK OBJECTIVES

Problem Statement As the IT systems steadily increase in complexity and evolve faster than the IT organization can respond to system issues in an optimized and cost-effective manner, the current configuration of the system does not provide the clarity needed in order to understand how the infrastructure interacts with the applications within the IT System it supports and in order to respond to emergent IT incidents in the most rapid and costs effective manner. These constraints can lead to lengthy response and implementation times; negligible or ineffective resolutions; reduced functionality; and elongated outage times in the infrastructure and applications in the system.

Objectives This project will create value for the Company by mapping critical application services through discovery of the underlying infrastructure associated with application services and its relationship to parent business applications. Specifically, by creating application service maps, this project will: (1) increase visibility and understanding between IT infrastructure and Configuration Items; (2) improve accuracy through real-time, automatically updated infrastructure and component changes; (3) reduce IT Subject Matter Expert time on emergent IT issues; (4) Utilize IT Service Management processes; and (5) Reduce downtime by identifying dependences and impact analysis.

Scope The project scope includes: (1) implementation of On-Premise application service maps which have significant business impact; and (2) establishment of process roles needed to support service maps built.

Alternatives Alternatives considered included: (1) Choose an alternate IT Operations Management System with Cloud capabilities. This alternative was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not chosen as there would be a correlation gap between application services and the underlying infrastructure and would not address the ever-increasing resolution costs. (4) Develop and implement an on-premises service mapping and process solution. This alternative was chosen due to the value in Information Technology (IT) Operations Management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can utilize the Configuration Management Database (CMDB) and work hand-in-hand with asset discovery.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
10/1/2023	12/1/2023	12/31/2023	1/1/2024
	In-Service/Go-Live	**Closeout**	
	3/9/2024	3/30/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$2.812	$0.200	-	-	-	-	-	-	$3.012
O&M	$0.634	$0.066	$0.015	$0.015	$0.015	$0.015	-	-	$0.760
Total Cost of Ownership	$3.446	$0.266	$0.015	$0.015	$0.015	$0.015	-	-	**$3.772**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.002	$0.007	-	-	-	-	-	-	**$0.009**
Outside Services	$0.074	$0.203	-	-	-	-	-	-	**$0.277**
Business Expense/Overheads	$0.028	$0.056	-	-	-	-	-	-	**$0.084**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$3.342	-	-	-	-	-	-	-	**$3.342**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.446	$0.266	-	-	-	-	-	-	**$3.712**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.634	$0.066	$0.015	$0.015	$0.015	$0.015	-	-	**$0.760**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.634	$0.066	$0.015	$0.015	$0.015	$0.015	-	-	**$0.760**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.812	$0.200	-	-	-	-	-	-	**$3.012**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.812	$0.200	-	-	-	-	-	-	**$3.012**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

IT Operations Management - Service Operations

EXECUTIVE SUMMARY

Report Pulled: 4/23/2025 **Item ID: 13929**

OTHER VALUE

Type	Description
Intangibles	By implementing ITOM application service mapping it enables the Top-Down Service aware CMDB that can utilize Information Technology Service Management processes and helps in quicker Business Impact determination which will help prioritize the actions and decisions for future enhancements.
Technology Capability	By implementing ITOM Application Service Mapping there will be better Administrative & General (A&G) Support, as this provides visibility into how the infrastructure is connected to applications. It will create a more Service aware configuration management which will improve technical impact Analysis and prioritization leading to a reduction in downtime, better root cause analysis of incidents for the operations teams, and efficient change management.
Avoided Costs	Improving the MTTR (Mean Time to Resolution) for major incidents is one of the primary uses for having services mapped. Understanding the relationships between all of the CIs that make up a service, and easily seeing recent Incidents and Changes on those CIs, provides invaluable insight in both ensuring the Incident is routed to the right team quickly, and in troubleshooting an active issue. Projected Cost Saving - 30% of total labor cost - about $420K on Non-MI MTTR (Customer impacting P2 incidents - Performance/Degradation) and $360K on MI MTTR (P1 and P2 Critical incidents).
Technology Capability	Service Mapping makes the IT process more reliable with Automated mapping services that reduces the time users are handling errors and also enabling the mapping to be updated in real time.

Itron Enterprise Edition 2025 Upgrade

Report Pulled: 4/23/2025 **Item ID: 11761**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias Itron Enterprise Edition Upgrade, Itron Enterprise Edition 2025 Upgrade, Itron Enterprise Edition 2024 Upgrade, Itron Enterprise Edition 2026 Upgrade, Itron Enterprise Edition 2025 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 > 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.

Alternatives Alternatives considered included: (1) Defer the upgrade. This alternative was not selected because it would decouple Itron IEE (CE'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 use, creating more expense to support and no ability to leverage updated tool capability. (2) Replace 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 multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform the upgrade. This option is superior for both our customers and our 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
7/29/2025	8/12/2025	10/24/2025	5/1/2026
	In-Service/Go-Live	**Closeout**	
	5/20/2026	6/9/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.131	$0.131	-	-	-	-	-	-	$0.261
Total Cost of Ownership	$0.131	$0.131	-	-	-	-	-	-	**$0.261**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.122	$0.122	-	-	-	-	-	-	**$0.244**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	$0.009	$0.009	-	-	-	-	-	-	**$0.017**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.131	$0.131	-	-	-	-	-	-	**$0.261**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.131	$0.131	-	-	-	-	-	-	**$0.261**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.131	$0.131	-	-	-	-	-	-	**$0.261**
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	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.

OTHER VALUE

Type	Description
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.

Itron Enterprise Edition 2027 Upgrade

Report Pulled: 4/23/2025 **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 included: (1) Defer the upgrade. This alternative was not selected because it would decouple Itron IEE (CE'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 use, creating more expense to support and no ability to leverage updated tool capability. (2) Replace 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 multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform the upgrade. This option is superior for both our customers' and our 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	$0.366	-	-	-	-	-	-	-	$0.366
O&M	$0.498	-	-	-	-	-	-	-	$0.498
Total Cost of Ownership	$0.863	-	-	-	-	-	-	-	**$0.863**

	2027	2028	2029	2030	2031	2032	2033	2034 +	Total
Labor	$0.465	-	-	-	-	-	-	-	**$0.465**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	$0.148	-	-	-	-	-	-	-	**$0.148**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.250	-	-	-	-	-	-	-	**$0.250**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.863	-	-	-	-	-	-	-	**$0.863**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2027	2028	2029	2030	2031	2032	2033	2034 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.498	-	-	-	-	-	-	-	**$0.498**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.498	-	-	-	-	-	-	-	**$0.498**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.366	-	-	-	-	-	-	-	**$0.366**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.366	-	-	-	-	-	-	-	**$0.366**
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.

Live Wiredown Detection and ADMS Upgrade

Report Pulled: 4/23/2025 **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	$0.010	$0.010	$0.010	$0.010	-	-	$0.085
Total Cost of Ownership	$0.312	$1.298	$0.010	$0.010	$0.010	$0.010	-	-	**$1.648**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.072	$0.763	-	-	-	-	-	-	**$0.835**
Outside Services	$0.076	$0.308	-	-	-	-	-	-	**$0.385**
Business Expense/Overheads	$0.016	$0.226	-	-	-	-	-	-	**$0.242**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.003	-	-	-	-	-	-	-	**$0.003**
Licenses, Permits & Fees	$0.146	$0.000	$0.010	$0.010	$0.010	$0.010	-	-	**$0.184**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.312	$1.298	$0.010	$0.010	$0.010	$0.010	-	-	**$1.648**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.024	$0.022	$0.010	$0.010	$0.010	$0.010	-	-	**$0.085**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.024	$0.022	$0.010	$0.010	$0.010	$0.010	-	-	**$0.085**
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

Live Wiredown Detection and ADMS Upgrade

EXECUTIVE SUMMARY

Report Pulled: 4/23/2025

Item ID: 10474

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

Multi-Account Online Account Management

Report Pulled: 4/23/2025 **Item ID: 9037**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Super User Capability, Commercial and Industrial Online Account Management, Multi-Account Online Account Management

Description The project will enable additional features supporting both Commercial and Industrial and residential customers' ability to manage their accounts online. This project was formerly known as the Commercial and Industrial Online Account Management project. This enables customers to combine multiple accounts under a single login and assign authorizations to various location managers and would also establish a payment process for collective billing and self-service account management scenarios. Customers who use Bill Trust today can make one payment that covers multiple accounts, but the functionality is very limited and they can't manage the payment very well.

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 The Company supports business customers of varying sizes which may alter how the accounts are established in the back-end system. Customers such as large universities may require multiple entries in the system to support all of their locations, requiring multiple logins to the self-service portal and several bills to be prepared.
The initial C&I tool was scoped to reach business customers with multiple accounts. The broader scoped multi-account project will also reach residential customers who have
•More than one property
•More than one meter/account (Outbuildings etc.)
•Multiple accounts due to moving and/or new building
•3K accounts (non-energy billing accounts)

Development of this tool directly addresses customer feedback that this specific issue is burdening their ability to manage and pay their utility bills, which is the most important transaction a customer has with the Company. When this is not functional, not only does the Company lose the efficiency, accuracy, and security of online account management and billing, but also the opportunity to opt-in, learn more or otherwise engage with Consumer's EWR and other retail offerings central to the Company and Michigan's clean energy strategies.

Objectives The Company and both C&I and residential customers will see value through: (1) improved customer self-service portal for managing multiple accounts, (2) reduced touchpoints for billing inquiries, (3) ability for customers to select their bill due date, and (4) customers enabled to make a single payment on a collective bill.

Scope The scope of this project includes: (1) modifying the self-service customer portal to support managing multiple accounts under a single login replacement of an existing third-party solution that does not meet customer expectations, (2) modifying SAP to align customer accounts in an organized hierarchy, (3) updating single sign-on process to enable the customer's authorized resources (such as bookkeepers, accountants, CPAs, or attorneys) to manage the account, and (4) establishing a payment process for collective billing.

Alternatives Alternatives considered include: (1) Providing training to administrators of large customer accounts to better utilize the current third-party solution, which is not user-friendly and prone to errors resulting in rework to correct. This option was not selected as it does not improve customer satisfaction. (2) Utilizing Company resources to aid in administering the customer's accounts and collective billing. The Company did not select this option as it prevents the customer from self-serving their account(s) while increasing the cost of Business Contact Center resources. (3) Replacing the existing third-party solution with a cloud solution. This option was not selected because all of the other data and systems are currently on-premise and it is not cost effective to move to the cloud. (4) Replacing the existing third-party solution with an in-house solution. This option was selected as it the most cost-effective compared to the alternatives and provides the most flexibility to meet customer needs for bill payment, reviewing their energy usage, and authorizing others to manage select accounts.

DATES (phase end)

Initiation 7/1/2027	**Project Plan & Scope Definition** 7/31/2027	**Final Engineering, Planning & Design** 9/1/2027	**Execution** 3/26/2028
	In-Service/Go-Live 3/31/2028	**Closeout** 4/17/2028	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	$3.907	$1.153	-	-	-	-	-	$5.060
O&M	-	$0.933	$0.298	$0.050	$0.050	$0.050	$0.050	-	$1.431
Total Cost of Ownership	-	$4.840	$1.451	$0.050	$0.050	$0.050	$0.050	-	**$6.492**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	-	$0.653	$0.326	-	-	-	-	-	**$0.979**
Outside Services	-	$3.702	$0.882	$0.050	$0.050	$0.050	$0.050	-	**$4.784**
Business Expense/Overheads	-	$0.486	$0.243	-	-	-	-	-	**$0.729**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$4.840	$1.451	$0.050	$0.050	$0.050	$0.050	-	**$6.492**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	$(0.269)	$(0.359)	$(0.359)	$(0.359)	-	-	-	**$(1.344)**
	Initial	-	$0.933	$0.298	$0.050	$0.050	$0.050	$0.050	-	**$1.431**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.664	$(0.061)	$(0.309)	$(0.309)	$0.050	$0.050	-	**$0.087**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$3.907	$1.153	-	-	-	-	-	**$5.060**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$3.907	$1.153	-	-	-	-	-	**$5.060**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-

Multi-Account Online Account Management

Report Pulled: 4/23/2025 **Item ID: 9037**

EXECUTIVE SUMMARY

Incremental	-	-	-	-	-	-	-	-	-
Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.832

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Contact Center calls could be reduced 25%. Average call length regarding this issue is 25mins, equating to $50. 22,000 calls could be saved at $50 per call equating to 1.1M soft savings.
Avoided Costs	Currently many billing exceptions are generated, requiring manual intervention from billing specialists. This application would reduce the need for a majority of the manual fixing/reprocessing.
Avoided Costs	Cyber Security has reported the existing Small Medium Business/Landlord platform has 58 critical/high vulnerabilities, with roughly 300 total including lower priority items. Correcting all of the vulnerabilities would likely exceed the costs of replacing the necessary capability within the proposed solution for C&I Account Management.
Intangibles	More efficient work processes for Energy Solution Managers with automated collective billing processes. Customers will have the ability to self-serve, reducing the need for ESMs to support this feature.

Operational Technology - Service Management Upgrade

Report Pulled: 4/23/2025 **Item ID: 13924**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , ServiceNow OT Module, Operational Technology - Service Management, Operational Technology - Service Management Upgrade

Description This project will implement Operational Technology ("OT") service management capabilities. Service management provides automated asset tracking, maintenance, and incident management for the assets.

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

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

WORK OBJECTIVES

Problem Statement The Company' Internal Audit team conducted an audit of the Operational Technology (OT) asset environment and identified significant gaps in the patch management program. The patch management operating model is decentralized, has limited and inconsistent standards, doesn't have a company-wide governance structure to monitor all business areas of the Company and lacks a complete and accurate asset inventory. Due to the lack of a complete asset inventory, as well as a significant number of gaps identified in the patch management governance, operating model, processes, and controls to manage all assets within the Company's environment, an unknown magnitude of risk exists that critical patches were not installed timely, which could create the potential for increased security vulnerabilities.

Objectives The project provides value to the Company in three ways 1.) Establishes a complete and accurate asset inventory. 2.) Creates a Company-wide governance structure with documented standards and processes to manage the assets and 3.) Defines a comprehensive patch management operating model with clearly defined roles and responsibilities.

Scope The project scope includes: (1) the implementation of an asset management tool (2) the implementation of an incident management tool, (3) and the establishment of process roles needed to support the assets.

Alternatives Alternatives considered included: (1) Choose a Cloud-based alternate asset management system. This option was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. Continue to manually track or not track Operational Technology (OT) Digital assets at the Company, which will not address the need to effectively track OT Digital assets and plan for their support. (4) Develop and implement an asset management and incident management tool and processes. This alternative ultimately chosen has strengths in Information Technology (IT) service management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can help bridge the gap between IT and OT, enable the Company to manage both types of assets through a single interface.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
10/1/2023	11/4/2023	12/1/2023	12/3/2023
	In-Service/Go-Live	**Closeout**	
	3/7/2024	3/29/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.729	$0.166	-	-	-	-	-	-	$0.895
O&M	$0.148	$0.044	$0.005	$0.005	$0.005	$0.005	-	-	$0.212
Total Cost of Ownership	$0.877	$0.210	$0.005	$0.005	$0.005	$0.005	-	-	**$1.107**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.026	$0.038	-	-	-	-	-	-	**$0.065**
Outside Services	$0.039	$0.122	-	-	-	-	-	-	**$0.161**
Business Expense/Overheads	$0.009	$0.050	-	-	-	-	-	-	**$0.060**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.803	-	-	-	-	-	-	-	**$0.803**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.877	$0.210	-	-	-	-	-	-	**$1.087**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.148	$0.044	$0.005	$0.005	$0.005	$0.005	-	-	**$0.212**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.148	$0.044	$0.005	$0.005	$0.005	$0.005	-	-	**$0.212**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.729	$0.166	-	-	-	-	-	-	**$0.895**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.729	$0.166	-	-	-	-	-	-	**$0.895**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Operational Technology - Service Management Upgrade

Report Pulled: 4/23/2025 **Item ID: 13924**

EXECUTIVE SUMMARY

OTHER VALUE

Type	Description
Technology Capability	Consolidating Operational Technology Assets into a single database establishes the groundwork for potential future service management capabilities such as incident management, change management, and vulnerability management for the Operational Technology Team, all of which are poised to enhance operational performance.
Intangibles	Having Operational Technology Assets in one database will improve efficiencies (with data stored in a single system, resources spend less time searching for information across multiple platforms, leading to increased productivity and faster decision making), increase accuracy (centralizing data reduces the likelihood of errors and inconsistencies that can occur when information is spread across disparate systems), better collaboration (one system encourages collaboration across teams. This fosters teamwork and enhances communication within the organization), better insights (having data in a single database facilitates comprehensive analysis and reporting. This allows for deeper insights into operations, trends and enable informed decision making). Overall, having data in one system simplifies operations, enhances efficiency, and empowers the company to make better informed decisions.

Operational Technology (OT) Datacenter Migration

Report Pulled: 4/23/2025 **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 & SEI

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	$6.877	$0.872	-	-	-	-	-	-	$7.750
O&M	$2.311	$3.985	$1.816	$1.816	-	-	-	-	$9.928
Total Cost of Ownership	$9.188	$4.857	$1.816	$1.816	-	-	-	-	**$17.677**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.600	$0.550	-	-	-	-	-	-	**$1.150**
Outside Services	$1.045	$1.040	-	-	-	-	-	-	**$2.085**
Business Expense/Overheads	$2.033	$1.451	-	-	-	-	-	-	**$3.484**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$5.010	-	-	-	-	-	-	-	**$5.010**
Licenses, Permits & Fees	$0.500	-	-	-	-	-	-	-	**$0.500**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$9.188	$3.041	-	-	-	-	-	-	**$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	$6.877	$0.872	-	-	-	-	-	-	**$7.750**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$6.877	$0.872	-	-	-	-	-	-	**$7.750**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Operational Technology (OT) Datacenter Migration *EXECUTIVE SUMMARY*	**Report Pulled: 4/23/2025**	**Item ID: 13963**
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.	
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.	

Physical Access Management and Alarm Response

Report Pulled: 4/23/2025 **Item ID: 13976**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Physical Access Management and Alarm Response

Description The project will replace the Company's Physical Access Management System to establish a centralized platform that manages user identities, authenticates users, authorizes access, and audits user activities. The intent of this project is to consolidate and modernize the Company's physical security systems that will enable enhanced security monitoring to prevent unauthorized entry into sensitive corporate areas while providing increased flexibility to the Company's valued employees and contractors.

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

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

WORK OBJECTIVES

Problem Statement

The Company's Security Fusion Center (the Fusion Center is the Company's combined physical and cyber security operations center) is experiencing operational issues with the current physical access management system. The installation is out of date and causes inconsistent behavior when given tasks by automations within the Company's Identity Management solution. Frequent issues have been reported related to frozen jobs in the Company's existing access management solution due to the current system's database. This results in significant waste in the form of (1) waiting, the business partner is waiting much longer than they should have for the system to process their request as un-freezing jobs is a manual process; (2) lost productivity, that waiting can cause for the business partner as it can either prevent them from accessing sites they need, or slow them down unnecessarily while they work with others to be escorted; (3) rework, because frozen jobs do not always run correctly when unfrozen, meaning the business partner has to resubmit their request and/or Identity Operations has to do additional work to satisfy the original request; and (4) alarms can cause a frozen state that impact system stability and reduces security visibility as a result. Not moving to new technology also carries a growing risk of outright system failure which could result in unauthorized physical access and/or impact the Company's ability to efficiently function. The current installation of the physical access management system and the Company's current card readers do not support next generation physical access control methods, such as digital ID. This prevents the Company from adopting new methods and practices that can lower costs and improve control and responsiveness. All employees, contractors, staff, and visitors are impacted by the problem.

Objectives

This project creates value for the Company by: (1) developing an alarm and event monitoring system, which will enable seamless orchestration of system alarms and cameras; (2) adding automation that will streamline remediation processes and orchestrate camera operations for efficiency; (3) refining access revocation and badge access management to ensure only authorized personnel have entry privileges; and (4) introducing new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company's facilities.

Scope

The project scope includes modernizing the Company's current physical access control system, badge system, badge access hardware and firmware, and all 3000 card readers across facilities and assets. This will require modernization of all physical badge access readers and the implementation of hardware and software necessary to run the physical access control system. In addition, there will be substantial automation and integration between the security orchestration solution and the physical access control systems to realize the full benefits of this initiative.

Alternatives

Alternatives considered were: (1) Keeping the current physical access control system and processes as-is. This alternative was not selected as the current platform is outdated, increasingly expensive to support, and does not include modern capabilities, such as digital IDs. It also does not reduce waste, cost, and it does not improve speed to delivery; (2) Developing a custom, in-house physical access control solution that includes modern capabilities, such as digital IDs. This option was not selected as the Company lacks the expertise to build such a solution. Custom-developed solutions have higher long-term, and generally result in significant waste, as well as lower speed to delivery; and (3) Implementing a new physical access control system that includes modern capabilities, such as digital IDs, that reduces waste and cost and improves speed to delivery. There are vendors in the market that specialize in physical access control systems that offer proven capabilities the Company is looking to implement. This option was selected as it will allow the Company to meet its objectives of lower waste, lower cost, improved speed to delivery, by implementing digital IDs and enabling tighter integration between the physical access control system and the Company's other security platforms.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/15/2026	2/28/2026	4/28/2026	2/25/2027
	In-Service/Go-Live	**Closeout**	
	2/26/2027	12/1/2029	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$3.234	$1.551	$1.551	-	-	-	-	-	$6.335
O&M	$0.328	$0.345	$0.345	$0.187	-	-	-	-	$1.205
Total Cost of Ownership	$3.562	$1.896	$1.896	$0.187	-	-	-	-	**$7.540**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.419	$0.388	$0.388	$0.187	-	-	-	-	**$1.382**
Outside Services	$0.225	$0.135	$0.135	-	-	-	-	-	**$0.495**
Business Expense/Overheads	$0.280	$0.143	$0.143	-	-	-	-	-	**$0.565**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$1.130	$1.125	$1.125	-	-	-	-	-	**$3.380**
Licenses, Permits & Fees	$1.508	$0.105	$0.105	-	-	-	-	-	**$1.718**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.562	$1.896	$1.896	$0.187	-	-	-	-	**$7.540**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.328	$0.345	$0.345	$0.187	-	-	-	-	**$1.205**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.328	$0.345	$0.345	$0.187	-	-	-	-	**$1.205**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$3.234	$1.551	$1.551	-	-	-	-	-	**$6.335**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$3.234	$1.551	$1.551	-	-	-	-	-	**$6.335**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-

Physical Access Management and Alarm Response

Report Pulled: 4/23/2025 **Item ID: 13976**

EXECUTIVE SUMMARY

Incremental	-	-	-	-	-	-	-	-	-
Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
System Failure (SAP & Other)	Medium	Medium	This system replacement will reduce current operating risk managing multiple physical access management platforms.

OTHER VALUE

Type	Description
Technology Capability	Access revocation and badge access management will be refined to ensure only authorized personnel have entry privileges
Technology Capability	Development of a sophisticated Alarm and Event monitoring system will enable seamless orchestration of system alarms and cameras. This will facilitate proactive camera monitoring and rapid response to incidents.
Technology Capability	The impact of the project is to allow physical entry for employees, contractors, and visitors who are authorized to do work for the Company while minimizing barriers.
Technology Capability	The new system will introduce new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company's facilities.
Technology Capability	The new system will seamlessly integrate with mobile badging, allowing for efficient contractor and visitor management, which is particularly crucial during emergency situations such as storms.
Technology Capability	The project will give the ability to integrate badge entry data with security camera data and other security platforms to perform cross system monitoring and flagging. This impact will allow the Company to build more effective alerts that can be responded to in a more deliberate manner.

Product Family Enhancements-Application Platforms Servic Report Pulled: 4/23/2025 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 & SER

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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.389	$0.956	$0.733	$0.733	$0.733	$0.733	-	-	$4.278
O&M	$0.008	$0.132	$0.166	$0.166	$0.166	$0.166	-	-	$0.805
Total Cost of Ownership	$0.397	$1.088	$0.899	$0.899	$0.899	$0.899	-	-	**$5.082**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.203	$0.625	$0.634	$0.634	$0.634	$0.634	-	-	**$3.363**
Outside Services	$0.098	$0.157	-	-	-	-	-	-	**$0.255**
Business Expense/Overheads	$0.059	$0.306	$0.265	$0.265	$0.265	$0.265	-	-	**$1.427**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.008	-	-	-	-	-	-	-	**$0.008**
Licenses, Permits & Fees	$0.030	-	-	-	-	-	-	-	**$0.030**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.397	$1.088	$0.899	$0.899	$0.899	$0.899	-	-	**$5.082**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.008	$0.132	$0.166	$0.166	$0.166	$0.166	-	-	**$0.805**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.008	$0.132	$0.166	$0.166	$0.166	$0.166	-	-	**$0.805**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.389	$0.956	$0.733	$0.733	$0.733	$0.733	-	-	**$4.278**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.389	$0.956	$0.733	$0.733	$0.733	$0.733	-	-	**$4.278**
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 Service Report Pulled: 4/23/2025 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 & SER

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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.288	$0.270	$0.167	$0.167	$0.167	$0.167	-	-	$1.226
Total Cost of Ownership	$0.288	$0.270	$0.167	$0.167	$0.167	$0.167	-	-	**$1.226**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.153	$0.229	$0.156	$0.156	$0.156	$0.156	-	-	**$1.006**
Outside Services	$0.090	-	-	-	-	-	-	-	**$0.090**
Business Expense/Overheads	-	$0.041	$0.011	$0.011	$0.011	$0.011	-	-	**$0.085**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.012	-	-	-	-	-	-	-	**$0.012**
Licenses, Permits & Fees	$0.033	-	-	-	-	-	-	-	**$0.033**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.288	$0.270	$0.167	$0.167	$0.167	$0.167	-	-	**$1.226**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.288	$0.270	$0.167	$0.167	$0.167	$0.167	-	-	**$1.226**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.288	$0.270	$0.167	$0.167	$0.167	$0.167	-	-	**$1.226**
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: 4/23/2025 **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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$1.257	$3.849	$2.121	$2.121	$2.045	$2.045	-	-	$13.438
O&M	$0.133	$0.552	$0.311	$0.311	$0.151	$0.151	-	-	$1.610
Total Cost of Ownership	$1.390	$4.401	$2.433	$2.433	$2.196	$2.196	-	-	**$15.048**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.246	$2.976	$1.676	$1.676	$1.476	$1.476	-	-	**$9.526**
Outside Services	$0.624	$0.063	-	-	-	-	-	-	**$0.687**
Business Expense/Overheads	$0.077	$1.362	$0.757	$0.757	$0.720	$0.720	-	-	**$4.393**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.002	-	-	-	-	-	-	-	**$0.002**
Licenses, Permits & Fees	$0.440	-	-	-	-	-	-	-	**$0.440**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.390	$4.401	$2.433	$2.433	$2.196	$2.196	-	-	**$15.048**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.133	$0.552	$0.311	$0.311	$0.151	$0.151	-	-	**$1.610**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.133	$0.552	$0.311	$0.311	$0.151	$0.151	-	-	**$1.610**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.257	$3.849	$2.121	$2.121	$2.045	$2.045	-	-	**$13.438**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.257	$3.849	$2.121	$2.121	$2.045	$2.045	-	-	**$13.438**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Product Family Enhancements-Corporate-O&M

Report Pulled: 4/23/2025 **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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.392	$0.552	$0.200	$0.200	$0.200	$0.200	-	-	$1.742
Total Cost of Ownership	$0.392	$0.552	$0.200	$0.200	$0.200	$0.200	-	-	**$1.742**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.097	$0.516	$0.186	$0.186	$0.186	$0.186	-	-	**$1.359**
Outside Services	$0.295	-	-	-	-	-	-	-	**$0.295**
Business Expense/Overheads	-	-	$0.013	$0.013	$0.013	$0.013	-	-	**$0.052**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.000	$0.036	-	-	-	-	-	-	**$0.036**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.392	$0.552	$0.200	$0.200	$0.200	$0.200	-	-	**$1.742**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.392	$0.552	$0.200	$0.200	$0.200	$0.200	-	-	**$1.742**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.392	$0.552	$0.200	$0.200	$0.200	$0.200	-	-	**$1.742**
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

Product Family Enhancements-Customer-Capital

Report Pulled: 4/23/2025 **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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$1.573	$7.711	$3.807	$2.735	$2.735	$2.735	-	-	$21.295
O&M	$0.862	$0.857	$0.199	$0.124	$0.124	$0.124	-	-	$2.290
Total Cost of Ownership	$2.435	$8.568	$4.006	$2.859	$2.859	$2.859	-	-	**$23.585**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.408	$4.417	$1.132	$0.362	$0.362	$0.362	-	-	**$7.045**
Outside Services	$1.926	$2.140	$2.303	$2.303	$2.303	$2.303	-	-	**$13.278**
Business Expense/Overheads	$0.101	$2.011	$0.562	$0.184	$0.185	$0.185	-	-	**$3.227**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.009	$0.009	$0.009	$0.009	-	-	**$0.036**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$2.435	$8.568	$4.006	$2.859	$2.859	$2.859	-	-	**$23.585**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.862	$0.857	$0.199	$0.124	$0.124	$0.124	-	-	**$2.290**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.862	$0.857	$0.199	$0.124	$0.124	$0.124	-	-	**$2.290**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.573	$7.711	$3.807	$2.735	$2.735	$2.735	-	-	**$21.295**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.573	$7.711	$3.807	$2.735	$2.735	$2.735	-	-	**$21.295**
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: 4/23/2025 **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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.079	$0.432	$0.296	$0.296	$0.296	$0.296	-	-	$1.695
Total Cost of Ownership	$0.079	$0.432	$0.296	$0.296	$0.296	$0.296	-	-	**$1.695**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	-	$0.177	$0.177	$0.177	$0.177	-	-	**$0.706**
Outside Services	$0.079	$0.354	$0.100	$0.100	$0.100	$0.100	-	-	**$0.834**
Business Expense/Overheads	-	$0.077	$0.019	$0.019	$0.019	$0.019	-	-	**$0.155**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.079	$0.432	$0.296	$0.296	$0.296	$0.296	-	-	**$1.695**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.079	$0.432	$0.296	$0.296	$0.296	$0.296	-	-	**$1.695**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.079	$0.432	$0.296	$0.296	$0.296	$0.296	-	-	**$1.695**
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-Capita Report Pulled: 4/23/2025 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$1.538	$0.848	$1.037	$1.037	$1.037	$1.037	-	-	$6.533
O&M	$0.395	$0.065	$0.155	$0.155	$0.155	$0.155	-	-	$1.081
Total Cost of Ownership	$1.933	$0.914	$1.192	$1.192	$1.192	$1.192	-	-	**$7.615**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.263	$0.123	$0.155	$0.155	$0.155	$0.155	-	-	**$1.009**
Outside Services	$1.596	$0.393	$0.843	$0.843	$0.843	$0.843	-	-	**$5.359**
Business Expense/Overheads	$0.071	$0.359	$0.179	$0.179	$0.179	$0.179	-	-	**$1.147**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.003	$0.039	$0.015	$0.015	$0.015	$0.015	-	-	**$0.100**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$1.933	$0.914	$1.192	$1.192	$1.192	$1.192	-	-	**$7.615**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.395	$0.065	$0.155	$0.155	$0.155	$0.155	-	-	**$1.081**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.395	$0.065	$0.155	$0.155	$0.155	$0.155	-	-	**$1.081**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$1.538	$0.848	$1.037	$1.037	$1.037	$1.037	-	-	**$6.533**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$1.538	$0.848	$1.037	$1.037	$1.037	$1.037	-	-	**$6.533**
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: 4/23/2025 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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.072	$0.172	$0.201	$0.201	$0.201	$0.201	-	-	$1.046
Total Cost of Ownership	$0.072	$0.172	$0.201	$0.201	$0.201	$0.201	-	-	**$1.046**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.010	$0.145	$0.143	$0.143	$0.143	$0.143	-	-	**$0.727**
Outside Services	$0.062	$0.013	$0.042	$0.042	$0.042	$0.042	-	-	**$0.244**
Business Expense/Overheads	-	$0.011	$0.013	$0.013	$0.013	$0.013	-	-	**$0.063**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	$0.002	$0.002	$0.002	$0.002	$0.002	-	-	**$0.011**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.072	$0.172	$0.201	$0.201	$0.201	$0.201	-	-	**$1.046**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.072	$0.172	$0.201	$0.201	$0.201	$0.201	-	-	**$1.046**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.072	$0.172	$0.201	$0.201	$0.201	$0.201	-	-	**$1.046**
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: 4/23/2025 **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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.563	$2.188	$1.597	$1.597	$1.597	$1.597	-	-	$9.140
O&M	$0.217	$0.274	$0.242	$0.242	$0.242	$0.242	-	-	$1.460
Total Cost of Ownership	$0.781	$2.462	$1.839	$1.839	$1.839	$1.839	-	-	**$10.600**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.210	$1.216	$0.980	$0.980	$0.980	$0.980	-	-	**$5.345**
Outside Services	$0.779	$0.286	$0.345	$0.345	$0.345	$0.345	-	-	**$2.443**
Business Expense/Overheads	$(0.208)	$0.933	$0.514	$0.514	$0.514	$0.514	-	-	**$2.782**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.027	$0.001	$0.001	$0.001	$0.001	-	-	**$0.030**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.781	$2.462	$1.839	$1.839	$1.839	$1.839	-	-	**$10.600**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.217	$0.274	$0.242	$0.242	$0.242	$0.242	-	-	**$1.460**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.217	$0.274	$0.242	$0.242	$0.242	$0.242	-	-	**$1.460**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.563	$2.188	$1.597	$1.597	$1.597	$1.597	-	-	**$9.140**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.563	$2.188	$1.597	$1.597	$1.597	$1.597	-	-	**$9.140**
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: 4/23/2025 **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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.140	$0.270	$0.256	$0.256	$0.256	$0.256	-	-	$1.433
Total Cost of Ownership	$0.140	$0.270	$0.256	$0.256	$0.256	$0.256	-	-	**$1.433**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.062	$0.230	$0.204	$0.204	$0.204	$0.204	-	-	**$1.106**
Outside Services	$0.076	$0.036	$0.035	$0.035	$0.035	$0.035	-	-	**$0.254**
Business Expense/Overheads	-	-	$0.017	$0.017	$0.017	$0.017	-	-	**$0.067**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.002	$0.001	-	-	-	-	-	-	**$0.002**
Licenses, Permits & Fees	-	$0.003	-	-	-	-	-	-	**$0.003**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.140	$0.270	$0.256	$0.256	$0.256	$0.256	-	-	**$1.433**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.140	$0.270	$0.256	$0.256	$0.256	$0.256	-	-	**$1.433**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.140	$0.270	$0.256	$0.256	$0.256	$0.256	-	-	**$1.433**
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 Serv Report Pulled: 4/23/2025 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 &

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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.548	$1.094	$0.631	$0.631	$0.631	$0.631	-	-	$4.168
O&M	$0.080	$0.149	$0.421	$0.421	$0.421	$0.421	-	-	$1.913
Total Cost of Ownership	$0.628	$1.243	$1.053	$1.053	$1.053	$1.053	-	-	**$6.081**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.257	$0.762	$0.806	$0.806	$0.806	$0.806	-	-	**$4.242**
Outside Services	$0.169	$0.094	-	-	-	-	-	-	**$0.263**
Business Expense/Overheads	$0.054	$0.364	$0.247	$0.247	$0.247	$0.247	-	-	**$1.406**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.147	$0.023	-	-	-	-	-	-	**$0.170**
Licenses, Permits & Fees	$0.000	-	-	-	-	-	-	-	**$0.000**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.628	$1.243	$1.053	$1.053	$1.053	$1.053	-	-	**$6.081**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.080	$0.149	$0.421	$0.421	$0.421	$0.421	-	-	**$1.913**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.080	$0.149	$0.421	$0.421	$0.421	$0.421	-	-	**$1.913**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.548	$1.094	$0.631	$0.631	$0.631	$0.631	-	-	**$4.168**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.548	$1.094	$0.631	$0.631	$0.631	$0.631	-	-	**$4.168**
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 Serv Report Pulled: 4/23/2025 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 &

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

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.134	$0.111	$0.233	$0.233	$0.233	$0.233	-	-	$1.177
Total Cost of Ownership	$0.134	$0.111	$0.233	$0.233	$0.233	$0.233	-	-	**$1.177**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.007	$0.111	$0.218	$0.218	$0.218	$0.218	-	-	**$0.989**
Outside Services	$0.127	-	-	-	-	-	-	-	**$0.127**
Business Expense/Overheads	-	-	$0.015	$0.015	$0.015	$0.015	-	-	**$0.061**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.134	$0.111	$0.233	$0.233	$0.233	$0.233	-	-	**$1.177**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.134	$0.111	$0.233	$0.233	$0.233	$0.233	-	-	**$1.177**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.134	$0.111	$0.233	$0.233	$0.233	$0.233	-	-	**$1.177**
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.

Public Key Infrastructure (PKI) Upgrade

Report Pulled: 4/23/2025 **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 & STAN

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	-	-	-	-	-	-	$1.388
O&M	$0.084	$0.188	-	-	-	-	-	-	$0.272
Total Cost of Ownership	$0.238	$1.422	-	-	-	-	-	-	**$1.660**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.015	$0.239	-	-	-	-	-	-	**$0.254**
Outside Services	$0.016	$0.267	-	-	-	-	-	-	**$0.282**
Business Expense/Overheads	$0.002	$0.135	-	-	-	-	-	-	**$0.137**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.672	-	-	-	-	-	-	**$0.672**
Licenses, Permits & Fees	$0.205	$0.109	-	-	-	-	-	-	**$0.315**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.238	$1.422	-	-	-	-	-	-	**$1.660**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.084	$0.188	-	-	-	-	-	-	**$0.272**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.084	$0.188	-	-	-	-	-	-	**$0.272**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.154	$1.234	-	-	-	-	-	-	**$1.388**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.154	$1.234	-	-	-	-	-	-	**$1.388**
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: 4/23/2025 **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 & SEI

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 project team intensely reviewed 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 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	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/2/2024	1/15/2024	1/31/2024	2/1/2024
	In-Service/Go-Live	**Closeout**	
	3/31/2025	4/30/2025	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.574	$4.723	$0.219	-	-	-	-	-	$5.516
O&M	-	$0.034	$0.328	$0.412	$0.437	$0.462	$0.229	-	$1.901
Total Cost of Ownership	$0.574	$4.756	$0.547	$0.412	$0.437	$0.462	$0.229	-	**$7.417**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.037	$0.240	$0.136	-	-	-	-	-	**$0.413**
Outside Services	$0.405	$0.089	$0.048	-	-	-	-	-	**$0.542**
Business Expense/Overheads	$0.015	$0.068	$0.066	-	-	-	-	-	**$0.149**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.117	$1.201	-	-	-	-	-	-	**$1.318**
Licenses, Permits & Fees	-	$3.159	$0.077	-	-	-	-	-	**$3.236**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.574	$4.756	$0.328	-	-	-	-	-	**$5.658**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.034	$0.328	$0.412	$0.437	$0.462	$0.229	-	**$1.901**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.034	$0.328	$0.412	$0.437	$0.462	$0.229	-	**$1.901**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.574	$4.723	$0.219	-	-	-	-	-	**$5.516**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.574	$4.723	$0.219	-	-	-	-	-	**$5.516**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Ransomware Recovery-OT-Electric & Generation

Report Pulled: 4/23/2025 **Item ID: 13428**

EXECUTIVE SUMMARY

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: 4/23/2025 **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 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.

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 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.

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	-	-	-	-	-	-	-	-	-
O&M	$0.246	$0.298	$0.298	$0.298	$0.298	$0.298	-	-	$1.735
Total Cost of Ownership	$0.246	$0.298	$0.298	$0.298	$0.298	$0.298	-	-	**$1.735**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.013	$0.278	$0.278	$0.278	$0.278	$0.278	-	-	**$1.405**
Outside Services	$0.233	-	-	-	-	-	-	-	**$0.233**
Business Expense/Overheads	-	$0.019	$0.019	$0.019	$0.019	$0.019	-	-	**$0.097**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.246	$0.298	$0.298	$0.298	$0.298	$0.298	-	-	**$1.735**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.246	$0.298	$0.298	$0.298	$0.298	$0.298	-	-	**$1.735**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.246	$0.298	$0.298	$0.298	$0.298	$0.298	-	-	**$1.735**
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: 4/23/2025 **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 & SEI

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	$1.686	-	-	-	-	-	$6.919
O&M	$0.181	$0.840	$0.411	-	-	-	-	-	$1.432
Total Cost of Ownership	$2.572	$3.681	$2.097	-	-	-	-	-	**$8.351**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.101	$0.592	$0.341	-	-	-	-	-	**$1.035**
Outside Services	$0.180	$2.146	$1.489	-	-	-	-	-	**$3.815**
Business Expense/Overheads	$0.035	$0.285	$0.267	-	-	-	-	-	**$0.587**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$2.255	$0.659	-	-	-	-	-	-	**$2.914**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$2.572	$3.681	$2.097	-	-	-	-	-	**$8.351**

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	$0.411	-	-	-	-	-	**$1.432**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.181	$0.840	$0.411	$(1.096)	$(1.096)	-	-	-	**$(0.760)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.392	$2.841	$1.686	-	-	-	-	-	**$6.919**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.392	$2.841	$1.686	-	-	-	-	-	**$6.919**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.797

Risk Tolerance

SAP HANA Database Migration

Report Pulled: 4/23/2025 **Item ID: 11774**

EXECUTIVE SUMMARY

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.
Technology Capability	SAP is eliminating support for all databases other than HANA beginning in 2027. By migrating to HANA in advance of this 2027 date, the Company is able to eliminate its reliance on Oracle's database software and move to SAP's long-term database solution, HANA.

REDACTED

CONFIDENTIAL PROJECT
FILED UNDER SEAL WITH THE EXECUTIVE SECRETARY

SAP Support Pack Upgrade 2023-2024

Report Pulled: 4/23/2025 **Item ID: 12500**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , SAP Support Pack Upgrade 2023, SAP Support Pack Upgrade 2024, SAP Support Pack Upgrade 2023-2024

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 our business partners.

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

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

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), Governance, Risk and Compliance (GRC), 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) Divide 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) Migrate to SAP S/4HANA. This option was not selected at this time because it is part of the long-term digital plan and requires substantial planning and investment, (3) 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
2/1/2024	4/1/2024	6/1/2024	7/1/2024
	In-Service/Go-Live	**Closeout**	
	10/15/2024	10/31/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.010	$0.148	-	-	-	-	-	-	$0.158
Total Cost of Ownership	$0.010	$0.148	-	-	-	-	-	-	**$0.158**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.001	$0.019	-	-	-	-	-	-	**$0.020**
Outside Services	$0.008	$0.129	-	-	-	-	-	-	**$0.137**
Business Expense/Overheads	$0.001	-	-	-	-	-	-	-	**$0.001**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.010	$0.148	-	-	-	-	-	-	**$0.158**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.010	$0.148	-	-	-	-	-	-	**$0.158**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.010	$0.148	-	-	-	-	-	-	**$0.158**
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 and information security related issues by ensuring that all the SAP applications have the latest patches and bug fixes.

SAP Support Pack Upgrade 2026

Report Pulled: 4/23/2025 **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 our business partners.

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

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

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) Divide 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) Migrate 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) 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

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	$1.055	-	-	-	$1.055
Total Cost of Ownership	-	-	-	-	$1.055	-	-	-	**$1.055**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	-	-	-	-	$0.986	-	-	-	**$0.986**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	-	-	-	$0.069	-	-	-	**$0.069**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	-	-	-	$1.055	-	-	-	**$1.055**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	$1.055	-	-	-	**$1.055**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	$1.055	-	-	-	**$1.055**
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
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.

Saviynt Enterprise Identity Governance and Access (EIGA) Report Pulled: 4/23/2025 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 & STAN

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 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.

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	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/1/2024	4/5/2024	6/15/2024	8/1/2024
	In-Service/Go-Live	**Closeout**	
	5/29/2026	6/30/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$2.795	$1.900	$0.947	-	-	-	-	-	$5.641
O&M	$0.236	$0.450	$0.060	$0.765	$0.765	$0.765	-	-	$3.042
Total Cost of Ownership	$3.031	$2.351	$1.007	$0.765	$0.765	$0.765	-	-	**$8.683**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.390	$0.449	$0.198	-	-	-	-	-	**$1.036**
Outside Services	$0.410	$1.100	$0.600	-	-	-	-	-	**$2.110**
Business Expense/Overheads	$0.179	$0.702	$0.159	-	-	-	-	-	**$1.041**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	$0.100	$0.050	-	-	-	-	-	**$0.150**
Licenses, Permits & Fees	$2.051	-	-	-	-	-	-	-	**$2.051**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$3.031	$2.351	$1.007	-	-	-	-	-	**$6.388**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.236	$0.450	$0.060	$0.765	$0.765	$0.765	-	-	**$3.042**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.236	$0.450	$0.060	$0.765	$0.765	$0.765	-	-	**$3.042**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$2.795	$1.900	$0.947	-	-	-	-	-	**$5.641**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$2.795	$1.900	$0.947	-	-	-	-	-	**$5.641**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Security/OT Field Modernization

Report Pulled: 4/23/2025 | 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 & SEI

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 chose to deploy a dedicated OT laptop and communications circuits.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/13/2025	3/7/2025	4/30/2025	5/30/2025
	In-Service/Go-Live	**Closeout**	
	3/1/2026	6/1/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.835	$0.326	-	-	-	-	-	-	$1.162
O&M	$0.243	$0.314	$0.294	$0.294	$0.294	-	-	-	$1.438
Total Cost of Ownership	$1.078	$0.640	$0.294	$0.294	$0.294	-	-	-	**$2.600**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.341	$0.125	-	-	-	-	-	-	**$0.467**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.370	$0.168	-	-	-	-	-	-	**$0.538**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.285	$0.123	-	-	-	-	-	-	**$0.408**
Licenses, Permits & Fees	$0.035	$0.020	-	-	-	-	-	-	**$0.055**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.031	$0.436	-	-	-	-	-	-	**$1.467**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.243	$0.314	$0.294	$0.294	$0.294	-	-	-	**$1.438**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.243	$0.314	$0.294	$0.294	$0.294	-	-	-	**$1.438**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.835	$0.326	-	-	-	-	-	-	**$1.162**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.835	$0.326	-	-	-	-	-	-	**$1.162**
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.

Self Service Vendor Portal

Report Pulled: 4/23/2025 **Item ID: 13942**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Supplier Portal for Invoice Management, Vendor Portal, Self Service Vendor Portal

Description The work will create an external portal for vendors to exercise self-service features to streamline and automate purchase order and invoice management and improve visibility to invoice and payment status.

Portfolio Corporate Services > Financial Services > Controller > General Accounting > * > *

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

WORK OBJECTIVES

Problem Statement

For Accounts Payable, vendors must repeatedly interact with the Company through multiple channels to ask questions, submit invoices, or check invoice or payment status, including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates, to make payments, or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for vendor invoice and payment management and lacks the ability for vendors to utilize touchless invoice creation from POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 6 contracted resources, and creates the potential for late payments or missing early payment discounts. For Supply Chain, vendors must repeatedly interact with the Company through multiple channels to ask questions, update POs (quantities, costs, shipping dates) including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for updates to the POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 4 employee resources. This also creates the potential for late payments, missing early payment discounts, delays in receiving due to lack of shipping notifications from vendors, delays to scheduled work due to lack of acknowledgement and lead time adherence, and the inability to enforce contractual obligations.

Objectives

This project creates value for the Company by: (1) creating self-service functionality/increasing touchless invoice creation/processing that allows the vendor to select items from a purchase order to create an invoice on demand; (2) providing vendors with real-time invoice and payment status, increasing employee productivity by eliminating waste (3) allow self-service updates of vendor master data (banking info, remittance info, etc.) (4) fewer late payments by vendors thus reducing Company follow up and tracking; (5) creating better visibility for vendors to take advantage of early payment discounts thus reducing related vendor inquiries; (6) reducing vendor questions related to invoice and purchase orders through self-service functions and portal information; (7) reducing the cost per invoice; (8) creating self-service functionality/increasing touchless PO creation/processing that allows the vendor to select items from a purchase order to update quantities, costs, and shipping dates; (9) providing vendors with real-time PO information, increasing employee productivity by eliminating waste; and (10) fewer late deliveries by vendors thus reducing Company follow up and tracking.

Scope

The project scope includes: (1) submit an RFP for a vendor portal solution and implementation; (2) configure ability for vendors to more efficiently and more accurately self-submit invoices and POs electronically; (3) configure ability for vendors to self-convert items on a purchase order to an invoice; (4) configure ability for vendors to view invoice and payment status; (5) configure ability for vendors to make changes to SAP master data, including PO line item details; (6) configure ability to offer/process dynamic discounting (7) create new reports and dashboards; (8) enabling method to validate vendors should have access to the portal and removing access when appropriate; (9) configure ability for vendors to make self-serve changes to shipping status and delivery dates; and (10) integration to vendor invoice management system and SAP.

Alternatives

Alternatives considered include: (1) Continue use of the current manual processes which results in waste and inefficiencies for employees and vendors. This could also result in late payments and lost discounts for vendors; (2) Build a custom solution. This option was not selected as the Company has a vendor portal, that is only leveraged for vendors to ask questions. As well, it doesn't leverage best practices; (3) Building a combination of custom and standard integration to existing solutions. This option was not selected because it doesn't follow industry best practices; (4) expand our current vendor portal. This option was not chosen due to limited functionality and not matching capability roadmaps; and (5) implement a new SaaS solution specific to a vendor portal experience. Option (5) is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation to vendors via real-time processing.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
9/1/2025	3/1/2026	5/1/2026	7/1/2026
	In-Service/Go-Live	**Closeout**	
	8/1/2026	8/15/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	$0.135	-	-	-	-	-	$0.135
O&M	-	-	$0.128	$0.575	$0.575	$0.575	-	-	$1.855
Total Cost of Ownership	-	-	$0.263	$0.575	$0.575	$0.575	-	-	**$1.989**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	-	$0.175	$0.032	$0.032	$0.032	-	-	**$0.271**
Outside Services	-	-	$0.080	$0.080	$0.080	$0.080	-	-	**$0.320**
Business Expense/Overheads	-	-	$0.008	$0.008	$0.008	$0.008	-	-	**$0.034**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	$0.450	$0.450	$0.450	-	-	**$1.350**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	-	-	$0.263	$0.570	$0.570	$0.570	-	-	**$1.974**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	$(1.056)	$(1.056)	$(1.056)	$(1.056)	-	-	**$(4.222)**
	Initial	-	-	$0.128	$0.575	$0.575	$0.575	-	-	**$1.855**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	$(0.927)	$(0.480)	$(0.480)	$(0.480)	-	-	**$(2.368)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	$0.135	-	-	-	-	-	**$0.135**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	$0.135	-	-	-	-	-	**$0.135**

Self Service Vendor Portal

Report Pulled: 4/23/2025 **Item ID: 13942**

EXECUTIVE SUMMARY

Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	1.126

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Advanced Shipping Notice - Automated error handling / issue resolution workflow
Risk Mitigation	Advanced Shipping Notice - Automated error handling / issue resolution workflow - reduces incorrect information, introduces better governance over Advanced Shipping Notices
Intangibles	Advanced Shipping Notice - Automated open PO detail listing for notice: PO number, item numbers, item description, price, quantity, delivery date, shipping address - not currently experienced functionality
Risk Mitigation	AP Automation & Reporting - Ability to Assign Dates to Proper Fields (Contract Term Compliance)
Risk Mitigation	AP Automation & Reporting - Accrual Reporting
Intangibles	AP Automation & Reporting - Contract/PO based E-Invoicing via Portal - better decisions with quicker reporting
Intangibles	AP Automation & Reporting - Front End Duplicate & Error Checking - meeting accuracy metrics
Risk Mitigation	AP Automation & Reporting - Invoices are visible & retrievable from within SAP
Intangibles	AP Automation & Reporting - PO Flip: Immediate invoice creation - reduces time and costs per invoice
Intangibles	Automated SAP system update - PO - decreases manual entries/changes
Intangibles	Improved vendor relations due to self-service features: providing real-time and customized invoices and providing visibility for vendor discounts.

Service Restoration Artificial Intelligence

Report Pulled: 4/23/2025 **Item ID: 14031**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , 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	$1.000	$0.476	-	-	-	-	-	-	$1.477
O&M	$0.114	$0.056	-	-	-	-	-	-	$0.170
Total Cost of Ownership	$1.114	$0.532	-	-	-	-	-	-	**$1.647**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.680	$0.380	-	-	-	-	-	-	**$1.060**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.435	$0.152	-	-	-	-	-	-	**$0.587**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.114	$0.532	-	-	-	-	-	-	**$1.647**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.114	$0.056	-	-	-	-	-	-	**$0.170**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.114	$0.056	-	-	-	-	-	-	**$0.170**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.000	$0.476	-	-	-	-	-	-	**$1.477**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.000	$0.476	-	-	-	-	-	-	**$1.477**
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: 4/23/2025 **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 (IaaS); (3) implementing scale sets 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	$0.116	-	-	-	-	-	-	-	$0.116
O&M	$0.245	-	-	-	-	-	-	-	$0.245
Total Cost of Ownership	$0.361	-	-	-	-	-	-	-	**$0.361**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.305	-	-	-	-	-	-	-	**$0.305**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.056	-	-	-	-	-	-	-	**$0.056**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.361	-	-	-	-	-	-	-	**$0.361**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.245	-	-	-	-	-	-	-	**$0.245**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.245	-	-	-	-	-	-	-	**$0.245**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.116	-	-	-	-	-	-	-	**$0.116**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.116	-	-	-	-	-	-	-	**$0.116**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

SiteCore Primary Upgrade 2025 *EXECUTIVE SUMMARY*	**Report Pulled: 4/23/2025**	**Item ID: 12727**
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: 4/23/2025 **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 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) Migrate to a cloud solution. This alternative was not chosen due to the cost/benefit analysis of re-architecting our current Sitecore implementation to facilitate cloud migration is not 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
1/18/2027	3/22/2027	4/5/2027	9/30/2027
	In-Service/Go-Live	**Closeout**	
	10/1/2027	10/15/2027	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	-	-	$0.104	-	-	-	-	-	$0.104
Total Cost of Ownership	-	-	$0.104	-	-	-	-	-	**$0.104**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	-	$0.097	-	-	-	-	-	**$0.097**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	-	$0.007	-	-	-	-	-	**$0.007**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	-	$0.104	-	-	-	-	-	**$0.104**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	$0.104	-	-	-	-	-	**$0.104**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	$0.104	-	-	-	-	-	**$0.104**
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.

Software Asset - Service Management Upgrade

Report Pulled: 4/23/2025 **Item ID: 13928**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias , Software Asset - Service Management Upgrade

Description This project will optimize the software asset management process by systematically monitor, assess and oversee software licenses and compliance using Software Asset Management Professional.

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

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

WORK OBJECTIVES

Problem Statement The on-premises software asset management technology currently used in the Company lacks compatibility to automate license reclamation, cost optimization, and license forecasting. These software asset management constraints lead to the inability to optimize software license purchasing and effective license demand management.

Objectives This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective software asset management processes and workflow. Specifically, by replacing the on-premise application, the project will: (1) streamline the software request workflow including license reclamation and software deployment; (2) help ensure compliance with software license agreements; (3) identify opportunities of license optimization leading to cost optimization; (4) mitigate risk related to software asset management; (5) optimize license forecasting and (6) increase asset visibility.

Scope The project scope includes: (1) the implementation of software asset management tool; (2) the establishment of process and process roles needed to support the assets; and (3) retirement of the on-premise software asset management tool.

Alternatives Alternatives considered included: (1) Choose an alternate Cloud based asset management system. This alternative was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not selected as the current Software Asset Management tool that lacks integration and automation and will not address optimizing and effective management of licenses and purchases. (4) Develop and implement an on-premises Software Asset Management solution. This alternative ultimately chosen has strengths in software asset management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can helps license compliance, optimization and automation.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
6/1/2023	9/1/2023	9/30/2023	10/1/2023
	In-Service/Go-Live	**Closeout**	
	2/29/2024	3/15/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.050	$0.070	-	-	-	-	-	-	$1.120
O&M	$0.180	$0.080	$0.005	$0.005	$0.005	$0.005	-	-	$0.280
Total Cost of Ownership	$1.230	$0.150	$0.005	$0.005	$0.005	$0.005	-	-	**$1.401**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.074	$0.060	-	-	-	-	-	-	**$0.134**
Outside Services	$0.331	$0.086	-	-	-	-	-	-	**$0.416**
Business Expense/Overheads	$0.029	$0.005	-	-	-	-	-	-	**$0.034**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.796	-	-	-	-	-	-	-	**$0.796**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.230	$0.150	-	-	-	-	-	-	**$1.381**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	$(0.180)	$(0.064)	-	-	-	-	-	**$(0.244)**
	Initial	$0.180	$0.080	$0.005	$0.005	$0.005	$0.005	-	-	**$0.280**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.180	$(0.100)	$(0.059)	$0.005	$0.005	$0.005	-	-	**$0.036**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.050	$0.070	-	-	-	-	-	-	**$1.120**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.050	$0.070	-	-	-	-	-	-	**$1.120**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.803

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Software Asset - Service Management Upgrade

Report Pulled: 4/23/2025 **Item ID: 13928**

EXECUTIVE SUMMARY

OTHER VALUE

Type	Description
Avoided Costs	Avoided cost by having automation built to reclaim licenses when a resource leaves the Company. SAM Pro will serve as the new Software Asset Management system of record, resulting in an annual cost savings of $66,000 and providing a single source to manage and request software and hardware. The cost savings here is from the 0.5 FTE HCL resource ($43,500) and 0.25 FTE CE resource ($22,500) that are not needed to manually maintain this process.
Technology Capability	By replacing the on-premise infrastructure with a Cloud Based System aligns with the Company goal of moving to the Cloud for better scalability and flexibility. This capability will help mitigate the labor of maintaining the current on-premise infrastructure with patching.
Technology Capability	SAM Pro provides the capability for better Automation on Software requests. With SNOW when a user requests for new Software, it took some time to check for the license availability and fulfill the request, but with SAM Pro the check happens real time and the latest version is procured. Governance improvements were made by adding extra checks in the workflow for EA (enterprise Architecture) and Cyber Security to do a high level review of the Software being requested to address any concerns early on.
Technology Capability	With the implementation of SAM Pro, there is no longer the need to sync up the software versions on 2 different systems (ServiceNow and SNOW) along with keeping the Product Owners and Technical Owners in sync for the software. SAM Pro also ensures that the SCCM ID has the latest version of the software to be pushed over to the user PC's when requested.

Software Platform Refresh

Report Pulled: 4/23/2025 **Item ID: 6843**

EXECUTIVE SUMMARY

BASIC INFORMATION

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

Alias Software Platform Refresh

Description The Software Platform Refresh project will upgrade server operating systems, hypervisors, databases and infrastructure platforms to retain low-cost vendor support.

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

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

WORK OBJECTIVES

Problem Statement For systems that go beyond their normal manufacturer support ending, there will be increased support and maintenance fees of 20% to 100% above current support and maintenance depending on vendor. Completing this project allows the organization to (1) avoid high support costs; (2) provide for system security; and (3) stay current to promote seamless interoperability among servers, applications, and databases. Aging platforms are more susceptible to security vulnerabilities and performance issues that ultimately could affect the business and customers.

Objectives The project will add value for the Company by: (1) avoiding costs for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring reliability and compliance with Information Security requirements; (3) improving data center environment stability; and (4) avoiding the need for high risk upgrades that cross multiple versions.

Scope The project scope includes: (1) upgrading operating systems and databases on servers that are near end of support with a given vendor; and (2) maintaining hypervisors and infrastructure platforms at the current version for stability and performance.

Alternatives A funding options matrix was completed to review the potential alternatives. The alternatives identified were: (1) Complete the full scope of the solution for $1 million in order to eliminate the need for ongoing extended support; (2) Reduce the scale of the solution, which requires $1.6 million in ongoing extended support; (3) Reduce the scale of the solution even further, which requires $2.4 million in ongoing extended support; (4) Do not complete a software platform refresh, which requires $3.3 million in ongoing extended support. Alternative 1 was selected as the most cost effective solution to ensure ongoing system stability; seamless integration; and mitigation of cyber-security risks without the significant cost of extended support necessary for end of life software systems.

DATES (phase end)

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

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

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.137	$0.088	$0.113	-	-	-	-	-	$0.338
Total Cost of Ownership	$0.137	$0.088	$0.113	-	-	-	-	-	**$0.338**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.088	$0.021	$0.105	-	-	-	-	-	**$0.214**
Outside Services	$0.041	$0.010	-	-	-	-	-	-	**$0.052**
Business Expense/Overheads	$0.008	-	$0.007	-	-	-	-	-	**$0.015**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.057	-	-	-	-	-	-	**$0.057**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.137	$0.088	$0.113	-	-	-	-	-	**$0.338**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.137	$0.088	$0.113	-	-	-	-	-	**$0.338**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.137	$0.088	$0.113	-	-	-	-	-	**$0.338**
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	There is a high risk of technology obsolescence that would result in a high impact to business and customer service operations. To mitigate this risk Consumers Energy can choose to pay significantly more for extended maintenance or complete the project with increased functionality at a lower cost.

OTHER VALUE

Type	Description
Avoided Costs	Consumers Energy has 1,112 instances of operating systems, databases, and hypervisors that will require special maintenance contracts by January of 2020. Microsoft has identified additional maintenance costs of $705 per Central Processing Unit (CPU) Core running Windows 2008 starting in January of 2020. Consumers Energy has 4,718 CPU Cores running in the Windows 2008 environment for a total of $3,326,190 in additional maintenance charges.
Risk Mitigation	This project addresses the problem of new security vulnerabilities that would not be patched under extended maintenance.
Risk Mitigation	Through this project, Consumers Energy will be able to proactively patch systems to avoid bugs and stay current to promote seamless interoperability among servers.

Spatial Asset Management

Report Pulled: 4/23/2025 **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	12/31/2024	10/31/2025
	In-Service/Go-Live	**Closeout**	
	11/1/2025	11/30/2025	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.436	$0.739	$0.714	-	-	-	-	-	$2.889
O&M	-	$0.019	$0.279	$0.172	$0.172	$0.172	$0.172	-	$0.986
Total Cost of Ownership	$1.436	$0.758	$0.993	$0.172	$0.172	$0.172	$0.172	-	**$3.875**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	$0.052	$0.240	-	-	-	-	-	**$0.292**
Outside Services	$0.160	$0.351	$0.420	-	-	-	-	-	**$0.931**
Business Expense/Overheads	$0.100	$0.121	$0.161	-	-	-	-	-	**$0.382**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	$1.176	$0.233	-	-	-	-	-	-	**$1.409**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$1.436	$0.758	$0.821	-	-	-	-	-	**$3.014**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.019	$0.279	$0.172	$0.172	$0.172	$0.172	-	**$0.986**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.019	$0.279	$0.172	$0.172	$0.172	$0.172	-	**$0.986**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$1.436	$0.739	$0.714	-	-	-	-	-	**$2.889**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.436	$0.739	$0.714	-	-	-	-	-	**$2.889**
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: 4/23/2025 **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

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.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/3/2025	3/3/2025	4/7/2025	8/7/2025
	In-Service/Go-Live	**Closeout**	
	8/14/2025	8/28/2025	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$1.785	-	-	-	-	-	-	-	$1.785
O&M	$0.269	$0.030	$0.030	-	-	-	-	-	$0.330
Total Cost of Ownership	$2.054	$0.030	$0.030	-	-	-	-	-	**$2.115**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$1.110	-	-	-	-	-	-	-	**$1.110**
Outside Services	$0.400	-	-	-	-	-	-	-	**$0.400**
Business Expense/Overheads	$0.514	-	-	-	-	-	-	-	**$0.514**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$2.024	-	-	-	-	-	-	-	**$2.024**

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	$0.269	$0.030	$0.030	-	-	-	-	-	**$0.330**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.269	$0.022	$0.022	$(0.009)	-	-	-	-	**$0.304**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$1.785	-	-	-	-	-	-	-	**$1.785**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$1.785	-	-	-	-	-	-	-	**$1.785**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall)	-0.990

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Streetlight Outage and Restoration Optimization

Report Pulled: 4/23/2025 **Item ID: 13926**

EXECUTIVE SUMMARY

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: 4/23/2025 | 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 Company strategies.

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-boarding through Off-boarding; (3) Succession Planning and Business Continuity; (4) Career Development and Employee Retention.

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	$0.551	-	-	-	-	-	$0.833
O&M	$0.204	$0.180	$0.096	$0.100	$0.100	-	-	-	$0.680
Total Cost of Ownership	$0.433	$0.233	$0.647	$0.100	$0.100	-	-	-	**$1.513**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.020	$0.007	$0.225	-	-	-	-	-	**$0.252**
Outside Services	$0.388	$0.225	$0.285	-	-	-	-	-	**$0.898**
Business Expense/Overheads	$0.026	$0.000	$0.137	-	-	-	-	-	**$0.163**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.433	$0.233	$0.647	-	-	-	-	-	**$1.313**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.204	$0.180	$0.096	$0.100	$0.100	-	-	-	**$0.680**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.204	$0.180	$0.096	$0.100	$0.100	-	-	-	**$0.680**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.229	$0.052	$0.551	-	-	-	-	-	**$0.833**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.229	$0.052	$0.551	-	-	-	-	-	**$0.833**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-

Talent Management Enablement

Report Pulled: 4/23/2025 **Item ID: 11828**

EXECUTIVE SUMMARY

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 faciliate 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: 4/23/2025 **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 & SEI

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

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	$0.162	-	-	-	-	-	-	$0.162
O&M	-	$0.110	-	-	-	-	-	-	$0.110
Total Cost of Ownership	-	$0.272	-	-	-	-	-	-	**$0.272**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	$0.133	-	-	-	-	-	-	**$0.133**
Outside Services	-	$0.139	-	-	-	-	-	-	**$0.139**
Business Expense/Overheads	-	-	-	-	-	-	-	-	-
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.272	-	-	-	-	-	-	**$0.272**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.110	-	-	-	-	-	-	**$0.110**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.110	-	-	-	-	-	-	**$0.110**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.162	-	-	-	-	-	-	**$0.162**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.162	-	-	-	-	-	-	**$0.162**
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: 4/23/2025 **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
2/1/2025	2/28/2025	3/31/2025	10/31/2025
	In-Service/Go-Live	**Closeout**	
	11/1/2025	11/17/2025	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$0.960	-	-	-	-	-	-	$0.960
O&M	-	$0.065	$0.070	$0.074	$0.077	$0.081	-	-	$0.366
Total Cost of Ownership	-	$1.024	$0.070	$0.074	$0.077	$0.081	-	-	**$1.326**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.166	-	-	-	-	-	-	**$0.166**
Outside Services	-	$0.578	-	-	-	-	-	-	**$0.578**
Business Expense/Overheads	-	$0.100	-	-	-	-	-	-	**$0.100**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.180	-	-	-	-	-	-	**$0.180**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$1.024	-	-	-	-	-	-	**$1.024**

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	-	$0.065	$0.070	$0.074	$0.077	$0.081	-	-	**$0.366**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$(0.015)	$0.050	$0.055	$0.059	$0.062	$0.081	-	-	**$0.291**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.960	-	-	-	-	-	-	**$0.960**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.960	-	-	-	-	-	-	**$0.960**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.951

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Transmission Outage Application (TOA) Upgrade

Report Pulled: 4/23/2025 **Item ID: 12481**

EXECUTIVE SUMMARY

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.

Work Management Scheduling Analytics and Reporting

Report Pulled: 4/23/2025 **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	-	-	-	-	-	$1.880
O&M	$0.071	$0.046	$0.047	$0.075	$0.075	$0.075	$0.075	-	$0.464
Total Cost of Ownership	$0.896	$0.998	$0.150	$0.075	$0.075	$0.075	$0.075	-	**$2.344**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	$0.122	$0.195	$0.038	-	-	-	-	-	**$0.355**
Outside Services	$0.678	$0.630	$0.052	-	-	-	-	-	**$1.360**
Business Expense/Overheads	$0.088	$0.141	$0.013	-	-	-	-	-	**$0.241**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.000	$0.019	-	-	-	-	-	**$0.020**
Licenses, Permits & Fees	$0.009	$0.032	$0.027	-	-	-	-	-	**$0.068**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.896	$0.998	$0.150	-	-	-	-	-	**$2.044**

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	$0.075	$0.075	$0.075	$0.075	-	**$0.464**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.071	$0.001	$(0.007)	$0.021	$0.021	$0.021	$0.021	-	**$0.150**
Cap+COR	Reduction	-	$(0.159)	$(0.191)	$(0.191)	$(0.191)	$(0.191)	$(0.191)	-	**$(1.113)**
	Initial	$0.825	$0.952	$0.103	-	-	-	-	-	**$1.880**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.825	$0.793	$(0.087)	$(0.191)	$(0.191)	$(0.191)	$(0.191)	-	**$0.768**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.494

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

Work Management Scheduling Analytics and Reporting

Report Pulled: 4/23/2025 **Item ID: 6811**

EXECUTIVE SUMMARY

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.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Electric and Common Capital Expenditures
For the Projected Year 2025, 2026, and Test Year Ending April 30, 2027
For the Historical Year 2024

Case No.: U-21870
Exhibit No.: A-22 (SHB-7)
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Date: June 2025

ARP-Collaboration

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Conference room refresh	$150,000	2	1	$300,000	$150,000	$250,000	$171,425
2	Conference room refresh - Small	$15,000	2	1	$30,000	$15,000	$25,000	$17,143
3	Conference room refresh -Large	$50,000	2	1	$100,000	$50,000	$83,333	$57,142
4	Digital Signage refresh - LCD Displays	$1,054	15	16	$15,810	$16,864	$16,161	$11,082
5	Microsoft Teams Rooms	$10,000	11	11	$110,000	$110,000	$110,000	$75,427
6	Oracle (SBC) Session Border Controls	$150,000	0	4	$0	$600,000	$200,000	$137,140
7	Standalone Hub Mics	$2,800	36	36	$100,800	$100,800	$100,800	$69,119
8	Surface Hub 85"	$28,140	10	7	$281,400	$196,980	$253,260	$173,660
9	Surface Hubs 50"	$13,340	10	6	$133,400	$80,040	$115,613	$79,276
10	Verint Servers/Software	$418,260	1	0	$418,260	$0	$278,840	$191,201
11	VGA equipment with HDMI	$2,000	1	0	$2,000	$0	$1,333	$914
12	Software, labor, contractor and overhead and other costs				$263,662	$215,299	$247,541	$169,739
13	**Total Electric Allocation**				$1,755,332	$1,534,983	**$1,681,882**	**$1,153,267**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
14	49" Display Monitor	$2,027	1	0	$2,027	$0	$1,412	$0
15	55' LED Public Display Monitor	$1,051	1	0	$1,051	$0	$732	$0
16	55" LED Display	$1,336	1	0	$1,336	$0	$931	$0
17	Cisco Analog Gateways	$2,800	0	36	$0	$100,800	$0	$69,119
18	Conference room refresh	$150,000	0	3	$0	$450,000	$0	$308,565
19	Conference room refresh - Small	$15,000	0	2	$0	$30,000	$0	$20,571
20	Conference room refresh -Large	$50,000	0	1	$0	$50,000	$0	$34,285
21	Digital Signage	$1,749	1	0	$1,749	$0	$1,218	$0
22	Digital Signage Monitor	$768	1	0	$768	$0	$535	$0
23	Digital Signage refresh - LCD Displays	$1,054	0	14	$0	$14,756	$0	$10,118
24	Digital Signage Replacement	$2,027	1	0	$2,027	$0	$1,412	$0
25	Display	$931	1	0	$931	$0	$649	$0
26	Display	$1,383	1	0	$1,383	$0	$963	$0
27	Display	$2,906	1	0	$2,906	$0	$2,024	$0
28	Display replacement	$1,290	1	0	$1,290	$0	$899	$0
29	Display Replacement	$3,305	1	0	$3,305	$0	$2,302	$0
30	Display Replacement	$1,212	1	0	$1,212	$0	$844	$0
31	Display Replacement	$1,617	1	0	$1,617	$0	$1,126	$0
32	Display Replacement - 49" TV	$1,118	1	0	$1,118	$0	$779	$0
33	Display replacement with cart 32"	$1,361	1	0	$1,361	$0	$948	$0
34	LCD Projector	$2,695	1	0	$2,695	$0	$1,877	$0
35	LED Commercial TV	$1,447	1	0	$1,447	$0	$1,008	$0
36	Microsoft Surface Hub	$11,093	1	0	$11,093	$0	$7,726	$0
37	Microsoft Teams Room	$5,718	1	0	$5,718	$0	$3,983	$0
38	Microsoft Teams Room	$6,303	1	0	$6,303	$0	$4,390	$0
39	Microsoft Teams Room	$6,603	16	0	$105,648	$0	$73,584	$0
40	Microsoft Teams Room	$6,322	1	0	$6,322	$0	$4,403	$0
41	Microsoft Teams Room	$6,647	1	0	$6,647	$0	$4,630	$0
42	Microsoft Teams Room	$6,365	1	0	$6,365	$0	$4,433	$0
43	Microsoft Teams Room	$6,148	1	0	$6,148	$0	$4,282	$0
44	Microsoft Teams Room	$10,000	0	2	$0	$20,000	$0	$13,714
45	Monitor Replacement	$940	1	0	$940	$0	$655	$0
46	Projector replacement	$3,644	1	0	$3,644	$0	$2,538	$0
47	Projector Replacement	$11,163	1	0	$11,163	$0	$7,775	$0
48	Projector Replacement	$2,243	1	0	$2,243	$0	$1,562	$0
49	Rally Room Audio	$25,949	1	0	$25,949	$0	$18,073	$0
50	Rally Room Audio	$10,000	0	6	$0	$60,000	$0	$41,142
51	Simulator Room Monitors	$1,781	1	0	$1,781	$0	$1,241	$0
52	Surface Hub	$10,819	1	0	$10,819	$0	$7,535	$0
53	Surface Hub 85"	$21,539	1	0	$21,539	$0	$15,002	$0
54	Surface Hub 85"	$27,300	0	7	$0	$191,100	$0	$131,037
55	Surface Hub Mics	$10,819	1	0	$10,819	$0	$7,536	$0
56	Surface Hub Replacements	$30,105	11	0	$331,150	$0	$230,646	$0
57	Surface Hub Replacements	$35,327	1	0	$35,327	$0	$24,605	$0
58	Surface Hub Stand	$2,676	1	0	$2,676	$0	$1,864	$0
59	Surface Hub Stand	$2,699	9	0	$24,291	$0	$16,919	$0
60	Surface Hubs 50"	$12,500	0	10	$0	$125,000	$0	$85,713
61	Surface Hubs and Stands	$33,385	1	0	$33,385	$0	$23,253	$0
62	VGA equipment with HDMI	$2,000	0	1	$0	$2,000	$0	$1,371
63	Software, labor, contractor and overhead and other costs				$417,365	$142,179	$290,694	$97,492
64	**Total Electric Allocation**				$1,115,559	$1,185,835	**$776,987**	**$813,127**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Electric and Common Capital Expenditures
For the Projected Year 2025, 2026, and Test Year Ending April 30, 2027
For the Historical Year 2024

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ARP-Cyber Security

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
1	Active Fiber Cable	$511	2	0	$1,021	$0	$548	$0
2	Badge Printer Replacement	$1,953	4	0	$7,810	$0	$4,187	$0
3	Hardware Replacement	$3,186	1	0	$3,186	$0	$1,708	$0
4	Multimode SR	$302	104	0	$31,393	$0	$16,830	$0
5	Networks	$1,193	46	0	$54,886	$0	$29,424	$0
6	Networks	$143	46	0	$6,565	$0	$3,519	$0
7	Networks	$200	46	0	$9,208	$0	$4,936	$0
8	Networks	$4,722	2	0	$9,445	$0	$5,063	$0
9	Networks	$164	46	0	$7,550	$0	$4,048	$0
10	Palo Alto Firewalls 820 Replacement PA-455	$3,703	46	0	$170,354	$0	$91,327	$0
11	QRadar	$18,201	1	0	$18,201	$0	$9,758	$0
12	Software, labor, contractor and overhead and other costs				$125,537	$0	$67,300	$0
13	**Total Electric Allocation**				$445,156	$0	**$238,648**	**$0**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Electric and Common Capital Expenditures
For the Projected Year 2025, 2026, and Test Year Ending April 30, 2027
For the Historical Year 2024

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Witness: SHBaker
Date: June 2025

ARP-Cyber-Common

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Cisco ASA 5516-X to FPR-1120	$3,000	4	0	$12,000	$0	$8,000	$4,142
2	Cisco ASA 5545-X to FPR-1140	$4,000	28	0	$112,000	$0	$74,667	$38,655
3	Cisco ASA 5555-X to FPR-1150	$8,000	4	0	$32,000	$0	$21,333	$11,044
4	Cisco FTD-2110 to FTD-3105	$16,000	0	6	$0	$96,000	$32,000	$16,566
5	Cisco ISE Model number SNS-3695-K9 to SNS-3795-K9	$90,000	0	2	$0	$180,000	$60,000	$31,062
6	F5 BIG-IP i2800 to F5-BIG-DNS-r2800	$40,000	2	2	$80,000	$80,000	$80,000	$41,416
7	F5 BIG-IP i4600 to F5-BIG-DNS-r4600	$50,000	2	0	$100,000	$0	$66,667	$34,513
8	F5 BIG-IP i4800 to F5-BIG-DNS-r4800	$60,000	1	0	$60,000	$0	$40,000	$20,708
9	F5 BIG-IP i5800 to F5-BIG-DNS-r5800	$101,000	7	0	$707,000	$0	$471,333	$244,009
10	Palo Alto Firewall PA-3120Replacement PA-3400	$35,000	7	0	$245,000	$0	$163,333	$84,558
11	Palo Alto Firewall PA-5260Replacement PA-5410	$62,000	4	16	$248,000	$992,000	$496,000	$256,779
12	Software, labor, contractor and overhead and other costs				$123,036	$103,918	$116,663	$60,396
13	**Total Electric Allocation**				$1,719,036	$1,451,918	**$1,629,996**	**$843,849**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
14	Palo Alto Power Adaptor	$271	0	92	$0	$24,932	$0	$12,907
15	QRadar	$54,632	0	4	$0	$218,528	$0	$113,132
16	Software, labor, contractor and overhead and other costs					$39,690	$0	$20,548
17	**Total Electric Allocation**				$0	$283,150	**$0**	**$146,587**

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ARP-Cyber-Electric

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Cisco FTD-2110 to FTD-3105	$16,000	0	26	$0	$416,000	$138,667	$138,667
2	Palo Alto Firewalls 3120 Replacement PA-3400	$35,000	7	0	$245,000	$0	$163,333	$163,333
3	Palo Alto Firewalls 820 Replacement PA-455	$9,500	13	0	$123,500	$0	$82,333	$82,333
4	Software, labor, contractor and overhead and other costs				$44,147	$49,580	$45,958	$45,958
5	**Total Electric Allocation**				$412,647	$465,580	**$430,291**	**$430,291**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
6	OT Firewalls	$66,968	0	1	$0	$66,968	$0	$66,968
7	Software, labor, contractor and overhead and other costs					$7,897	$0	$7,897
8	**Total Electric Allocation**				$0	$74,865	**$0**	**$74,865**

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ARP-Field Device Asset Mgmt

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
	Replacements							
1	Field Devices CF33 w/acce	$4,883	1289	922	$6,294,264	$4,502,181	$5,696,903	$3,906,366
2	Field Devices CF55 w/acces	$4,003	49	50	$196,160	$200,163	$197,494	$135,422
	New Purchases							
3	Field Devices and Accessories				$1,000,000	$1,000,000	$1,000,000	$685,700
4	Software, labor, contractor and overhead and other costs				$197,568	$142,884	$179,340	$122,973
5	**Total Electric Allocation**				$7,687,992	$5,845,228	**$7,073,737**	**$4,850,461**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
	Replacements							
6	Field Devices CF33 w/accessories	$4,909	552	0	$2,709,520	$0	$1,887,180	$0
7	Field Devices CF33	$4,883	0	255	$0	$1,245,180	$0	$853,820
8	Field Devices CF55 w/accessories	$3,652	80	0	$292,161	$0	$203,490	$0
9	Field Devices CF55 w/accessories	$4,003	0	225	$0	$900,734	$0	$617,633
10	Field Devices Getac A140	$4,621	30	0	$138,616	$0	$96,546	$0
11	CF33 accessories				$0	$23,043	$0	$15,801
	New Purchases							
12	Field Devices CF33	$4,909	109	0	$535,032	$0	$372,650	$0
13	Field Devices CF33	$3,598	0	0	$0	$0	$0	$0
14	Field Devices FZ55	$3,652	20	0	$73,040	$0	$50,872	$0
15	Field Devices FZ55	$3,087	0	0	$0	$0	$0	$0
16	Field Devices Getac A140	$4,621	20	0	$92,411	$0	$64,364	$0
17	Field Devices and Accessories				$0	$1,000,000	$0	$685,700
18	Accessories				$1,201	$0	$836	$0
19	Software, labor, contractor and overhead and other costs				$111,010	$80,556	$77,319	$55,237
20	**Total Electric Allocation**				$3,952,991	$3,249,513	**$2,753,258**	**$2,228,191**

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ARP-Local Area Network

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	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
1	Cisco C9120AXI-B	$1,839	395	0	$726,591	$0	$389,525	$0
2	Cisco C9130AXI-B	$3,037	161	0	$488,920	$0	$262,110	$0
3	Cisco N9K-C9364C	$45,253	3	0	$135,759	$0	$72,780	$0
4	Fiber Optic Cables	$2,374	5	0	$11,870	$0	$6,364	$0
5	Juniper EX4100-48MP	$8,573	23	0	$197,176	$0	$105,706	$0
6	Juniper EX4400-48F	$20,419	1	0	$20,419	$0	$10,947	$0
7	Juniper Power Supply JPSU-920-AC-AFO	$386	55	0	$21,205	$0	$11,368	$0
8	MX204-HW-BASE	$44,409	3	0	$133,227	$0	$71,423	$0
9	Software, labor, contractor and overhead and other costs				$1,311,162	$0	$702,914	$0
10	**Total Electric Allocation**				$3,046,329	$0	**$1,633,137**	**$0**

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ARP-Network-Common

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Cisco 8500	$34,129	0	7	$0	$238,903	$79,634	$41,227
2	Cisco APIC-CLUSTER-M3	$22,780	0	9	$0	$205,020	$68,340	$35,380
3	Cisco N9K-C9364C	$20,932	0	4	$0	$83,729	$27,910	$14,449
4	Cisco SE-CL-L3	$58,194	0	4	$0	$232,775	$77,592	$40,169
5	Datacom Line Tap	$3,887	5	5	$19,435	$19,435	$19,435	$10,061
6	Hirschmann BRS-32 Field Switch 942170999-21510232575	$3,939	0	10	$0	$39,390	$13,130	$6,797
7	Hirschmann Fiber Optic	$198	0	10	$0	$1,980	$660	$342
8	Hirschmann RJ45 SFP	$447	0	10	$0	$4,470	$1,490	$771
9	Juniper EX4100-48MP	$3,396	6	0	$20,378	$0	$13,586	$7,033
10	Juniper EX4600-40F	$8,865	25	28	$221,625	$248,220	$230,490	$119,325
11	Juniper EX4650-48Y	$12,625	35	22	$441,875	$277,750	$387,167	$200,436
12	Juniper QFX5120-48T	$12,376	5	5	$61,880	$61,880	$61,880	$32,035
13	Software, labor, contractor and overhead and other costs				$68,475	$101,641	$79,530	$41,173
14	**Total Electric Allocation**				$833,668	$1,515,192	**$1,060,843**	**$549,198**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
15	Infoblox CP-V805 Azure Lab Nodes	$23,746	0	2	$0	$47,492	$0	$24,587
16	Infoblox IB-VM-1420	$18,962	0	1	$0	$18,962	$0	$9,817
17	Infoblox Trinzic TE-1415	$43,749	0	10	$0	$437,492	$0	$226,490
18	Infoblox Trinzic TE-1425	$63,412	0	3	$0	$190,236	$0	$98,485
19	Infoblox Trinzic TE-825	$18,436	0	5	$0	$92,180	$0	$47,722
20	Infoblox V1405 - Azure Prod Nodes	$42,731	0	2	$0	$85,462	$0	$44,244
21	Invoblox IB-V5005	$22,839	0	1	$0	$22,839	$0	$11,824
22	Juniper EX4100-24MP	$6,743	0	4	$0	$26,971	$0	$13,963
23	Juniper EX4100-48MP	$8,132	0	7	$0	$56,924	$0	$29,469
24	Juniper EX4100-F-12P	$1,290	0	5	$0	$6,448	$0	$3,338
25	Juniper EX4300-48P	$5,631	0	4	$0	$22,523	$0	$11,660
26	Juniper EX4400-48F	$12,270	0	4	$0	$49,081	$0	$25,409
27	Juniper Power Supply JPSU-920-AC-AFO	$996	0	5	$0	$4,980	$0	$2,578
28	Juniper QFX5120-48T	$20,512	0	2	$0	$41,024	$0	$21,238
29	Software, labor, contractor and overhead and other costs				$0	$178,985	$0	$92,661
30	**Total Electric Allocation**				$0	$1,281,598	**$0**	**$663,483**

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ARP-Network-Electric

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Datacom Line Tap	$3,887	15	5	$58,305	$19,435	$45,348	$45,348
2	Software, labor, contractor and overhead and other costs				$8,063	$2,721	$6,282	$6,282
3	**Total Electric Allocation**				$66,368	$22,156	**$51,630**	**$51,630**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
4	Cisco C9120AXI-B	$1,052	0	2	$0	$2,103	$0	$2,103
5	Cisco C9130AXI-B	$1,474	0	4	$0	$5,896	$0	$5,896
6	Connected Grid Routers	$55,224	0	1	$0	$55,224	$0	$55,224
7	Connected Grid Switches	$96,642	0	1	$0	$96,642	$0	$96,642
8	Firewalls	$66,968	0	1	$0	$66,968	$0	$66,968
9	ISR/ASR Routers	$25,845	0	1	$0	$25,845	$0	$25,845
10	Switches	$135,251	0	1	$0	$135,251	$0	$135,251
11	Software, labor, contractor and overhead and other costs				$0	$36,924	$0	$36,924
12	**Total Electric Allocation**				$0	$424,853	**$0**	**$424,853**

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ARP-OT Support-Common

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Hypervisor VMWare	$83,104	0	2	$0	$166,208	$55,403	$37,990
2	Server Small	$10,609	0	1	$0	$10,609	$3,536	$2,425
3	Software, labor, contractor and overhead and other costs				$0	$9,750	$3,250	$2,229
4	**Total Electric Allocation**				$0	$186,567	**$62,189**	**$42,643**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
5	Hypervisor Nutanix	$61,667	0	4	$0	$246,667	$0	$169,139
6	Software, labor, contractor and overhead and other costs				$0	$13,000	$0	$8,914
7	**Total Electric Allocation**				$0	$259,667	**$0**	**$178,053**

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ARP-OT Support-Electric

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Hypervisor Nutanix	$63,517	3	0	$190,550	$0	$127,033	$127,033
2	Hypervisor Nutanix	$65,422	0	11	$0	$719,644	$239,881	$239,881
3	Server Large	$18,540	32	0	$593,280	$0	$395,520	$395,520
4	Server Large	$19,096	0	6	$0	$114,577	$38,192	$38,192
5	Server Small	$10,300	20	0	$206,000	$0	$137,333	$137,333
6	Server Small	$10,609	0	2	$0	$21,218	$7,073	$7,073
7	Software, labor, contractor and overhead and other costs				$178,750	$61,750	$139,750	$139,750
8	**Total Electric Allocation**				$1,168,580	$917,189	**$1,084,783**	**$1,084,783**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
9	ASA To FTD	$44,870	27	0	$1,211,480	$0	$1,211,480	$0
10	Cisco C8500	$73,353	1	0	$73,353	$0	$73,353	$0
11	Cisco Catalyst	$13,250	1	0	$13,250	$0	$13,250	$0
12	DataCom Tap	$8,258	3	0	$24,773	$0	$24,773	$0
13	F5 Appliances	$19,604	7	0	$137,229	$0	$137,229	$0
14	FPR 3140	$47,452	2	0	$94,904	$0	$94,904	$0
15	GPS Clocks	$4,939	2	0	$9,878	$0	$9,878	$0
16	Hard drive Enclosures	$2,275	6	0	$13,650	$0	$13,650	$0
17	Juniper Switches	$25,907	1	0	$25,907	$0	$25,907	$0
18	Juniper Switches for backup	$27,823	12	0	$333,876	$0	$333,876	$0
19	Server Large	$18,000	0	2	$0	$36,000	$0	$36,000
20	Server Small	$10,000	0	1	$0	$10,000	$0	$10,000
21	VxRail NICs	$153	60	0	$9,180	$0	$9,180	$0
22	Software, labor, contractor and overhead and other costs				$297,246	$9,750	$297,246	$9,750
23	**Total Electric Allocation**				$2,244,726	$55,750	**$2,244,726**	**$55,750**

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ARP-Physical Security

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Cabling/Misc Equipment	$10,000	13	13	$130,000	$130,000	$130,000	$89,141
2	Cameras	$3,500	163	0	$570,500	$0	$380,333	$260,795
3	Cameras	$3,575	0	160	$0	$572,000	$190,667	$130,740
4	Lift Charge	$5,000	13	13	$65,000	$65,000	$65,000	$44,571
5	Logistics & Operation Expense	$4,000	13	13	$52,000	$52,000	$52,000	$35,656
6	NVR/Monitor	$37,000	13	13	$481,000	$481,000	$481,000	$329,822
7	Software, labor, contractor and overhead and other costs				$814,320	$814,320	$814,320	$558,379
8	**Total Electric Allocation**				$2,112,820	$2,114,320	**$2,113,320**	**$1,449,104**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
9	3rd Party Vendor	$41,325	2	0	$82,650	$0	$57,566	$0
10	Cabling/Misc Equipment	$16,603	10	0	$166,030	$0	$115,640	$0
11	Cabling/Misc Equipment	$10,000	0	12	$0	$120,000	$0	$82,284
12	Cameras	$2,034	470	0	$955,980	$0	$665,840	$0
13	Cameras	$3,000	0	117	$0	$351,000	$0	$240,681
14	Card Access (SIO & SCP)	$1,471	94	0	$138,274	$0	$96,308	$0
15	Lift Charge	$5,017	6	0	$30,102	$0	$20,966	$0
16	Lift Charge	$5,000	0	12	$0	$60,000	$0	$41,142
17	Logistics & Operation Expense	$4,548	6	0	$27,288	$0	$19,006	$0
18	Logistics & Operation Expense	$4,000	0	12	$0	$48,000	$0	$32,914
19	NVR/Monitor	$41,747	11	0	$459,217	$0	$319,845	$0
20	NVR/Monitor	$35,000	0	12	$0	$420,000	$0	$287,994
21	Software, labor, contractor and overhead and other costs				$422,444	$626,400	$294,232	$429,522
22	**Total Electric Allocation**				$2,281,985	$1,625,400	**$1,589,403**	**$1,114,537**

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ARP-Printer Asset Management

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	IM C2500	$5,263	2	5	$10,526	$26,315	$15,789	$10,827
2	IM C300	$1,974	12	9	$23,688	$17,766	$21,714	$14,889
3	IM C3010	$5,743	5	54	$28,715	$310,122	$122,517	$84,010
4	IM C3510	$6,344	8	11	$50,752	$69,784	$57,096	$39,151
5	IM C6010	$7,450	2	12	$14,900	$89,400	$39,733	$27,245
6	IM C8000	$15,744	0	1	$0	$15,744	$5,248	$3,599
7	MP W6700 Plotter	$8,028	0	1	$0	$8,028	$2,676	$1,835
8	MPC W2201	$8,204	2	14	$16,409	$114,862	$49,226	$33,755
9	Ricoh PRO C5300	$34,426	1	0	$34,426	$0	$22,951	$15,737
10	SPC 8200	$6,807	0	1	$0	$6,807	$2,269	$1,556
11	Accessories				$527	$599	$551	$378
12	Software, labor, contractor and overhead and other costs				$2,205	$15,876	$6,762	$4,637
13	**Total Electric Allocation**				$182,148	$675,303	**$346,533**	**$237,618**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
14	IM C2500	$5,235	29	0	$151,825	$0	$105,746	$0
15	IM C2500	$5,263	0	35	$0	$184,205	$0	$126,309
16	IM C300	$1,767	84	0	$148,428	$0	$103,380	$0
17	IM C300	$1,974	0	68	$0	$134,232	$0	$92,043
18	IM C3010	$5,536	12	0	$66,432	$0	$46,270	$0
19	IM C3010	$5,743	0	40	$0	$229,720	$0	$157,519
20	IM C3510	$6,137	60	0	$368,220	$0	$256,465	$0
21	IM C3510	$6,344	0	56	$0	$355,264	$0	$243,605
22	IM C6010	$7,243	21	0	$152,103	$0	$105,939	$0
23	IM C6010	$7,450	0	23	$0	$171,350	$0	$117,495
24	IM C8000	$15,744	0	2	$0	$31,488	$0	$21,591
25	MPC W2201	$8,204	13	0	$106,652	$0	$74,283	$0
26	MPC W2201	$8,204	0	45	$0	$369,180	$0	$253,147
27	Accessories				$0	$2,101	$0	$1,441
28	Software, labor, contractor and overhead and other costs				$87,461	$43,365	$60,917	$29,735
29	**Total Electric Allocation**				$1,081,120	$1,520,905	**$753,000**	**$1,042,885**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Electric and Common Capital Expenditures
For the Projected Year 2025, 2026, and Test Year Ending April 30, 2027
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ARP-Radio

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	800 Mhz mobile radios w/accessories	$2,114	450	450	$951,377	$951,377	$951,377	$492,528
2	Bi-directional Amplifier	$1,411	8	8	$11,287	$11,287	$11,287	$5,843
3	Cellular Modems	$1,920	20	20	$38,400	$38,400	$38,400	$19,880
4	Conventional Repeaters	$9,943	2	0	$19,886	$0	$13,257	$6,863
5	Havis Boxes	$2,256	150	150	$338,456	$338,456	$338,456	$175,218
6	Lighting Alarm Boxes Refresh	$2,500	0	5	$0	$12,500	$4,167	$2,157
7	Software, labor, contractor and overhead and other costs				$635,681	$624,836	$632,066	$327,221
8	**Total Electric Allocation**				$1,995,086	$1,976,855	**$1,989,009**	**$1,029,710**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
9	800 Mhz control stations w/accessories	$2,180	250	0	$544,953	$0	$292,149	$0
10	800 Mhz mobile radios w/accessories	$1,993	100	0	$199,299	$0	$106,844	$0
11	800 Mhz mobile radios w/accessories	$1,806	0	450	$0	$812,570	$0	$420,667
12	800 Mhz portable radios w/accessories	$2,339	5	0	$11,694	$0	$6,269	$0
13	800 MHz Radio Programming Accessories	$296	10	0	$2,961	$0	$1,587	$0
14	Battery conditioners refresh	$2,035	2	0	$4,069	$0	$2,182	$0
15	Bi-directional Amplifier	$31,593	1	0	$31,593	$0	$16,937	$0
16	Bi-directional Amplifier	$2,282	1	0	$2,282	$0	$1,223	$0
17	Bi-directional Amplifier (Commercial)	$726,023	0	1	$0	$726,023	$0	$375,862
18	Bi-directional Amplifier Hardware (cellular)	$15,100	0	10	$0	$151,000	$0	$78,173
19	Bi-directional amplifier w/accessories	$14,352	1	0	$14,352	$0	$7,694	$0
20	Bi-directional amplifier w/accessories	$42,586	1	0	$42,586	$0	$22,830	$0
21	Bi-directional amplifier w/accessories	$18,399	1	0	$18,399	$0	$9,864	$0
22	Bi-directional amplifier w/accessories	$16,314	1	0	$16,314	$0	$8,746	$0
23	Bi-directional amplifier w/accessories	$24,609	1	0	$24,609	$0	$13,193	$0
24	Bi-directional amplifier w/accessories	$12,258	1	0	$12,258	$0	$6,571	$0
25	Cell Scanners	$1,071	4	0	$4,282	$0	$2,296	$0
26	Covert Bi-directional amplifier w/accessories (Office)	$12,888	1	0	$12,888	$0	$6,909	$0
27	Covert Bi-directional amplifier w/accessories (Warehouse)	$1,606	1	0	$1,606	$0	$861	$0
28	Drone Refresh	$6,621	1	0	$6,621	$0	$3,549	$0
29	Havis Boxes	$1,946	17	0	$33,077	$0	$17,732	$0
30	Havis Boxes	$3,419	0	150	$0	$512,850	$0	$265,502
31	Lighting Refresh	$3,210	1	0	$3,210	$0	$1,721	$0
32	Satellite Link Refresh	$5,141	1	0	$5,141	$0	$2,756	$0
33	Satellite Link Refresh	$5,141	1	0	$5,141	$0	$2,756	$0
34	SOM - Activation	$256	0	450	$0	$115,313	$0	$59,697
35	Tool conventional repeater	$3,698	1	0	$3,698	$0	$1,982	$0
36	Watt Meters	$1,376	7	0	$9,635	$0	$5,165	$0
37	Software, labor, contractor and overhead and other costs				$153,953	$622,577	$82,534	$322,308
38	**Total Electric Allocation**				$1,164,617	$2,940,332	**$624,351**	**$1,522,210**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Electric and Common Capital Expenditures
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ARP-Server and Storage

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
1	Nutanix xc640	$137,109	0	8	$0	$1,096,874	$365,625	$250,709
2	Labor, contractor and overhead and other costs				$0	$318,800	$106,267	$72,867
3	**Total Electric Allocation**				$0	$1,415,674	**$471,891**	**$323,576**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
4	Nutanix xc740xd	$32,038	20	0	$640,765	$0	$446,293	$0
5	SFP	$55	40	0	$2,200	$0	$1,532	$0
6	Labor, contractor and overhead and other costs				$57,728	$0	$40,208	$0
7	**Total Electric Allocation**				$700,693	$0	**$488,033**	**$0**

MICHIGAN PUBLIC SERVICE COMMISSION
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ARP-Workstation Asset Mgmt

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2026 Units**	**Total 2027 Units**	**Total 2026 Dollars**	**Total 2027 Dollars**	**Total Test Year Dollars**	**Test Year Electric Allocation Dollars**
	Replacements							
1	16" Lpatop	$3,037	274	191	$832,111	$580,048	$748,090	$512,965
2	Desktops	$1,378	93	480	$128,154	$661,440	$305,916	$209,767
3	HP Desktop Bundled	$3,835	40	73	$153,403	$279,961	$195,589	$134,115
4	Laptop	$1,908	1775	1406	$3,386,700	$2,682,648	$3,152,016	$2,161,337
5	Monitors 24"	$233	0	2159	$0	$503,479	$167,826	$115,078
6	RT Mount Device	$8,692	14	0	$121,688	$0	$81,125	$55,628
7	Tablets	$2,644	0	9	$0	$23,799	$7,933	$5,440
8	Teams Monitors	$323	0	2159	$0	$698,005	$232,668	$159,541
9	Accessories				$231,103	$211,395	$224,533	$153,962
	New Purchases							
10	Workstations, Monitors, and Accessories				$1,000,000	$1,000,000	$1,000,000	$685,700
11	Software, labor, contractor and overhead and other costs				$299,771	$285,781	$295,108	$202,355
12	**Total Electric Allocation**				$6,152,929	$6,926,555	**$6,410,804**	**$4,395,889**

	Units	**Avg. Unit Cost**	**Total 2024 Units**	**Total 2025 Units**	**Total 2024 Dollars**	**Total 2025 Dollars**	**2024 Electric Allocation Dollars**	**2025 Electric Allocation Dollars**
	Replacements							
13	Desktops	$1,540	128	0	$197,098	$0	$137,279	$0
14	Desktops	$1,378	0	141	$0	$194,298	$0	$133,230
15	HP Desktop Bundled	$4,049	0	125	$0	$506,150	$0	$347,067
16	HP Desktops OT	$6,081	65	35	$395,246	$212,825	$275,289	$145,934
17	HP Laptop Bundled	$3,131	512	0	$1,603,308	$0	$1,116,704	$0
18	HP Laptop Bundled	$3,037	0	645	$0	$1,958,801	$0	$1,343,150
19	Laptop	$1,843	912	0	$1,681,236	$0	$1,170,981	$0
20	Laptop	$1,908	0	1841	$0	$3,512,628	$0	$2,408,609
21	Macs	$2,972	0	30	$0	$89,165	$0	$61,141
22	RT Mount Device	$8,480	51	35	$432,480	$296,800	$301,222	$203,516
23	SFF Desktop	$1,562	115	0	$179,592	$0	$125,086	$0
24	Surface Pro Laptops	$3,342	17	0	$56,806	$0	$39,565	$0
25	Tablets	$2,187	39	0	$85,290	$0	$59,405	$0
26	Tablets	$2,151	0	116	$0	$249,480	$0	$171,068
27	Accessories				$148,563	$214,785	$103,474	$147,278
	New Purchases							
28	Desktop (Tower)	$1,540	3	0	$4,619	$0	$3,217	$0
29	HP Desktop	$4,505.00	4	0	$18,020	$0	$12,551	$0
30	HP laptop (16")	$3,131.46	100	0	$313,146	$0	$218,106	$0
31	Laptop (14")	$1,843.46	204	0	$376,066	$0	$261,930	$0
32	SFF Desktop	$1,562	10	0	$15,617	$0	$10,877	$0
33	Surface Pro Tablets	$2,186.93	2	0	$4,374	$0	$3,046	$0
34	Teams Monitors	$323	331	0	$107,012	$0	$74,534	$0
35	Workstations, Monitors, and Accessories				$0	$1,000,000	$0	$685,700
36	Accessories				$115,420	$0	$80,390	$0
37	Software, labor, contractor and overhead and other costs				$259,099	$445,632	$180,462	$305,570
38	**Total Electric Allocation**				$5,992,992	$8,680,563	**$4,174,119**	**$5,952,262**

EXHIBIT A-23 (SHB-8)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis

Information Technology

For Years 2020 Through 2027

($0)

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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)
				Projected Capital								Projected O&M							
	Year	Case No.	Source	2020	2021	2022	2023	2024	2025	2026	2027	2020	2021	2022	2023	2024	2025	2026	2027
1	2020 Total Projected	U-20697	U20697-SA-CE-022 Response	2,082,418								4,417							
2	2021 Total Projected	U-20697	U20697-SA-CE-022 Response		2,742,271								332,943						
3	2022 Total Projected	U-20963	A-108 (JDT-7)			3,897,882								775,423					
4	2023 Total Projected	U-21224	A-171 (JMW-6)				5,877,344								1,663,324				
5	2024 Total Projected	U-21389	A-180 (HNW-6)					6,003,938								1,904,665			
6	2025 Total Projected	U-21585	A-88 (SK-6)						5,648,701								1,946,829		
7	2026 Total Projected	U-21870	A-20 (SHB-5) Confidential							7,868,455								2,512,315	
8	2027 Total Projected	U-21870	A-20 (SHB-5) Confidential								7,133,111								2,465,892
				Actual/Projected Capital								Actual/Projected O&M							
	Project Name	Case No.	Source	2020	2021	2022	2023	2024	2025	2026	2027	2020	2021	2022	2023	2024	2025	2026	2027
9	2020 Total Actuals	U-20963	A-108 (JDT-7)	3,745,910								620,329							
10	2021 Total Actuals	U-21224	A-171 (JMW-6)		5,969,920								2,310,235						
11	2022 Total Actuals	U-21389	A-180 (HNW-6)			10,169,958								3,236,043					
12	2023 Total Actuals	U-21585	A-88 (SK-6)				5,407,278								2,218,122				
13	2024 Total Actuals	U-21870	A-20 (SHB-5) Confidential					4,990,122								2,671,757			
14	2025 Total Projected	U-21870	A-20 (SHB-5) Confidential						13,198,142								3,033,532		
15	Projected to Actual Variance			1,663,492	3,227,649	6,272,076	(470,067)	(1,013,816)	7,549,441			615,912	1,977,292	2,460,620	554,798	767,092	1,086,703		

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis
Information Technology
For Years 2020 Through 2027
($0)

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No.	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Actual/Projected (Capital and O&M)						Projected (Capital and O&M)		
			2020	2021	2022	2023	2024	2025 Projected	2026 Projected	2027 Projected	Test Year
1	Total Electric Projected (Requested) Spend		$ 2,086,835	$ 3,075,214	$ 4,673,305	$ 7,540,669	$ 7,908,603	$ 7,595,530	$ 10,380,770	$ 9,599,002	$ 10,120,181
2	Total Electric Actual/Projected Spend		$ 4,366,238	$ 8,280,154	$ 13,406,001	$ 7,625,400	$ 7,661,879	$ 16,231,674	$ 10,380,770	$ 9,599,002	$ 10,120,181
3	Total Company Incremental Annual Worklist	**	$ 164,509	$ 901,016	$ 2,675,947	$ 4,457,056	$ 16,068,091	$ 7,733,698	$ 1,213,211	$ 2,308,762	$ 1,578,394
4	Total Electric Allocation Incremental Annual Worklist	***	$ 115,683	$ 630,621	$ 1,872,895	$ 3,027,232	$ 11,191,426	$ 5,302,997	$ 831,899	$ 1,583,118	$ 1,082,305
5	Total Electric Annual Demand		$ 4,481,921	$ 8,910,776	$ 15,278,896	$ 10,652,632	$ 11,614,101	$ 12,515,210	$ 11,593,981	$ 11,907,764	$ 11,698,575
6	Total Company Cumulative Worklist		$ 164,509	$ 1,065,526	$ 3,741,473	$ 8,198,529	$ 24,266,620	$ 32,000,318	$ 25,479,831	$ 27,788,593	$ 26,249,418
7	Total Electric Allocation Cumulative Worklist (Demand)	***	$ 115,683	$ 745,762	$ 2,618,657	$ 5,568,441	$ 16,901,701	$ 21,942,618	$ 17,471,520	$ 19,054,638	$ 17,999,226

**2025, 2026, and 2027 projected Total Incremental Annual Worklist based on 3-year average of Total Annual Demand (actual spend plus incremental planned worklist) less projected spend
***Estimated Electric Allocation

Enhancement Worklist Detail
Information Technology
For Years 2016 Through October 21, 2024
($0)

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Open Date	Number	Type	Description	State	Portfolio	Configuration Item	Requestor Department	Total Estimated Hours	Planned Cost
1	1/30/2016	DMND0003200	Enhancement	RM00176542 SAP SD configuration update	Qualified	IT I&AO	SAP CCS BACK OFFICE	Cx&T-IT-TS&M-App Platforms	40	3,177
2	2/1/2016	DMND0003801	Enhancement	Ticket for labor to install a VC system purchased in 2015 for Parnall East	Qualified	Electric & Gas Combined	VIDEO CONFERENCING	Cx&T-IT-IP&S-Digital Ops- IT Constructio	-	9,096
3	2/11/2016	DMND0009972	Enhancement	Install and host the Quality Training Database (QTD) application on CE ser	Screening	Electric	Quality Training Database - QTD	ED GM-System Operations Support	-	-
4	2/15/2016	DMND0010621	Enhancement	RM00095683 Email Notifications for Landlord Portal	Qualified	IT CE&O	LLP	CX&T-Product Experience & Perf	412	32,721
5	3/7/2016	DMND0017568	Enhancement	EDI controls reports are needed	Qualified	Customer	SAP CCS BACK OFFICE	Accounts Payable & Receivable	151	11,992
6	4/4/2016	DMND0025080	Enhancement	OOB Invoices need mailed	Approved	Customer	SAP CCS BACK OFFICE	NON-ENERGY BILLING	94	-
7	6/2/2016	DMND0033513	Enhancement	Feature Add	Qualified	IT I&AO	ServiceNow	CX&T-Security-Network Security	23	1,633
8	6/27/2016	DMND0035603	Enhancement	Correct OOB Invoice Issues	Qualified	Customer	SAP CCS BACK OFFICE	BILLING CNTLS & INTERCOMPANY BILLING	158	12,548
9	7/26/2016	DMND0038277	Enhancement	Delete incorrect/never used mailing addresses in SAP	Qualified	IT CE&O	SAP CCS FRONT OFFICE	Mktg Intel-Mktg Analytics	1,500	119,130
10	10/5/2016	DMND0045344	Enhancement	Allow CRM 7 Alert to Look for Independent Phone Number	Qualified	IT CE&O	CRM7	Rates & Reg-Compliance	183	14,534
11	1/20/2017	DMND0053207	Enhancement	Updates to Non-Compliance area needed	Qualified	IT I&AO	ServiceNow	Cx&T-IT-E&GS-PlanningScheduling&MeterTec	35	2,503
12	5/9/2017	DMND0059073	Enhancement	Automate Test Evidence for SOX compliance in ServiceNow Change Tickets	Screening	IT I&AO	ServiceNow	CX&T-IT-Service Now	-	-
13	6/6/2017	DMND0060183	Enhancement	Block old rates from being used	Qualified	IT CE&O	SAP CCS BACK OFFICE	REVENUE & FUEL ACCOUNTING	104	8,260
14	6/12/2017	DMND0060511	Enhancement	Archive event logs to Event Management archive.	Qualified	IT I&AO	ServiceNow	Cx&T-IT-IP&S-Collaboration & Comms	68	5,401
15	7/26/2017	DMND0062416	Enhancement	Update Closure Rules due to Reschedules	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	64	5,083
16	9/29/2017	DMND0065531	Enhancement	ServiceNow Change: Add Vendor to QA Tester Selection	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	22	1,747
17	10/6/2017	DMND0066076	Enhancement	Add Change Coordinator & Affected CI to Reminder Notification	Qualified	App Platforms & Services	ServiceNow	CX&T-IT-Service Now	22	1,747
18	10/11/2017	DMND0066369	Enhancement	Defects in TMD Creation Tool	Qualified	IT OPS	SAP PM	Lean - Elec Distribution	192	15,249
19	11/9/2017	DMND0067863	Enhancement	Additional Message to protect Inc tied to Chg from being downgraded	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	22	1,548
20	1/12/2018	DMND0070837	Enhancement	Non-Compliance calculations incorrect	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	35	2,780
21	2/6/2018	DMND0072549	Enhancement	Corporate Compliance SharePoint Site	Qualified	Corporate	SharePoint Administration	Ethics and Compliance	-	-
22	5/2/2018	DMND0078158	Enhancement	Create Notification For Code Promotion Task Activities	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	20	1,588
23	5/24/2018	DMND0079420	Enhancement	Revert to OOB for Templates	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	210	16,678
24	7/9/2018	DMND0081337	enhancement	ITAM needs to produce a automated reporting mechanism that tracks SCCM inactive users from the 30 and 60 day SCCM report.	Submitted	Corporate	SCCM Client Center	CX&T-IT-S&G-Asset Management	-	-
25	8/7/2018	DMND0083079	Enhancement	ignore seconds in implementation window failure calculation	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	28	2,224
26	8/17/2018	DMND0083607	Enhancement	Notify Change Coordinator and Technical Manageri Change Tickets	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	22	1,747
27	9/6/2018	DMND0084573	Enhancement	Suppress code promotion/implementation task for non-PROD	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	56	4,448
28	11/14/2018	DMND0088854	Enhancement	Improvements to WeCare Form	Qualified	IT CE&O	Consumers Web Site	CX&T Customer Care	201	15,963
29	12/4/2018	DMND0091325	Enhancement	Internal Correspondence - Deceased; auto fill Interaction Records	Qualified	IT CE&O	SAP CCS FRONT OFFICE	DCO RO-Bankruptcy & Loss	126	10,007
30	1/2/2019	DMND0094966	Enhancement	Tech Val NonCompliance not allowing removal	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	33	2,621
31	1/8/2019	DMND0095213	Enhancement	Don't Require Outage if Parent Change Covers It	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	25	1,775
32	1/11/2019	DMND0095787	enhancement	AccessNOW Request Request	Submitted		AccessNow	Cx&T-IT-S&G-ASDO	-	-
33	1/22/2019	DMND0096689	enhancement	RPA - Automation of Forecasting Template loads to SAP	Submitted		SAP ERP FINANCE	BP&A-DSS Master Data COE	-	-
34	2/5/2019	DMND0098054	Enhancement	Price Automation Tool Enhancement	Qualified	IT CE&O	SAP CCS RATES	Rates & Reg-Rate Administration	171	13,581
35	2/14/2019	DMND0098936	Enhancement	Automation, via an RPA, the steps to get off of BOS	Screening	Customer	SAP CCS FRONT OFFICE	CX&T-IT-Contact Center and Digital Ops	-	-
36	2/21/2019	DMND0099581	Enhancement	Need extended field on an Asset Record called Order Reference Number	Qualified	Governance	ServiceNow	CX&T-IT-IP&S-IT Device Purch & Deploy	52	4,130
37	4/16/2019	DMND0104131	enhancement	Activate Business Process Monitoring KPIs in Solution Manager	Submitted		SAP SolMan - BASIS	Cx&T-IT-S&G-ASDO	-	-
38	4/22/2019	DMND0104479	Enhancement	Remove Technical Validation Complete Button once clicked	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	22	1,747
39	4/22/2019	DMND0104481	enhancement	Export MS Outlook Contacts With an Additional Field (UserId)	Submitted		Outlook	Property Accounting Reporting	-	-
40	5/1/2019	DMND0105248	Enhancement	Create a tool to test the Storm Dashboard that simulates users	Qualified	Electric	Storm Dashboard	Elec GIS LVD Operations	123	9,769
41	5/16/2019	DMND0106408	Enhancement	Add Planned Start/End to CTASK notifications and resend on reschedule	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	25	1,986
42	5/16/2019	DMND0106410	Enhancement	Lock down Contingency Dates field in Change Form	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	14	1,112
43	5/16/2019	DMND0106415	Enhancement	Install Attunity - Replicate on SAP E2S 150	Screening	IT ACDC	SAP ECS	CX&T-IT-Data & Analytics-Platforms	32	2,541
44	6/11/2019	DMND0107862	enhancement	We need to populate the Office field in Asset list from assigned to user.	Submitted		ServiceNow	Cx&T-IT-TS&M-Data Networks Operations	-	-
45	7/9/2019	DMND0109188	Enhancement	Update The GCC Postcard	Qualified	IT TEOS	SAP CCS BACK OFFICE	GE&S/GMS-Gas Cust Choice	108	6,116
46	7/25/2019	DMND0110354	enhancement	Retire Charm old maintenance cycles /phases	Submitted		SAP ECC - BASIS	Cx&T-IT-S&G-ASDO	8	635
47	8/2/2019	DMND0110809	Enhancement	Allow user options of Type and Location for outage notifications	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	97	7,704
48	8/14/2019	DMND0111406	Enhancement	Add Category Item to Service Portal to access Calero VeraSMART	Qualified	Governance	ServiceNow	CX&T-IT-P&G-Vendor & Asset Mgmt	52	7,374
49	8/27/2019	DMND0112063	Enhancement	Need Automation to Track ESB notification failures	Qualified	IT I&AO	ServiceNow	CX&T-IT-Electric Supply & Asset Mgmnt	-	-
50	9/6/2019	DMND0112727	Enhancement	Automate part or all of the Invoice Audit process using a .NET program	Screening	Customer	SAP CCS BACK OFFICE	BILLING CNTLS & INTERCOMPANY BILLING	-	-
51	10/16/2019	DMND0115341	Enhancement	Problem Management Known error state fields.	Qualified	Governance	ServiceNow	Cx&T-IT-Digital Enablement	47	3,733
52	10/28/2019	DMND0115902	Enhancement	ServiceNow Change Form - field default/selection changes	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	66	4,879
53	10/28/2019	DMND0115905	Enhancement	ServiceNow Change: Conflict Checker Automation	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	40	2,976
54	10/30/2019	DMND0116126	Enhancement	Add 'Critical Gas Control Site' checkbox to Locations	Qualified	Governance	ServiceNow	CX&T-IT-Service Now	53	2,922
55	11/8/2019	DMND0116640	Enhancement	Remove PLanned Start End from non-PROD Code promotion tasks	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	13	956
56	11/14/2019	DMND0116902	Enhancement	Allow attachments to the mixed meter investigation orders	Screening	IT CE&O	SAP CCS BACK OFFICE	CX&T-Customer Billing Res	-	-
57	11/26/2019	DMND0117927	Enhancement	Allow Revert to Review in WIP State	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	35	2,503
58	11/26/2019	DMND0117930	Enhancement	Auto-populate & hide category field	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	19	1,331
59	12/6/2019	DMND0118554	Enhancement	PROD Code Promotion Task workflow changes	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	30	2,105
60	12/6/2019	DMND0118555	Enhancement	Change Logic on QA Code Promotion Task	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	24	1,741
61	12/10/2019	DMND0118770	Enhancement	Hide Implementor Field/Prevent Wrong Assignment	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	14	1,023
62	12/11/2019	DMND0118800	Enhancement	Restrict Code Promotion Task Closure	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	30	2,099
63	12/11/2019	DMND0118821	Enhancement	Add "Planned Start Date" of Change Ticket into RM Notifications	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	18	1,296
64	12/11/2019	DMND0118822	enhancement	Disable Messaging in ChaRM	Submitted		SAP SolMan - BASIS	Cx&T-IT-S&G-ASDO	-	-
65	12/20/2019	DMND0119411	Enhancement	Bill Message Update - Previous Amount Due	Qualified	Customer	SAP CCS BACK OFFICE	Rev Ops - Energy Assistance & Payment Pr	31	997
66	2/7/2020	DMND0122639	Enhancement	Tree/Branch/Limb on line add statement if service has been damaged	Qualified	IT CE&O	SAP CCS FRONT OFFICE	CX&T SCC-VCC PMCCS	16	1,188
67	2/14/2020	DMND0123010	Enhancement	CSDD bug found where customers get <21 days due date	Qualified	Customer	SAP CCS BACK OFFICE	Accounts Payable & Receivable	214	15,067
68	2/27/2020	DMND0123665	Enhancement	Digital - Application Programming Interface Fabric	Qualified	App Platforms & Services	MemSQL Database	Cx&T-IT-Strategy & Governance	520	33,920
69	2/27/2020	DMND0123697	Enhancement	UIPath to Replace BluePrism for Unattended	Qualified	IT ACDC	UiPath	CX&T-IT-Development Foundation	270	22,584
70	3/4/2020	DMND0123989	Enhancement	How do we ensure the SHP Printers	Screening	Gas	EcoPrint-ADR-Printer PS	Operations Software & Technology	-	-
71	3/20/2020	DMND0125045	Enhancement	Provide a Quick Link to Bill Impact Tool for all Contact Center Staff Memb	Screening	IT CE&O	Customer Portal Admin	CX&T-Quality & Data Systems	-	-
72	4/30/2020	DMND0126971	Enhancement	Upgrade Quest Password Manager to latest version	Screening	IT I&AO	Password Manager	CX&T-IT-IP&S-Automation & Virtual Sprt	1	79
73	5/21/2020	DMND0128366	enhancement	Allow Copying of Standard Change Templates between Teams	Submitted		ServiceNow	CX&T-Security-Security Infra & Delivery	-	-
74	6/8/2020	DMND0129099	Enhancement	SAP Exception - Host Inquiry Work Order Creation Failed. Functional Locati	Qualified	Electric & Gas Combined	SAP WORK ORDERS	Operations Software & Technology	360	25,948
75	6/10/2020	DMND0129408	enhancement	Service Suite Mobile app - priority customer and highlight key work orders	Submitted		Service Suite	Cx&T-IT-Work and Asset Management	-	-
76	6/23/2020	DMND0130727	Enhancement	Reconfigure Timing and Frequency of Emergency Change Closure Notifications	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	17	1,284
77	7/9/2020	DMND0132134	Enhancement	Auto assign tickets Remote Desktop team based on availabity and capacity	Qualified	Infra Platforms & Services	ServiceNow	Deskside Support Jackson	80	5,942
78	8/4/2020	DMND0133953	Enhancement	VR - Class Grouping & Assignment Rules Enhacement - Elevated access	Qualified	Infrastructure Platforms & Services	ServiceNow	Cx&T-IT-IP&S-Monitoring	52	3,851
79	8/7/2020	DMND0134229	Enhancement	Set up Azure Cloud Discovery in our Service Now tenants	Qualified	Strategy	Service Catalog	CX&T-IT-Development Foundation	40	2,630
80	10/26/2020	DMND0141119	Enhancement	Timesheet Approval and Validation	Screening	IT CE&O	UiPath	CX&T-Quality & Data Systems	-	-
81	10/26/2020	DMND0141123	Enhancement	Third Pary Notification	Screening	IT CE&O	UiPath	CX&T-Quality & Data Systems	-	-
82	10/26/2020	DMND0141218	Enhancement	Allow Non Energy Account Over Payment	Screening	IT CE&O	SAP CCS FRONT OFFICE	CX&T-Digital Operations	-	-
83	10/27/2020	DMND0141417	Enhancement	Closure Failure Calculation Causing False Non-Compliances in ServiceNow CR	Qualified	Governance	ServiceNow	Cx&T-IT-S&G-ASDO	29	1,920
84	11/13/2020	DMND0143177	Enhancement	Infoblox in Azure	Screening	Infra Platforms & Services	Infoblox	CX&T-IT-Development Foundation	212	16,837
85	12/4/2020	DMND0144441	Enhancement	CatCrew Enhancements: Dispatch Whiteboard & CE Resource Availability form	Qualified	Strat & Govern	Catastrophic Crewing - CatCrew	ED GM-LVD Dispatch	177	11,941
86	12/4/2020	DMND0144489	Enhancement	SAP CM40 automation enhancement	Qualified	Electric	SAP WORK ORDERS	Cx&T-IT-Work and Asset Management	303	21,318
87	1/4/2021	DMND0145977	Enhancement	Access to work order creation for CSRs OPT/OUT/GAS/GCM/SMART/METER	Qualified	Customer	SAP CCS FRONT OFFICE	CX&T SCC-CCC Policy & Procedures	6,876	869
88	1/4/2021	DMND0146047	Enhancement	Integration of request and incident ticket workflows with Pitney Bower	Qualified	Infrastructure Platforms & Services	ServiceNow	Deskside Support Jackson	68	18,005
89	1/8/2021	DMND0146402	Enhancement	work order creation - hard stop for select orders	Qualified	IT CE&O	CRM7	CX&T SCC-CCC Policy & Procedures	1,500	10,921
90	1/14/2021	DMND0146665	enhancement	Upgrade the Dialog Direct Call Center Infrastructure/Platform	Submitted		SAP CCS BACK OFFICE	Cx&T-IT-Cust-Rates Rev Gen & Collect	-	-
91	1/22/2021	DMND0147200	enhancement	CRM work order processing - change to 911 Call Summary	Submitted		SAP CCS FRONT OFFICE	CX&T SCC-CCC Policy & Procedures	-	-
92	1/22/2021	DMND0147203	Enhancement	ServiceNow Vulnerability Response - Integration Run Monitoring and Notific	Qualified	Infrastructure Platforms & Services	ServiceNow	Cx&T-IT-IP&S-Monitoring	81	6,026
93	1/27/2021	DMND0147471	enhancement	Mass Ping Tool v2	Submitted		OMS Bulletin Board	ED GM-LVD Dispatch	-	-
94	1/27/2021	DMND0147522	enhancement	SAP Post Data Refresh - CRB Contract Accounts	Submitted		SAP CCS BACK OFFICE	Cx&T-IT-S&G-ASDO	-	-
95	1/31/2021	DMND0147677	Enhancement	SAP Post Data Refresh - Missing business roles in CRM	Screening	Governance	SAP CCS BACK OFFICE	Cx&T-IT-S&G-ASDO	-	-
96	2/12/2021	DMND0148711	enhancement	Adding Orig_Read field to Meter Reader Error Report	Submitted		SAP CCS BACK OFFICE	GE&S/GAM/SI-TIMP	-	-
97	3/10/2021	DMND0150357	enhancement	Damage Assessment Mobile App - New Functionality	Submitted		Outage Management System - ON	Lean - Elec Distribution	-	-
98	3/16/2021	DMND0150717	Enhancement	A standardized way to get the SSO integration process started with new pro	Qualified	App Platforms & Services	ServiceNow	CX&T-Security-Identity Platforms	136	8,751
99	4/7/2021	DMND0151823	enhancement	Automatic Outage Notifications	Submitted		Storm Dashboard	Lean - Elec Distribution	-	-
100	4/20/2021	DMND0152479	Enhancement	SAP to IEE Sync Send Only Current Time Slice	Qualified	IT CE&O	IEE	EO-Smart Energy Operations A	-	26,106
101	4/21/2021	DMND0152549	Enhancement	Develop new Bill Consolidator Code in SAP	Screening	IT TEOS	SAP CCS BACK OFFICE	GE&S/GMS-Gas Transport & Cust Choice	-	-
102	4/26/2021	DMND0152732	Enhancement	Create a new catalog item	Qualified	Infrastructure Platforms & Services	ServiceNow	CX&T-IT-IP&S-Automation & Virtual Sprt	41	2,605
103	4/29/2021	DMND0152957	enhancement	Rel Mgmt - Reduce SAP manual transport code inspection	Submitted		SAP Quality Management	Cx&T-IT-S&G-ASDO	-	-
104	5/10/2021	DMND0153609	Enhancement	Electric Inspections Application Enhancements	Screening	Electric	Electrical Inspection Web	Cx&T-IT-Work and Asset Management	-	144,552

Enhancement Worklist Detail
Information Technology
For Years 2016 Through October 21, 2024
($0)

Line No.	(a) Open Date	(b) Number	(c) Type	(d) Description	(e) State	(f) Portfolio	(g) Configuration Item	(h) Requestor Department	(i) Total Estimated Hours	(j) Planned Cost
105	5/13/2021	DMND0153878	Enhancement	Orders which are modified in the undated folder in service suite to not dr	Qualified	Electric & Gas Combined	SAP EAM Interface	GO-Gas Scheduling SE	745	53,739
106	5/20/2021	DMND0154463	Enhancement	Implement a Master Data intake work flow with approvals and communications	Qualified	Corporate	SAP ERP FINANCE	BP&A-DSS Master Data COE	2,079	150,170
107	6/21/2021	DMND0156801	enhancement	Implement SSO and MFT for Arcos mobile app at CE	Submitted		ARCOS	CX&T-IT-S&G-Strategy E&A	-	-
108	6/28/2021	DMND0157183	Enhancement	Improve the EMMA case routing protocol	Qualified	IT CE&O	SAP CCS BACK OFFICE	CX&T-Cust Ops Projects & Support	440	30,468
109	6/29/2021	DMND0157270	Enhancement	non-emergency changes required for order summaries in CRM	Qualified	IT CE&O	SAP CCS FRONT OFFICE	CX&T SCC-CCC Policy & Procedures	16	1,324
110	7/7/2021	DMND0157740	Enhancement	EDI invoice testing/setup for Radius Point trading partner	Screening	Customer	SAP CCS BACK OFFICE	BILLING CNTLS & INTERCOMPANY BILLING	-	-
111	7/8/2021	DMND0157907	Enhancement	Production Pipeline Job Failure Notifications	Screening	IT CE&O	SAP CCS FRONT OFFICE	CX&T-IT-CEO-Proj Mgmt	-	-
112	7/29/2021	DMND0159320	enhancement	Need Access for GIS ARCMAP for Staking Contractors at minimal a VIEW ONLY Access	Submitted		GIS	GE&S-Damage Prev East	-	-
113	8/4/2021	DMND0159709	Enhancement	Rate Optimization Phase 2	Approved	Customer	SAP CCS BACK OFFICE	Rates & Reg-Rate Administration	2,394	199,551
114	8/4/2021	DMND0159710	enhancement	Cannot directly open ChaRM unless logged into SolMan	Submitted		ServiceNow	Cx&T-IT-S&G-ASDO	-	-
115	8/9/2021	DMND0160130	Enhancement	Send additional Current Occupant turn off letter every 120 days	Qualified	IT CE&O	SAP CCS FRONT OFFICE	DCO-Rev Ops-Credit Operations	136	9,464
116	8/17/2021	DMND0160575	Enhancement	VR - Build Backfill Job to correct Missing VIT Data	Qualified	Infrastructure Platforms & Services	ServiceNow	Cx&T-IT-IP&S-Monitoring	46	2,936
117	8/26/2021	DMND0161178	Enhancement	In ServiceNow Change Form, Hide Change Manager Exception from ITIL Users	Approved	Governance	ServiceNow	CX&T-IT-S&G-ASDO	38	2,464
118	9/13/2021	DMND0162757	Enhancement	Automated Developer Environments	Approved	App Platforms & Services	Azure DevTest Labs	CX&T-IT-S&G-Strategy E&A	1,277	101,419
119	10/1/2021	DMND0164324	enhancement	Load COMET Data to Dataverse	Submitted		Microsoft Dynamics 365 COMET	CX&T-IT-Contact Center and Digital Ops	-	-
120	10/1/2021	DMND0164333	enhancement	dataverse request	Submitted		SAP	Supply Chain Systems	-	-
121	10/7/2021	DMND0164923	enhancement	Enhancement to az_restoration_predictions	Submitted		SAP BI	CXCO Customer Data Analytics	-	-
122	10/8/2021	DMND0164942	Enhancement	INC0738630 - Not displaying all the Device Location remark - DMND0143012 -	Qualified	Gas	SAP WORK ORDERS	Operations Software & Technology	-	24,000
123	10/8/2021	DMND0165038	Enhancement	Service Catalog > Hardware, Work Order field validation	Qualified	Governance	ServiceNow	CX&T-IT-S&G-Asset Management	96	6,180
124	10/13/2021	DMND0165335	enhancement	RPA: SAP cust acct note on gas incidents to track restoration start to fi	Screening		SAP WORK ORDERS	Cx&T-IT-Gas Supply & Asset Mgmnt	-	-
125	10/18/2021	DMND0165596	enhancement	Configure Okta for use with Adobe SSO	Submitted		Adobe Acrobat	CX&T-Security-Identity Orchestration	-	-
126	10/27/2021	DMND0166120	Enhancement	APIM - API Catalog Portal	Approved	App Platforms & Services	Azure APIM Development	CX&T-IT-Apps, Platforms & Services	690	52,709
127	10/28/2021	DMND0166203	Enhancement	allow field to correct the stand type left on meter orders	Qualified	Gas	Service Suite	GO-Gas Dispatch & Scheduling Support	403	24,757
128	11/8/2021	DMND0166799	enhancement	PowerApps team to build a new maturity scale & dashboard	Submitted		N/A	Ethics and Compliance Oversight	-	-
129	12/3/2021	DMND0168261	Enhancement	Loading Meter Read Test Data on External Test Environments	Screening	IT CE&O	SAP CCS BACK OFFICE	Cx&T-IT-Cust-Rates Rev Gen & Collect	-	-
130	12/8/2021	DMND0168553	Enhancement	Add two new SAP Task List & Operation transactions IA38 & IA39	Qualified	Gas	SAP WORK ORDERS	Operations Software & Technology	-	24,000
131	1/5/2022	DMND0169644	Enhancement	New hardware storage for video communications team	Qualified	IT I&AO	Juniper Network Connect Client &	CX&T-IT-CPF-P&C	-	297,715
132	1/10/2022	DMND0169926	Enhancement	FIN / FOS team would like to automate time premiums for 16 hour shift wast	Qualified	Gas	SAP EAM Interface	Operations Software & Technology	308	17,599
133	1/12/2022	DMND0170179	Enhancement	Improvements to Personas	Qualified	Gas	SAP PERSONAS GEN & RENEWABL	LUDINGTON PUMP STORAGE MAINTENANCE	84	19,000
134	1/18/2022	DMND0170456	Enhancement	Gas Bypass Phase 4	Screening	Gas	SAP WORK ORDERS	Cx&T-IT-DCO-Work Mgmt	-	-
135	1/23/2022	DMND0170762	enhancement	Add Maintenance WK Center Identifier to GIS database	Submitted		GIS	GE&S/Gas Asset Info/Gas Distribution	-	-
136	1/27/2022	DMND0171205	Enhancement	Cell Phone notification if near a TOV	Submitted		Threats Of Violence Map Layer	Electric Operations Safety	-	-
137	2/2/2022	DMND0171628	enhancement	AutoETR A/B Testing	Submitted		oms	CXCO Customer Data Analytics	-	-
138	2/22/2022	DMND0173316	enhancement	Outage cause logic and automation of cause when Hazard is associated with outage	Submitted		Outage Management System - ON	GM-Products & Reporting	-	-
139	2/22/2022	DMND0173320	enhancement	Need software to automate and track MPSC compliance requirements and rules	Submitted		SAP	Rates & Reg-Compliance	-	-
140	3/1/2022	DMND0173772	Enhancement	Streetlight Mapping Update for non-CE Lighting	Submitted		Service Suite	Electric Distribution Strategy	-	-
141	3/8/2022	DMND0174317	Enhancement	Damage Assessment App for ArcGIS Enterprise	Submitted		ArcGIS	Electric GIS	-	-
142	3/8/2022	DMND0174353	Enhancement	ConsumersEnergy.com 'Brute Force' Vulnerability	Approved	Customer	SAP CCS FRONT OFFICE	CX&T-Digital Operations	1,428	200,000
143	3/11/2022	DMND0174752	Enhancement	SAP TMD Tool Update - Will Run out of 250RM Meters by October - Required C	Screening	Gas	SAP DESIGN DOCUMENTS	WM&CD Process Perf & Tech	-	-
144	3/14/2022	DMND0174883	enhancement	Implement Net Metering Calc in SAP for C&I accounts	Submitted		SAP CCS BACK OFFICE	CX&T-Customer Billing B	-	-
145	3/14/2022	DMND0174898	enhancement	Guest Pay ACH	Submitted		SAP CCS FRONT OFFICE	CX&T-Digital Operations	-	-
146	3/16/2022	DMND0175111	Enhancement	AppCurr-Gas - SIMSWeb 2023	Approved	Gas	SIMSWeb	Technology Portfolio Management	530	26,890
147	3/17/2022	DMND0175262	enhancement	Asset Audit/Invenotry - Mobile Functionality	Submitted		ServiceNow	CX&T-IT-S&G-Asset Management	-	-
148	3/23/2022	DMND0175569	Enhancement	Removal of Green Tag Device location when Notification is Complete	Qualified	Electric	SAP NOTIFICATIONS	GO-Gas Dispatch	305	21,360
149	3/23/2022	DMND0175653	Enhancement	Automation of Change and Release Process between ServiceNow and Azure DevO	Approved	App Platforms & Services	ServiceNow - PROD	CX&T-IT-S&G-Strategy E&A	524	40,803
150	4/1/2022	DMND0176410	enhancement	Enable ChaRM Creation While Change Request is in WIP	Submitted		ServiceNow	Cx&T-IT-S&G-ASDO	-	-
151	4/4/2022	DMND0176529	enhancement	e-Bills - would like to add e-Bill personalization to SMB customers	Submitted		SAP CCS FRONT OFFICE	CX&T-Residential ET	-	-
152	4/4/2022	DMND0176532	enhancement	On-Call Schedule Process - Agent Swaps	Submitted		SAP CCS FRONT OFFICE	CX&T RP TECH	-	-
153	4/12/2022	DMND0177112	enhancement	MAOP - Remove bad system values from publication	Submitted			Technology Portfolio Management	-	-
154	4/13/2022	DMND0177253	Enhancement	GAS BYPASS UPGRADES 175/250 CHANGES	Screening	Gas	SAP WORK ORDERS	Cx&T-IT-DCO-Work Mgmt	437	28,162
155	4/14/2022	DMND0177405	enhancement	Guest Pay ACH to Use Existing Payment Source	Submitted		ESB	CX&T-Digital Operations	-	-
156	4/20/2022	DMND0177795	enhancement	MV90 Evaluation for Company IT Standards	Submitted		MV90 - Distributed	EO-Smart Energy Operations A	-	-
157	4/25/2022	DMND0178109	enhancement	Updating and long term storage of Sitecore data tables created from ASP.co	Submitted		SAP CCS FRONT OFFICE	CX&T-IT-Contact Center and Digital Ops	-	-
158	4/28/2022	DMND0178405	enhancement	Update calculations on a Sharepoint Online Site	Submitted		SharePoint	GE&S/GAM/Measurement Reliability & Engin	-	-
159	5/2/2022	DMND0178625	Enhancement	New Alert needed for new field process when an action is needed for a prem	Qualified	IT CE&O	SAP CCS FRONT OFFICE	CX&T SCC-CCC Policy & Procedures	12	845
160	5/3/2022	DMND0178662	Enhancement	For RegCfg error msgs for MR doc, implement functionality to reverse MR do	Qualified	Customer	SAP CCS BACK OFFICE	CX&T-Cust Ops Projects & Support	300	16,664
161	5/11/2022	DMND0179299	Enhancement	Changes to Electric GIS Web Viewer	Qualified	Electric	Electric GIS	Electric GIS	81	6,024
162	5/20/2022	DMND0179928	Enhancement	Data Lake for SAP/OpenText Vendor Invoice management	Approved	Corporate	SAP ERP ACCOUNTS PAYABLE	Cx&T-IT-CPF-Corporate Shared Products	420	29,982
163	5/24/2022	DMND0180044	Enhancement	Performance Manager	Approved	IT TEOS	Itron Performance Manager (IPM)	Technology Portfolio Management	170	12,080
164	5/24/2022	DMND0180046	Enhancement	FDM	Approved	App Platforms & Services	FDM CMS	Technology Portfolio Management	170	12,080
165	5/24/2022	DMND0180079	enhancement	To give non-energy customers the choice to set up their invoice electronically	Submitted		Customer facing websites	Real Estate-Proj Controls	-	-
166	5/24/2022	DMND0180102	enhancement	Business Case Development - ITVAM Tool Enhancement for IT Services Suppli	Submitted		Enlighta Govern	Cx&T-IT&S-Technology Portfolio Office	-	-
167	5/26/2022	DMND0180210	Enhancement	ArcFM Web for Electric GIS Web tracing	Qualified	Electric	Electric GIS	Electric GIS	100	9,657
168	5/27/2022	DMND0180347	enhancement	Business Case Development - IT VM Tool Enhancement for IT Hardware Suppliers	Submitted		Enlighta Govern	Cx&T-IT&S-Technology Portfolio Office	-	-
169	5/27/2022	DMND0180349	enhancement	Business Case Development - IT VM Tool Enhancement for IT Software Suppliers	Submitted		Enlighta Govern	Cx&T-IT&S-Technology Portfolio Office	-	-
170	6/2/2022	DMND0180637	Enhancement	Implement Phase 2 - SW Uninstall Process Automation	Approved	App Platforms & Services	ServiceNow	CX&T-IT-P&G-Vendor & Asset Mgmt	240	11,671
171	6/6/2022	DMND0180751	Enhancement	Power BI add-in for PowerPoint	Screening	IT CE&O	Microsoft 365 - Exchange	CXCO Customer Data Analytics	2	159
172	6/8/2022	DMND0180878	Enhancement	Expand ConsumersEnergy.com Sitecore Front-End Servers from 4 to 6	Approved	Customer	Sitecore	CX&T-Digital Operations	2,262	166,265
173	6/13/2022	DMND0181141	Enhancement	SN - Modify and Add fields to Purchase Requests	Qualified	Application Platforms & Services	ServiceNow	Supply Chain Systems	80	3,886
174	6/28/2022	DMND0181878	enhancement	Append INC# to ADO Card Title for OT	Submitted		ServiceNow	CX&T-IT-Service Now	-	-
175	7/1/2022	DMND0182147	Enhancement	ARCOS to SAP Integration For Work Schedules	Approved	Corporate	ARCOS	P&C-Employee Services	578	50,216
176	7/15/2022	DMND0182656	Enhancement	Send ALL related MissDig Ticket Information to Service Suite	Qualified	Gas	SAP WORK ORDERS	Cx&T-IT-Work and Asset Management	2,679	202,593
177	7/18/2022	DMND0182699	enhancement	Add High Bill Alert Enrollment for Gas AMI Customers	Submitted		Energy Usage Dashboard	Exp Design Utility Services	-	-
178	8/3/2022	DMND0183703	Enhancement	Add CT Ratio verification to EMITS work orders	Qualified	Gas	Service Suite	EO-Elec Meter Ops	930	56,001
179	8/8/2022	DMND0183884	Enhancement	Provide rotation indicator field on metering polyphase self-contained work	Qualified	Electric	SAP WORK ORDERS	EO-Elec Meter Ops	1,173	74,542
180	8/10/2022	DMND0183990	Enhancement	Hard Stop for premises the require an inspection	Screening	Customer	CRM7	CX&T-Customer Billing Res	-	-
181	8/11/2022	DMND0184042	Enhancement	2023: Change Sync of Ownership Attributes - Owned by and Managed by for As	Approved	App Platforms & Services	ServiceNow	Cx&T-IT-Digital Enablement	55	2,973
182	8/16/2022	DMND0184229	enhancement	add a space on the storm dashboard of accumulative outages for that day	Submitted		SAP CCS FRONT OFFICE	CX&T RP TECH	-	-
183	8/24/2022	DMND0184689	Enhancement	Change MDUS delay	Screening	Customer	SAP CCS BACK OFFICE	CX&T-Customer Billing Res	-	-
184	8/24/2022	DMND0184751	Enhancement	VR Training - Pigging and other modules	Approved	Gas	OQ Plus	CX&T-IT-Gas	324	485,075
185	8/29/2022	DMND0184943	enhancement	Service Suite missing field for CT Ratio from MITS and ITR Orders	Submitted		SAP WORK MANAGEMENT	EO-Elec Mtr Ops-Zone 7	-	-
186	8/30/2022	DMND0185080	Enhancement	2023: Implement Standard Change Catalog in ServiceNow	Qualified	App Platforms & Services	ServiceNow	Cx&T-IT-S&G-ASDO	143	6,985
187	8/31/2022	DMND0185188	Enhancement	2023: Add 3 new fields to the Asset form	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	176	9,387
188	9/6/2022	DMND0185333	enhancement	PowerAutomate/PowerApps connector to datalake Lab	Submitted		cms data lake.ce.corp.com	Supply Chain Systems	-	-
189	9/6/2022	DMND0185350	enhancement	2023: Build out Phase III of IT Vendor Management in ServiceNow	Submitted		ServiceNow	Cx&T-IT&S-Technology Portfolio Office	-	-
190	9/6/2022	DMND0185351	enhancement	2023: Build out of ServiceNow for IT Vendor Management - Phase II	Submitted		ServiceNow	Cx&T-IT&S-Technology Portfolio Office	-	-
191	9/9/2022	DMND0185584	Enhancement	2023: Update Text on Software Catalog Items that are not free	Approved	App Platforms & Services	ServiceNow	Cx&T-IT-Digital Enablement	31	1,533
192	9/15/2022	DMND0185758	Enhancement	SAP table to store indirect sharing of ToV data between SAP and Endeavor	Approved	Infra Platforms & Services	SAP CCS BACK OFFICE	CX&T-IT-Contact Center and Digital Ops	146	8,129
193	9/15/2022	DMND0185773	Enhancement	Unifier to Primavera P6 Integration	Qualified	Energy Combined	Unifier	Enterprise Project Management Office	532	44,915

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Line No.	(a) Open Date	(b) Number	(c) Type	(d) Description	(e) State	(f) Portfolio	(g) Configuration Item	(h) Requestor Department	(i) Total Estimated Hours	(j) Planned Cost
194	9/16/2022	DMND0185822	enhancement	Create or repurpose an unused EMO work order mat type for commissioning tests	Submitted		SAP WORK ORDERS	EO-Elec Meter Ops	-	-
195	9/19/2022	DMND0185867	Enhancement	GCCP SIMS Data Conversion	Qualified	Gas	SIMS Integration	Technology Portfolio Management	1,891	145,573
196	9/20/2022	DMND0185951	Enhancement	EFLC Automation RPA WE#15025	Approved	Electric	Blue Prism RPA	CX&T-IT-S&G-Strategy E&A	755	51,431
197	9/26/2022	DMND0186329	Enhancement	Supplemental eBill at Move Out	Qualified	Customer	SAP CCS FRONT OFFICE	CX&T-Digital Operations	171	9,573
198	9/28/2022	DMND0186510	Enhancement	PQView 4 - Version upgrade	Qualified	Energy Combined	PQView	Technology Portfolio Management	-	8,552
199	9/29/2022	DMND0186597	Enhancement	Wireless Device Batch File Transfer from VeraSmart to ServiceNow	Qualified	Corporate	ServiceNow	Cx&T-IT-IP&S-Smart Ops & Analytics	246	12,046
200	10/3/2022	DMND0186784	enhancement	Bill enhancement - credit do not pay	Submitted		SAP CCS BACK OFFICE	Rev Ops - Energy Assistance & Payment Pr	-	-
201	10/3/2022	DMND0186788	enhancement	Add New "Switched to Normal Change Process" Option in Std Change templates	Submitted		ServiceNow	Cx&T-IT-S&G-ASDO	-	-
202	10/3/2022	DMND0186796	enhancement	AUTOMATE C1 NOTIFICATION TASK ASSIGNMENT BASED OFF FUNCTIONAL LOCATION	Submitted		SAP NOTIFICATIONS	Street Lighting	-	-
203	10/11/2022	DMND0187345	enhancement	AutoETR Enhancements and A/B Testing	Submitted		Outage Management System - ON	CXCO Customer Data Analytics	-	-
204	10/17/2022	DMND0187645	Enhancement	P6 Integration using the Impress Tool	Qualified	Energy Combined	Primavera P6	Enterprise Project Management Office	577	48,356
205	10/18/2022	DMND0187754	Enhancement	2023: Asset form updates to the "Hard drive wiped status" dropdown menu	Approved	Strat & Govern	ServiceNow	CX&T-IT-S&G-Asset Management	78	3,817
206	10/19/2022	DMND0187822	enhancement	Request access to Dataverse	Submitted		Power BI	IT-D&A Services-Data Architects	-	-
207	10/19/2022	DMND0187832	enhancement	U21224 Price Updates and Line Loss Factor Updates	Submitted		SAP CCS BACK OFFICE	Rates & Reg-Rate Administration	-	-
208	10/19/2022	DMND0187851	Enhancement	2023: IT VDI Request workflow to remove the Supply Chain T&C Review step	Approved	App Platforms & Services	ServiceNow	Cx&T-IT-S&G-ASDO	63	3,066
209	10/20/2022	DMND0187897	Enhancement	SOAR Instructional Pop Up to appear daily	Qualified	Customer	Azure AD Authentication Connecti	Exp Design Utility Services	90	4,810
210	10/21/2022	DMND0187973	Enhancement	Banner on SOAR during Storms	Qualified	Customer	Azure AD Authentication Connecti	Exp Design Utility Services	190	10,143
211	10/26/2022	DMND0188322	Enhancement	Account Lookup Error Table	Qualified	Customer	SAP CCS FRONT OFFICE	CX&T-Digital Operations	312	17,348
212	10/26/2022	DMND0188329	enhancement	GIS / SAP Functional loc / TRS comp for HDQ assign & trans	Submitted		GISElectric	Operations Software & Technology	-	-
213	10/26/2022	DMND0188366	enhancement	Complete the build of the ADMS integrated training environment	Submitted		Outage Management System - ON	Cx&T-IT-Grid Management	-	-
214	10/27/2022	DMND0188394	enhancement	On-premise Data gateway on our Server cvmwnt2934	Submitted		SAP BI	OP-Digital Products-II	-	-
215	10/31/2022	DMND0188533	Enhancement	Contaminated/Enviro. Safety message	Qualified	Gas	SAP WORK ORDERS	GO-Gas Distribution-East-Zone-2D	796	54,133
216	11/9/2022	DMND0189160	Enhancement	Change SAP WO Business Process to allow CRTD WOs with FCMP status to be re	Qualified	Energy Combined	SAP WORK ORDERS	Operations Software & Technology	558	40,431
217	11/15/2022	DMND0189382	Enhancement	Need for real-time data to support our Storm Restoration Wait-Time Tracker (real	Qualified	Energy Combined	Power BI	OP-Product Implementation-I	-	236,882
218	11/21/2022	DMND0189719	enhancement	Creation of an Intelligent Process Agent to classify records	Submitted		Total Information Management (E	Cx&T-IT-CPF-Corporate Shared Products	-	-
219	11/21/2022	DMND0189727	enhancement	Enhance Storm Dashboard to include additional Restoration key metrics	Submitted		Storm Dashboard	Cx&T-IT-Work and Asset Management	-	-
220	11/29/2022	DMND0189941	Enhancement	Customer Photos available in SOAR Admin Panel	Qualified	Customer	Azure AD Authentication Connecti	Exp Design Utility Services	59	3,159
221	12/5/2022	DMND0190151	Enhancement	Gas Site Conditions Customer Contact Management and Automation	Screening	Electric	SAP NOTIFICATIONS	Cx&T-IT-Work and Asset Management	-	-
222	12/5/2022	DMND0190166	enhancement	Enhancement to our Report 20, PowerBi Reporting	Submitted		Power BI	WM&CD Process Perf & Tech	-	-
223	12/6/2022	DMND0190287	enhancement	Voluntary Green Pricing Programs Billing Automation - LCREP Automation	Screening		SAP CCS RATES	CX&T-Cust Regulatory & Compliance	2,000	158,840
224	12/7/2022	DMND0190324	enhancement	Encrypt printer data over the network	Submitted		Pitney Bowes DocuMatch? Job De	Deskside Support Jackson	-	-
225	12/9/2022	DMND0190430	Enhancement	Decommissioning Workflow Requirements	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	94	4,596
226	12/13/2022	DMND0190554	enhancement	Eliminate paperwork(3032) for letters and postcards under 500 pieces.	Submitted		SAP CCS BACK OFFICE	Output & Mail Processing	-	-
227	12/14/2022	DMND0190693	enhancement	Need a new Critical/Priority code added to SAP	Submitted		Business Partner Services	GM-Products & Reporting	-	-
228	1/6/2023	DMND0191301	Enhancement	Stand up ADMS Integrated Training Environment	Approved	Electric	ADMS OMS	L&D Generation & Ops Support	504	32,376
229	1/11/2023	DMND0191510	Enhancement	TIM Upgrade	Approved	Corporate	Total Information Management (E	CX&T-IT-Corporate Product Family	698	50,032
230	1/11/2023	DMND0191517	Enhancement	EICP (move data-) and decommission hardware	Approved	Corporate	EICP	CX&T-IT-Corporate Product Family	283	20,240
231	1/11/2023	DMND0191525	Enhancement	UI Planner - server and database upgrade	Qualified	Corporate	UIPlanner	CX&T-IT-Corporate Product Family	-	25,745
232	1/17/2023	DMND0191755	Enhancement	VR- Bifurcate OS and Non OS vulnerbilities at Third Party Library	Approved	Corporate	ServiceNow	Cx&T-IT-IP&S-Monitoring	63	3,098
233	1/17/2023	DMND0191851	Enhancement	Electric Contractor Scheduling Personas Screen	Qualified	Energy Combined	SAP PERSONAS DISTR SCHEDULIN	WM&CD Gas Planning & Resource Mgmt-CTR	281	16,126
234	1/18/2023	DMND0191905	enhancement	Need data on customer account balance	Submitted		SAP CCS BACK OFFICE	GE&S/GMS-Gas Cust Choice	-	-
235	1/23/2023	DMND0192099	Enhancement	Need Enhancements to Custom Transaction ZSCE420_PROCESS_ERR2 - Sort Error	Qualified	Energy Combined	SAP WORK MANAGEMENT	EO-Smart Energy Operations A	443	25,728
236	1/27/2023	DMND0192348	Enhancement	Share GIS Information with External Stakeholders	Approved	Electric	ArcGIS	Technology Portfolio Management	844	187,800
237	1/30/2023	DMND0192467	enhancement	Automate Monthly MIC-6 Reporting	Submitted		ServiceNow	Cx&T-IT-S&G-ASDO	-	-
238	1/30/2023	DMND0192471	enhancement	Automate/Simplify Annual Standard Change Template Recertification	Submitted		ServiceNow	Cx&T-IT-S&G-ASDO	-	-
239	2/10/2023	DMND0193379	Enhancement	Calendar that will integrate multiple different planning calendars into 1 place	Qualified	Corporate	Power BI	CX&T - Channels	-	10,594
240	2/22/2023	DMND0194019	Enhancement	Website SMB STP Enrollment	Qualified	Customer	Consumers Web Site	CX&T-Digital Operations	110	5,855
241	2/23/2023	DMND0194195	Enhancement	Would like to have Romet test files uploaded to SAP from excel or like fil	Qualified	Electric	SAP QM	EO - MTC Production and Logistics.	281	15,612
242	2/24/2023	DMND0194257	Enhancement	Upgrade EMMAX to Release 5 with Support Package 4 and configure PAM enhanc	Approved	Infra Platforms & Services	SAP CCS BACK OFFICE	CX&T-IT-Core App Platforms-SAP	200	34,096
243	2/28/2023	DMND0194460	enhancement	Updating pre-programmed customer segmentation on MPSC Gas Insert	Submitted		SAP CCS BACK OFFICE	Creative Services and Communications	-	-
244	2/28/2023	DMND0194461	enhancement	MPSC Bill Insert Waste Elimination on Second Copy Rebills	Submitted		SAP CCS BACK OFFICE	Creative Services and Communications	-	-
245	3/1/2023	DMND0194566	Enhancement	Unifier - Enhancements	Approved	Energy Combined	Unifier	Technology Portfolio Management	122	46,158
246	3/7/2023	DMND0194965	Enhancement	Sub-domain creation for Local Gov't Benchmarking pilot	Screening	Customer	IT CUST PROGRAMS - Transportat	CX&T-Product Innov Bus Pilots	-	-
247	3/8/2023	DMND0195023	Enhancement	AppCurr E&GS Unifier P6 upgrade	Approved	Energy Combined	Unifier	Technology Portfolio Management	1,211	156,877
248	3/8/2023	DMND0195103	enhancement	Form 1676 process and/or collection of 671 HPM & 676 Reg std	Submitted		SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
249	3/13/2023	DMND0195368	Enhancement	CONNECT PORTAL: Updates to Master Template for Provisioning Connect Sites	Qualified	Corporate	Connect	P&C-Workforce Planning & Analytics	28	2,076
250	3/20/2023	DMND0195715	Enhancement	Changes to Gas GIS Web Viewer	Qualified	Electric	GIS Web Locator and Viewer	GE&S/Gas Asset Information	63	5,824
251	3/21/2023	DMND0195825	Enhancement	ADMS - OMS Home	Approved	Electric	ADMS	Technology Portfolio Management	1,071	76,082
252	3/21/2023	DMND0195833	Enhancement	ADMS - Outage Apps (Storm Hub)	Approved	Electric	ADMS	Technology Portfolio Management	620	45,151
253	3/22/2023	DMND0195904	enhancement	Customizable Return Address for Certain Bills in SAP Batch Billing	Submitted		SAP CCS BACK OFFICE	OP-Product Implementation-II	-	-
254	3/24/2023	DMND0196012	enhancement	Auto Submission to DebtNext (180 file) once bankruptcy is removed from an accoun	Submitted		SAP CCS COLLECTIONS	CX&T-Revenue Ops & Assistance	-	-
255	3/27/2023	DMND0196096	Enhancement	OpenText - High Availability	Qualified	Infra Platforms & Services	OpenText Administration Client 1(	CX&T-IT-Core App Platforms-SAP	600	108,787
256	3/27/2023	DMND0196118	Enhancement	Tibco API Exchange Gateway Replacement	Qualified	App Platforms & Services	TIBCO ESB	Cx&T-IT-Enterprise Middleware	688	67,422
257	3/29/2023	DMND0196232	enhancement	Automation/Update of ZEOEMV SAP Transaction	Submitted		SAP CCS BACK OFFICE	CX&T-Quality & Data Systems	-	-
258	3/31/2023	DMND0196360	Enhancement	Sync Issues between Endeavor and SAP	Approved	Customer	SAP CCS BACK OFFICE	CX&T-IT-Contact Center and Digital Ops	888	45,657
259	4/10/2023	DMND0196779	enhancement	Sample data from service Suite for productivity report	Submitted		Service Suite	OP-Analytics Products	-	-
260	4/14/2023	DMND0197065	Enhancement	Extract data from Power BI Service	Qualified	Customer	Power BI	CXCO Customer Data Analytics	-	6,810
261	4/14/2023	DMND0197075	enhancement	IVR - authentication design change	Submitted		Genesys IVR	CX&T-Cust Ops Projects & Support	-	-
262	4/17/2023	DMND0197131	Enhancement	Add service type variable to T973 and T783	Screening	Corporate	SAP CCS BACK OFFICE	Creative Services and Communications	-	-
263	4/17/2023	DMND0197166	Enhancement	Update to CE.Com enrollment process for ACPC and H2O DR Programs	Approved	Customer	IT CUST PROGRAMS - Demand Sid	CX&T-Product Innov Bus Pilots	150	12,805
264	4/20/23	DMND0197381	Enhancement	Ebill and Outage files load testing for KUBRA upgrade	Approved	Customer	SAP CCS FRONT OFFICE	Rev Ops - Energy Assistance & Payment Pr	49	3,258
265	4/24/23	DMND0197483	Enhancement	Add the logic to ZSCR260_PCARD_TRANS to allow filtering of supervisor pern	Screening	Electric	SAP ERP FINANCE	WM&CD-SW Zone-BCK/COLD/HAS/MAR	125	9,928
266	4/24/23	DMND0197500	Enhancement	Automated process to validate results after SAP transports are imported.	Approved	App Platforms & Services	SAP	Cx&T-IT-SAP Dev Standards	1,718	57,641
267	4/26/23	DMND0197604	Enhancement	Add column to SQM survey file that is sent to SQM.	Approved	Customer	Genesys IVR	CX&T RP TECH	146	10,975
268	4/28/23	DMND0197681	Enhancement	Metadata Pull Automation	Approved	Customer	SAP CCS BACK OFFICE	Cx&T-IT-Cust-Rates Rev Gen & Collect	241	10,331
269	4/28/23	DMND0197689	Enhancement	Migrate legal files into legal file area in TIM.	Screening	Corporate	Total Information Management (E	DGC-Transactions & Employment	10	794
270	5/1/23	DMND0197736	Enhancement	Updating default task list under the Make Ready priority	Screening	Electric	SAP WORK ORDERS	Network Attachments	-	-
271	5/1/23	DMND0197746	enhancement	WE# 9878: Automate adding new operation to order	Submitted		SAP WORK ORDERS	GO-Gas Scheduling SE	-	-
272	5/1/23	DMND0197747	enhancement	Microsoft 365 External Third Party Sharing Request	Submitted		Real Estate Questions	Real Estate-Proj Controls	-	-
273	5/3/23	DMND0197817	enhancement	Create standard library of Powerpoint macros	Submitted			Corporate Strategy	-	-
274	5/4/23	DMND0197839	Enhancement	DocuSign OKTA Integration	Qualified	Corporate	DocuSign for Outlook	CX&T-IT-Corporate Product Family	-	16,047
275	5/5/23	DMND0197913	Enhancement	Add more MATs for Emplifi Customer Surveys	Qualified	Customer	SAP WORK MANAGEMENT	Cx&T-Customer Research	-	7,838
276	5/8/23	DMND0197981	enhancement	Need a way to identify repeat work orders in Endeavor	Submitted		SAP CCS FRONT OFFICE	CX&T-Home & Ind Mat Logistics & Inv Mgmt	-	-
277	5/9/23	DMND0198059	Enhancement	Legal Phone Collection Forensic Tool	Qualified	Corporate	Security	Cx&T-IT-CPF-Corporate Shared Products	1,719	66,203
278	5/10/23	DMND0198102	enhancement	Create Storm Responder Program Board "Circuit Restoration Coordinator"	Submitted		ADMS	Incident Management	-	-
279	5/16/23	DMND0198375	Enhancement	Link put into every sap order even emerg	Screening	Electric	Service Suite	EO-LVD-WEST-ZONE 5-BENZIE	-	-
280	5/18/23	DMND0198585	Enhancement	Request for Gas emergency over 60 minute flag in Service Suite	Screening	Gas	Service Suite	GO-Gas Dispatch SE A	60	4,765
281	5/18/23	DMND0198589	Enhancement	Comments should post to Wage or Absence type entries from a WAT entry in FSS	Qualified	Energy Combined	SAP WORK ORDERS	Operations Software & Technology	-	19,200

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Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Open Date	Number	Type	Description	State	Portfolio	Configuration Item	Requestor Department	Total Estimated Hours	Planned Cost
282	5/19/23	DMND0198655	Enhancement	GALT REL Order/MAT Type Change Request	Qualified	Gas	SAP WORK ORDERS	GO-Gas Distribution-North-Zone-2D	-	26,474
283	5/19/23	DMND0198656	Enhancement	Limiting Access to Gas Emergency Acknowledgements	Screening	Gas	Service Suite	GO-Gas Dispatch	-	-
284	5/19/23	DMND0198657	Enhancement	Add Headquarter to Dispatch Emergency Acknowledgement pop up in Service Suite	Screening	Gas	Service Suite	GO-Gas Dispatch NE	-	-
285	5/19/23	DMND0198661	enhancement	Automate timesheet premiums via Service Suite, SS/SAP Interface or SAP HR Module	Submitted		SAP WORK ORDERS	Operations Software & Technology	-	-
286	5/19/23	DMND0198691	Enhancement	GCCP DNV Inspection Manager Changes- Leak Tracking (Vendor Work)	Approved	Gas	Inspection Manager - GCC	GE&S/GAM/SI/DIMP-Reg Mgmt & DIMP Opt.	20	5,096
287	5/26/23	DMND0199008	Enhancement	Distribution Regulation enhancement for WAM with Inspection Manager	Screening	Gas	SAP WORK ORDERS	Go-Gas Dist-Regulation-Statewide	-	-
288	5/26/23	DMND0199015	enhancement	Create a Malfunction form in Service Suite	Submitted		Service Suite	GO-Gas Service-Southeast C4	-	-
289	5/26/23	DMND0199016	enhancement	MITS phase 2: Add "inspection pass or fail" field to C&I meter completion form	Submitted		SAP WORK ORDERS	GO-Gas Service-Southeast C4	-	-
290	5/26/23	DMND0199017	Enhancement	Phase 2 MITS Automation - Update maintenance plan on exchange/replace job	Screening	Gas	SAP WORK ORDERS	GO-Gas Service-Southeast C4	-	-
291	6/1/23	DMND0199093	Enhancement	Remove measle from gas new business order/mat types	Qualified	Gas	Service Suite	Technology Portfolio Management	-	13,200
292	6/6/23	DMND0199256	Enhancement	Build a report to send email to employees for 'In Process' timesheet recor	Approved	Corporate	SAP ERP PAYROLL	Payroll & Payroll Processing	538	16,919
293	6/6/23	DMND0199324	Enhancement	Create a workflow for new equipment requests/installs in data centers	Approved	Electric	ADMS	Technology Portfolio Management	371	29,585
294	6/7/23	DMND0199381	Enhancement	ConsumersEnergy.com Forestry Requests	Approved	Customer	Consumers Web Site	CX&T-Digital Operations	303	16,715
295	6/8/23	DMND0199424	enhancement	Disconnect/Reconnect p	Submitted		SAP CCS FRONT OFFICE	Exp Design Utility Services	-	-
296	6/13/23	DMND0199626	Enhancement	Excavators are not able to see the comments left by Gas Transmission locat	Screening	Gas	SAP WORK MANAGEMENT	OCC-Dam Prev & PSO	-	-
297	6/15/23	DMND0199804	Enhancement	Voluntary Green Pricing Programs Billing Automation - LCREP Automation	Approved	Customer	SAP CCS BACK OFFICE	Rates & Reg-Rate Administration	1,544	152,733
298	6/19/23	DMND0199896	Enhancement	ServiceNow form that would prompt CEVA to ask for printer detail	Approved	Infra Platforms & Services	ServiceNow	CX&T-IT-IP&S-IT Device Purch & Deploy	80	3,911
299	6/19/23	DMND0199900	enhancement	new 800s assigned for marketing initiatives	Submitted		Genesys IVR	CX&T SCC-CCC Policy & Procedures	-	-
300	6/23/23	DMND0200102	Enhancement	GAAP Financial Reporting Work for Controllers office	Qualified	Corporate	Power BI	CX&T-IT-Corporate Product Family	-	-
301	7/13/23	DMND0200724	Enhancement	TotSum (actual) field on SAP work order not populating	Screening	Gas	SAP WORK MANAGEMENT	GO-Gas Asset Reliability Management	-	-
302	7/20/23	DMND0201004	enhancement	Change Default Lock Reason in CRM from Assistance to Blank	Submitted		SAP CCS FRONT OFFICE	CX&T-CO Strategy Support	-	-
303	7/21/23	DMND0201061	Enhancement	LIMS - Update Citrix Procurement Request	Approved	Energy Combined	LIMS NDT	Technology Portfolio Management	38	3,060
304	7/26/23	DMND0201181	Enhancement	Current Occupant Discononection Document issues.	Qualified	Customer	SAP CCS FRONT OFFICE	DCO-Rev Ops-Credit Operations	212	13,520
305	7/26/23	DMND0201212	Enhancement	SAP Exception - Business Unit Invalid - Auto correction	Screening	Work Management	SAP WORK ORDERS	Operations Software & Technology	-	-
306	7/26/23	DMND0201213	enhancement	Gas leak orders modification needed	Submitted		SAP WORK MANAGEMENT	GO-Gas Service-Southeast A4	-	-
307	7/31/23	DMND0201309	Enhancement	Produce Detail of Estimates which ties to AMI Billable Orders Report	Qualified	Customer	SAP CCS BACK OFFICE	CX&T-Customer Billing B	102	6,155
308	7/31/23	DMND0201321	enhancement	Replace Auto Updater and Attribute Inheritance with Attribute Assistant in GIS	Submitted		SIMSWeb	GE&S/Gas Asset Info/Gas Distribution	-	-
309	8/3/23	DMND0201506	Enhancement	2023 Clarity Enhancement	Approved	Corporate	Clarity	Cx&T-IT-CPF-Corporate Shared Products	305	16,179
310	8/7/23	DMND0201585	Enhancement	ArcGIS Mobile Worker Licenses	Screening	Electric	ArcGIS	Electric GIS	-	-
311	8/7/23	DMND0201590	Enhancement	SAP/Field Service Suite changes to prevent ODR Sniff test erroneous submis	Qualified	Gas	SAP WORK MANAGEMENT	GE&S/GAM/SI/DIMP-Reg Mgmt & DIMP Opt.	-	56,962
312	8/15/23	DMND0201792	Enhancement	Notification accidental closure auto fix - Put in process when order is RWRK/RSC	Screening	Energy Combined	SAP WORK MANAGEMENT	Operations Software & Technology	-	-
313	8/16/23	DMND0201902	Enhancement	Utilize Citrix to publish applications - GIS WebViewer and CRM7	Approved	Electric	Citrix	CX&T-IT-S&G-Strategy E&A	26	2,139
314	8/22/23	DMND0202067	Enhancement	Wireless Connectivity support optimization	Approved	Energy Combined	WIRELESS	Technology Portfolio Management	55	44,924
315	8/22/23	DMND0202076	enhancement	New Query Project	Submitted		SAP CCS BACK OFFICE	IT-D&A Services-Data Architects	-	-
316	8/29/23	DMND0202414	Enhancement	LNDC order type, status profile updated	Qualified	Electric	SAP WORK MANAGEMENT	Real Estate-Proj Controls	109	7,216
317	8/30/23	DMND0202482	Enhancement	Update Workflow to eliminate daily EG32 Electric removal failures.	Screening	Work Management	SAP WORK ORDERS	EO-Smart Energy Operations A	-	-
318	8/30/23	DMND0202486	Enhancement	Power BI Extract for Server Refresh Status	Approved	Energy Combined	Business Object Client tools	OP-Agile Analytics II	130	7,295
319	8/30/23	DMND0202490	Enhancement	EMITS Improvement	Qualified	Energy Combined	SAP WORK MANAGEMENT	EO-Elec Meter Ops	-	100,000
320	8/31/23	DMND0202503	Enhancement	Create ability to log storm reason codes for Dispatch Back to Pending Acti	Qualified	Electric	SAP WORK ORDERS	EO-LVD-West	331	22,100
321	9/5/23	DMND0202571	enhancement	Police/Fire Hazard Dashboard ETA Functionality	Submitted		ADMS	Incident Management	-	-
322	9/5/23	DMND0202574	enhancement	Add a Further Action Box in the Referral Tab of the Mobile App of Service Suite	Submitted		SAP WORK MANAGEMENT	OP-Digital Products-I	-	-
323	9/5/23	DMND0202575	Enhancement	Update SAP Order Operations with "Not Needed" Option for Bore & Welding Op	Screening	Work Management	SAP WORK MANAGEMENT	WM&CD-SE Dist Sched South	-	-
324	9/5/23	DMND0202578	enhancement	Flag jobs referred back as "safety" so they are not sent out til issue is checke	Submitted		Service Suite	GO-Gas Service-Southeast C5	-	-
325	9/5/23	DMND0202579	enhancement	Waste Elimination: Remove or Reduce SAP Orders printing on the SHP in Dispatch	Submitted		SAP WORK MANAGEMENT	ED GM-LVD Dispatch-GR A	-	-
326	9/5/23	DMND0202583	enhancement	Gap was identified in CatCrewing having all of the WG and WE contact information	Submitted		Catastrophic Crewing - CatCrew	EO-Elec Meter Ops	-	-
327	9/14/23	DMND0202837	enhancement	Change "direct pay" wording on customer bills	Submitted		SAP CCS BACK OFFICE	Rev Ops - Energy Assistance & Payment Pr	-	-
328	9/21/23	DMND0203058	enhancement	Unifier - Actuals Integration with SAP	Submitted		Unifier	Technology Portfolio Management	-	-
329	9/28/23	DMND0203272	Enhancement	Smartops Work Automation	Qualified	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt	252	7,500
330	9/28/23	DMND0203283	Enhancement	Voxai - IVR changes to emergency menus	Screening	Customer	SAP CCS FRONT OFFICE	CX&T-Cust Ops Projects & Support	-	-
331	10/3/23	DMND0203365	Enhancement	Enable supervisors ability to edit employee timesheets in MSS 1470	Approved	Corporate	SAP ERP PAYROLL	CX&T-IT-CPF-P&C	531	62,818
332	10/3/23	DMND0203366	Enhancement	Mobile ESS 1470	Approved	Corporate	SAP ERP PAYROLL	CX&T-IT-CPF-P&C	1,118	156,580
333	10/5/23	DMND0203459	Enhancement	Legal Operations would like to explore software solutions for Legal Hold	Approved	Corporate	Legal Hold Pro	DGC-Litigation Practice Area	395	24,558
334	10/9/23	DMND0203513	enhancement	Add DLOC_GAS, DLOC_ELEC and DLOC_APPL to ES66 Device Location Transaction in SAP	Submitted		SAP WORK ORDERS	Distribution Engineering Office	-	-
335	10/9/23	DMND0203515	enhancement	FSS DA Manual Sequencing	Submitted		Service Suite	GO-GCON-Resource Mgmt- D	-	-
336	10/11/23	DMND0203555	enhancement	Changes needed to tcode ZSYNC OPERAND	Submitted		IT CUST PROGRAMS - Demand Sid	CX&T-IT-CEO-Proj Mgmt	-	-
337	10/12/23	375664	Enhancement	Implement Application Control in DMZ	Submitted	Security	Security	Security	300	187,500
338	10/12/23	375667	Enhancement	Encrypt USB - Removable Device Protection	Submitted	Security	Security	Security	100	32,500
339	10/12/23	375670	Enhancement	Test MDE for Andriod and IOS	Submitted	Security	Security	Security	100	12,500
340	10/12/23	375671	Enhancement	VDP (Vulnerability Disclosure Program) Database	Submitted	Security	Security	Security	100	12,500
341	10/12/23	375676	Enhancement	MDCA Managed Apps	Approved	Security	Security	Security	60	7,500
342	10/12/23	375679	Enhancement	Run Infection Monkey	Screening	Security	Security	Security	80	10,000
343	10/12/23	375681	Enhancement	Logging in Generation	Submitted	Security	Security	Security	400	85,000
344	10/12/23	375682	Enhancement	OT Server Hardening Process review	Submitted	Security	Security	Security	100	12,500
345	10/12/23	375683	Enhancement	OT Firewall/Switch Hardening Process Review	Submitted	Security	Security	Security	100	12,500
346	10/12/23	375686	Enhancement	Consider Explicit Deny Policy for Certain Services	Submitted	Security	Security	Security	80	10,000
347	10/12/23	375687	Enhancement	CIS Control 9.2 - DNS FIltering	Submitted	Security	Security	Security	80	10,000
348	10/12/23	375688	Enhancement	CIS 9.3 - Maintain and Enforce Network Based URL Filters	Submitted	Security	Security	Security	150	18,750
349	10/12/23	375689	Enhancement	CIS 8.12 - Collect Service Provider Logs	Submitted	Security	Security	Security	100	12,500
350	10/12/23	375690	Enhancement	CIS 9.5 - Implement DMARC/DKIM/SPF	Submitted	Security	Security	Security	100	12,500
351	10/12/23	375691	Enhancement	CIS 13.5 - Manage Access Control for Remote Assets	Submitted	Security	Security	Security	120	15,000
352	10/12/23	375692	Enhancement	CIS 2.5,2.6,2.7 - Allowlist Authorized Software, Allowlist Authorized Libraries, Allowlist Authorized Scripts	Submitted	Security	Security	Security	450	306,250
353	10/12/23	375793	Enhancement	STORM - Privacy Incident Tracking (Ticket/Workflow)	Submitted	Security	Security	Security	150	18,750
354	10/12/23	375795	Enhancement	Playbook to Sever CE Internet Connectivity	Approved	Security	Security	Security	150	18,750
355	10/12/23	375800	Enhancement	Island Protocol Playbook	Submitted	Security	Security	Security	180	22,500
356	10/12/23	375801	Enhancement	Assign Frequent Clicker Training	Submitted	Security	Security	Security	120	15,000
357	10/12/23	375802	Enhancement	KPMG Source Code Finding	Submitted	Security	Security	Security	150	18,750
358	10/12/23	375803	Enhancement	New Employee Playbook (NEP) Reporting Automation	Submitted	Security	Security	Security	480	60,000
359	10/12/23	375804	Enhancement	Improve Real Phishing Statics Tracking	Submitted	Security	Security	Security	160	20,000
360	10/12/23	375808	Enhancement	Remove OT Managed Non-Regulatory Devices From the Cyber Asset Library in SigmaFlow (Add to ServiceNow)	Submitted	Security	Security	Security	480	60,000
361	10/12/23	375810	Enhancement	Automate tagging of NERC CIP documents in SigmaFlow	Submitted	Security	Security	Security	480	60,000
362	10/12/23	375811	Enhancement	Automate People data being uploaded in the People Library	Submitted	Security	Security	Security	480	60,000
363	10/12/23	375814	Enhancement	CEVA STORM Automation Intake	Submitted	Security	Security	Security	120	15,000
364	10/12/23	375815	Enhancement	After Action Reports	Submitted	Security	Security	Security	480	60,000
365	10/12/23	375816	Enhancement	Emergency Managment Business Continuity Dashboard	Submitted	Security	Security	Security	160	20,000
366	10/18/23	DMND0203700	enhancement	Gateway Creation from SharePoint Online to Microsoft SQL Server	Submitted		Microsoft Power Apps (MSPA)	GE&S/GAM/SI-TIMP	-	-
367	10/24/23	DMND0203778	Enhancement	Agent Auto Assignment Module	Qualified	Infra Platforms & Services	ServiceNow	Deskside Support Jackson	106	5,163
368	10/25/23	379739	Enhancement	GP 6.2 - HIP Feature	Submitted	Security	Security	Security	80	10,000
369	10/25/23	379760	Enhancement	Microsoft DLP Enhancements (Phase 2)	Submitted	Security	Security	Security	480	60,000

Enhancement Worklist Detail
Information Technology
For Years 2016 Through October 21, 2024
($0)

Line No.	(a) Open Date	(b) Number	(c) Type	(d) Description	(e) State	(f) Portfolio	(g) Configuration Item	(h) Requestor Department	(i) Total Estimated Hours	(j) Planned Cost
370	11/6/23	DMND0203996	enhancement	Create database table, and automate P6 Milestone data, run weekly	Submitted		Primavera P6	EPM-Proj Controls Schedule-Gas Projects	-	-
371	11/6/23	DMND0204014	Enhancement	Create ServiceNow Email Interface to log an IT-to-IT Request	Qualified	Infra Platforms & Services	ServiceNow	Cx&T-IT-IAO-Database & PCTools	68	3,340
372	11/13/23	DMND0204200	enhancement	Update to the IVR message RO6050	Submitted		SAP CCS FRONT OFFICE	Customer Strategy Performance	-	-
373	11/13/23	DMND0204218	Enhancement	Create a PowerApp to request a work order for location property.	Approved	Corporate	SAP ERP POWERPLANT - TAX	General Accounting	1,830	138,098
374	11/27/23	DMND0204378	Enhancement	Emergent Work on improving the reliability and performance of the ISIS Pla	Approved	App Platforms & Services	ISIS	CX&T-IT-Enterprise Applications	4,668	359,229
375	11/29/23	DMND0204408	Enhancement	Prevent mischarging orders on manual time entry on service suite timesheets	Screening	Gas	Service Suite	GO-Gas Service-Southeast C4	-	-
376	11/29/23	DMND0204421	Enhancement	Create a flag in SAP for marking accounts with a PPA	Qualified	Work Management	SAP CCS BACK OFFICE	EO-Elec Meter Ops	-	-
377	12/5/23	DMND0204469	Enhancement	Enhance Workflow to stop duplicate meter stand orders created.	Qualified	Gas	SAP WORK MANAGEMENT	GO-Gas Service-Southeast C4	184	12,014
378	12/5/23	DMND0204476	Enhancement	Print GU LED and GUL on one invoice	Screening	Customer	SAP CCS BACK OFFICE	Rates & Reg-Rate Administration	-	-
379	12/5/23	DMND0204484	Enhancement	No Schema Extension errors - need to generate an emma case	Screening	Customer	SAP CCS BACK OFFICE	CX&T-Customer Billing B	-	-
380	12/6/23	DMND0204515	Enhancement	2024 MPSC Rate Changes	Approved	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt	7,492	449,811
381	12/14/23	DMND0204690	enhancement	TMD issue	Submitted		SAP CCS BACK OFFICE	EO-Smart Energy Operations B	150	11,913
382	12/19/23	DMND0204788	Enhancement	RNG Voluntary Program Billing Architecture	Approved	Customer	SAP CCS BACK OFFICE	CX&T-Residential Renewables	1,879	197,668
383	12/20/23	DMND0204797	enhancement	Environmental Work Orders to PowerBI	Submitted		eSOMS	Compliance/EMS	-	-
384	1/2/24	DMND0204862	Enhancement	AutoSol Upgrade	Qualified	GAS	AutoSol	CX&T-IT-S&G-Strategy E&A	-	-
385	1/3/24	396368	Enhancement	STORM 8 Migration	Submitted	Security	Security	Security	480	95,000
386	1/3/24	DMND0204877	Enhancement	Create a report of failures and success for ZEAM_IRTH_WORK_ITEM_UPLOAD	Screening	Gas	SAP WORK MANAGEMENT	OCC-Dam Prev & PSO	-	-
387	1/4/24	DMND0204909	enhancement	Shared Outlook or Teams Calender to share w/outside contractor	Submitted		MISSING CI	EO-Lines Const & Main South & West	-	-
388	1/8/24	DMND0204932	Enhancement	Gas Meter Set - Did you rebuild the stand	Screening	Gas	Service Suite	Cx&T-IT-Work and Asset Management	-	-
389	1/9/24	DMND0204961	Enhancement	Daily Cascade Timesheet Program for Success/Failure posting report	Screening	Gas	SAP TIMESHEET IDOCS	Cx&T-IT-Work and Asset Management	-	-
390	1/9/24	DMND0204990	enhancement	Add Battle Creek city-owned lights on SOAR map with city dpw number listed	Submitted		SAP CCS FRONT OFFICE	Exp Design Utility Services	-	-
391	1/10/24	DMND0205033	Enhancement	Fidelity Administration (Restricted Stock) moving from Equinity	Approved	Corporate	ZHRPYO_FIDELITY_DEMOG_OUTB	P&C HR Information Systems	1,131	118,030
392	1/11/24	DMND0205064	enhancement	Create a new Operand in SAP for PPAs	Submitted		SAP CCS BACK OFFICE	Wholesale Settlements	-	-
393	1/11/24	DMND0205119	Enhancement	Attachments viewed in CRM7 as well as SAP Back office even prior to orders FCMP	Screening	Electric	SAP WORK MANAGEMENT	EO-Elec Mtr Ops-Zone 7	-	-
394	1/17/24	DMND0205213	enhancement	GCCP 2024 Service Leak Survey - SRVY123 AGOL & DNV Import Tool Updates	Submitted		Inspection Manager - GCC	GE&S/GAM/SI/DIMP-Reg Mgmt & DIMP Opt.	-	-
395	1/23/24	DMND0205357	enhancement	C&I - Capital changes for 2024	Submitted		SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
396	1/24/24	DMND0205409	Enhancement	GRIP Grant SAP & Service Suite Changes	Qualified	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	294,182
397	2/1/24	DMND0205691	enhancement	Transition Complaints Team from Avaya phones to Genesys WDE SIP end point	Submitted		SAP CCS FRONT OFFICE	CX&T SCC-CCC Policy & Procedures	-	-
398	2/5/24	DMND0205708	Enhancement	FCS application from 4.5.3 to 4.6.2	Approved	Electric	Itron FCS	Technology Portfolio Management	1,005	67,771
399	2/5/24	DMND0205714	Enhancement	Upgrade eDNA	Approved	Gas	eDNA	Cx&T-IT-E&GS-OT-Critical Applications	87	5,472
400	2/5/24	DMND0205715	Enhancement	Upgrade Citect to latest supported version	Approved	Gas	OT AVEVA Historian	Cx&T-IT-E&GS-OT-Critical Applications	124	7,802
401	2/5/24	DMND0205730	Enhancement	Upgrade Aveva PI to 2018 SP3	Approved	Gas	PI EDH	Cx&T-IT-E&GS-OT-Critical Applications	417	26,248
402	2/6/24	DMND0205743	enhancement	PIR/PID link to be resent to accounts after MIMO	Submitted		SAP CCS FRONT OFFICE	CX&T-IT-Contact Center and Digital Ops	-	-
403	2/6/24	DMND0205745	Enhancement	2 ideas - ZEAMRMITS and Pulse Constant	Qualified	Electric	Service Suite	EO-Elec Mtr Ops-Zone 7	143	21,514
404	2/12/24	DMND0205927	Enhancement	Need to Modify CAP Report	Approved	Customer	SAP CCS BACK OFFICE	CX&T BCC-Bus Solutions	18	1,997
405	2/15/24	DMND0206010	Enhancement	Add middle initial to names within Riskonnect BC&R Application	Qualified	Corporate	ServiceNow	Emergency Mgmt & Public Safety	25	1,232
406	2/19/24	DMND0206114	Enhancement	Foglight Upgrade for 2024	Approved	App Platforms & Services	FogLight for Oracle - DBA	CX&T-IT-Core App Platforms-SAP	239	28,800
407	2/19/24	DMND0206115	Enhancement	RMAN and OEM Upgrade for 2024	Approved	App Platforms & Services	DOEMP020@prmlnx0129	CX&T-IT-Core App Platforms-SAP	218	25,920
408	2/19/24	DMND0206128	Enhancement	Implement ServiceNow - Service Graph Connector for Runzero	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	134	6,571
409	2/20/24	DMND0206129	Enhancement	SAP Planning Plant Table Update Needed	Qualified	Gas	SAP WORK MANAGEMENT	OCC-Dam Prev & PSO	-	6,660
410	2/20/24	DMND0206148	Enhancement	Azure OpenAI Non-Prod and Prod Landscapes	Qualified	App Platforms & Services	CE-Azure-Prod	Cx&T-IT-Development Standards	1,642	96,259
411	2/20/24	DMND0206168	enhancement	Time Approval (MSS) Facelift and Performance	Submitted		SAP ESS/MSS	CX&T-IT-CPF-P&C	-	-
412	2/20/24	DMND0206171	enhancement	Time Entry (ESS) Facelift and Performance	Submitted		SAP ESS/MSS	CX&T-IT-CPF-P&C	-	-
413	2/20/24	DMND0206178	Enhancement	Update bypass completion automation for GMTR RPL and GMTR NBM orders	Screening	Gas	SAP WORK MANAGEMENT	GO-Gas Service-Southeast C4	-	-
414	2/21/24	424472	Enhancement	PAM Program Maturation: Discovery (ce.corp.com, DMZ.cms, and corp.com)	Submitted	Security	Security	Security	200	37,000
415	2/21/24	DMND0206190	Enhancement	7202 - Automating A2-s into GCon Property Restoration	Qualified	Gas	GCON Property Restoration	Cx&T-IT-Work and Asset Management	453	72,892
416	2/22/24	425504	Enhancement	Vulnerability Management Data in the Lake	Submitted	Security	Security	Security	80	10,000
417	2/26/24	DMND0206377	Enhancement	573 Enlighta Remediation	Approved	Electric	Enlighta Govern	CX&T-IT-S&G-Strategy E&A	878	53,982
418	2/26/24	DMND0206378	Enhancement	Create an application to track MISS DIG Concerned Caller requests	Screening	Gas	SAP WORK MANAGEMENT	OCC-Dam Prev & PSO	-	-
419	2/27/24	DMND0206413	Enhancement	Natural Gas Outage Tag option in SAP for CSR.	Qualified	Gas	SAP WORK MANAGEMENT	GO-Gas Service-Southwest A1	-	58,233
420	2/28/24	DMND0206484	Enhancement	Power Platform Improvements	Qualified	App Platforms & Services	Microsoft Power Apps (MSPA)	Cx&T-IT-Development Standards	-	72,365
421	2/29/24	DMND0206550	Enhancement	Mobile App General O&M (not related to capital release work)	Approved	Customer	N/A	CX&T-Digital Operations	20	40,000
422	3/1/24	DMND0206577	enhancement	FACTA Automation	Submitted		CRM7	CX&T-IS-Revenue Assurance Fraud	-	-
423	3/4/24	DMND0206616	Enhancement	Automation of CSR time sheets	Approved	Customer	Genesys Framework	CX&T-Cust Ops Projects & Support	770	35,000
424	3/6/24	DMND0206682	enhancement	CE Tools - Dimension change	Submitted		CE Tools	Technology Portfolio Management	-	-
425	3/7/24	DMND0206714	Enhancement	Add CISA KEV References to SNVR Module	Qualified	Security	ServiceNow	CX&T-Security-Security Infra & Delivery	182	8,918
426	3/8/24	DMND0206764	enhancement	Modify ZBI_TOU_REPORT parameters for monthly TOU Report performed manually curre	Submitted		SAP CCS BACK OFFICE	CX&T-Customer Billing B	-	-
427	3/8/24	DMND0206781	enhancement	Bill message needs added to the bill when an interim read is present	Submitted		SAP CCS BACK OFFICE	CX&T-Customer Billing Res	-	-
428	3/12/24	DMND0206835	enhancement	Data Needed for U-20959	Submitted		SAP CCS BACK OFFICE	CXCO Customer Data Analytics	-	-
429	3/14/24	DMND0206927	Enhancement	Oracle Java to Azul Java Migration	Approved	Infra Platforms & Services	Windows7 Java	CX&T-IT-Core App Platforms-SAP	4,928	342,433
430	3/18/24	438036	Enhancement	Beacon	Submitted	Security	Security	Security	160	35,000
431	3/18/24	DMND0206963	Enhancement	Implement New Personalization Rules	Qualified	Customer	Consumers Web Site	CX&T-Digital Operations	92	5,151
432	3/19/24	DMND0206979	enhancement	Streetlight self service - ability for customers to see status when notification created in SAP	Submitted		SAP CCS FRONT OFFICE	CX&T - Experience & Portfolio Performanc	-	-
433	3/20/24	DMND0207051	Enhancement	SNOW License Manager Decommission	Approved	Corporate	Snow License Manager	CX&T-IT-Corporate Product Family	127	8,955
434	3/21/24	DMND0207086	enhancement	Add new entities (Branch, Genesse, Lake Iris) to the consol hierarchy and SAP	Submitted		SAP ERP FINANCE	Consolidated Accounting	-	-
435	3/28/24	441115	Enhancement	CSIRT POBOX Monitoring and Ticket Generation	Submitted	Security	Security	Security	60	7,500
436	4/1/24	DMND0207280	enhancement	New brand font pushed to all employees	Submitted		Microsoft Office	Brand & Creative Services	-	-
437	4/1/24	DMND0207292	enhancement	SAP New Postcard - Undergrounding	Submitted		CRM7	Creative Services and Communications	-	-
438	4/2/24	DMND0207345	Enhancement	SAP unassigned staking orders	Qualified	Gas	SAP WORK MANAGEMENT	GE&S-Damage Prev West	160	14,940
439	4/4/24	DMND0207416	Enhancement	P6 - Data Table	Approved	Electric	Primavera P6	Technology Portfolio Management	88	5,451
440	4/5/24	DMND0207456	Enhancement	MyEnergyXpertPilot	Approved	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt	270	16,872
441	4/5/24	DMND0207461	Enhancement	ServiceNow ITOM Health - Deploy an Automated End-to End Ops Workflow	Qualified	Corporate	ServiceNow	Cx&T-IT-IP&S-Monitoring	339	123,556
442	4/9/24	444595	Enhancement	Sensitive (medium risk) data detection in email	Submitted	Security	Security	Security	80	10,000
443	4/9/24	444598	Enhancement	Automate Bi-weekly Vendor Access Review	Submitted	Security	Security	Security	400	50,000
444	4/10/24	DMND0207592	Enhancement	Aligne Fuels - Upgrade	Approved	Electric	Fuel Management System (FMS)	Technology Portfolio Management	125	9,821
445	4/10/24	DMND0207613	Enhancement	Online W2 - Payroll Automation	Approved	Corporate	SAP ERP PAYROLL	P&C HR Information Systems	339	48,523
446	4/11/24	DMND0207624	enhancement	New SAP-Business Reporting Needs for Mandated MPSC Reporting Changes	Submitted		reporting	CXCO Customer Data Analytics	-	-
447	4/11/24	DMND0207634	Enhancement	Virtual Proctoring	Screening	Electric	Gas Operator Qualification	CX&T-IT-S&G-Strategy E&A	-	-
448	4/15/24	DMND0207724	Enhancement	App Currency - WinEst	Approved	Electric	Winest	Technology Portfolio Management	120	9,467
449	4/16/24	DMND0207727	Enhancement	App Currency - LIMS	Approved	Electric	LIMS Chemistry	Technology Portfolio Management	60	5,229
450	4/16/24	DMND0207755	Enhancement	Saviynt Integration with ServiceNow for NERC CIP Compliance	Qualified	Security	ServiceNow	CX&T-Security-Identity Orchestration	146	7,118
451	4/23/24	DMND0207901	Enhancement	Credential Check and SuccessFactor Integration	Approved	Corporate	Workforce Connect (SuccessFacto	P&C HR Technologies	51	5,365
452	4/24/24	DMND0207932	Enhancement	Mass Order Creation SAP Transaction Modification	Screening	Work Management	SAP WORK MANAGEMENT	EO-Smart Energy Operations B	-	-
453	4/25/24	DMND0207999	Enhancement	Planning Group Field, FSS Communication Loop w/ SAP	Qualified	Work Management	SAP WORK MANAGEMENT	EO-Forestry HVD/T&S Inspec&Work Plan	-	7,352
454	4/26/24	DMND0208033	Enhancement	New Integration from SAP to MarketPay	Approved	Corporate	MarketPay	P&C HR Information Systems	435	63,213
455	4/29/24	DMND0208062	Enhancement	Maintain Link Data between Service Suite and SAP Work Order	Qualified	Gas	SAP WORK ORDERS	Cx&T-IT-Work and Asset Management	-	70,109
456	4/30/24	DMND0208109	Enhancement	Gas Leak automated Order creation	Approved	Work Management	SAP WORK MANAGEMENT	OP-Software Products	2,521	176,011
457	5/2/24	DMND0208154	enhancement	Update to My Location/Searched Address marker in SOAR and Map Legend	Submitted		Azure DevOps	Exp Design Utility Services	-	-
458	5/3/24	DMND0208182	Enhancement	Workstation OS Upgrade	Approved	Infra Platforms & Services	Windows 11	CX&T-IT-IP&S-Client Productivity & Comp	415	29,113
459	5/6/24	458172	Enhancement	Validate defender app connectors and if we can enable	Screening	Security	Security	Security	20	2,500
460	5/7/24	DMND0208230	Enhancement	PowerClerk & Paymentus Integration	Qualified	Electric	SAP CCS COLLECTIONS	Distribution Agreements & Programs	532	30,863
461	5/7/24	DMND0208244	Enhancement	SAPGUI upgrade to v800 and latest patch	Approved	App Platforms & Services	SAP GUI - BASIS	CX&T-IT-Core App Platforms-SAP	1,360	107,000
462	5/10/24	DMND0208329	enhancement	Update the third party damage form that is created is FSS	Submitted		MISSING CI	GE&S-Damage Claims	-	-

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Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Open Date	Number	Type	Description	State	Portfolio	Configuration Item	Requestor Department	Total Estimated Hours	Planned Cost
463	5/13/24	1337456893	Enhancement	Landlord Portal – Entire new solution	Screening	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt		819,500
464	5/13/24	1337456895	Enhancement	High bill/inability to pay automation	Screening	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt		983,400
465	5/13/24	1337456905	Enhancement	Web Dashboard Redesign	Screening	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt		819,500
466	5/13/24	1337456911	Enhancement	Low/Moderate Income Enhancements	Screening	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt		819,500
467	5/13/24	1337252489	Enhancement	Mobile App Enhancements	Submitted	Customer	SAP CCS FRONT OFFICE-old	CX&T-Digital Operations		2,121,000
468	5/13/24	460464	Enhancement	Automation for SSO to see expiring certs	Submitted	Security	Security	Security	100	12,500
469	5/13/24	460467	Enhancement	OT ISE SigmaFlow Scanning	Approved	Security	Security	Security	120	15,000
470	5/13/24	DMND0208410	Enhancement	Make updates/changes to the Theft Form in FSS	Screening	Customer	Service Suite	CX&T-RO Credit & Collection	-	-
471	5/14/24	1337856946	Enhancement	Functional Enhancements to QTD and move it to the Cloud - Quality Training Database	Screening	Electric		Electric		366,100
472	5/14/24	1337856991	Enhancement	Functional & Config Enhancements for ADMS (e.g. DMS 10)	Screening	Electric	ADMS	Electric		409,750
473	5/14/24	1337857001	Enhancement	Enhancements to various Outage Applications	Screening	Electric	Outage Management System - ON	Electric		338,500
474	5/14/24	DMND0208425	Enhancement	Welder Qualification DB - Upgrade	Approved	Electric	Welder Qualification System (WQ	Technology Portfolio Management	86	7,361
475	5/14/24	DMND0208448	Enhancement	Please assign to Power Automate Team - Custom API Connector	Qualified	Customer	SAP PERSONAS FACILITIES PANEL	Field Operations Support A	-	90,035
476	5/14/24	DMND0208459	Enhancement	Unifier - Connector from Power Apps Enhancement	Approved	Electric	Microsoft Power Apps (MSPA)	Technology Portfolio Management	92	7,958
477	5/15/24	DMND0208506	enhancement	Please create meter reading route numbers (MRUS) that do not exist in SAP	Submitted		SAP CCS BACK OFFICE	Operations Software & Technology	-	-
478	5/15/24	DMND0208523	Enhancement	eSOMs mobile rounds - Covert	Qualified	Electric	eSOMS	Covert Operations	-	9,345
479	5/17/24	DMND0208600	Enhancement	Gas Measurement enhancement - AutoSol	Approved	App Platforms & Services	AutoSol	Cx&T-IT-E&GS-PlanningScheduling&MeterTec	1,684	115,558
480	5/21/24	DMND0208689	Enhancement	Customer Picture Capture Enhancement	Screening	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
481	5/21/24	463764	Enhancement	Azure Front Door conversion	Submitted	Security	Security	Security	150	18,750
482	5/22/24	1393257100	Enhancement	Enhancements for small changes and improvements to existing software to address requests needed due to changing business requirements.	Screening	Infra Platforms & Services	N/A	Cx&T-IT-IP&S-Monitoring		485,959
483	5/22/24	463781	Enhancement	Security Co-Pilot and Jamf	Submitted	Security	Security	Security	40	5,000
484	5/22/24	DMND0208739	Enhancement	CYME Upgrade Project	Approved	Electric	CYME	Electric Grid Models	556	26,392
485	5/23/24	DMND0208771	Enhancement	DevonWay - Module Updates	Approved	Electric	DevonWay	Technology Portfolio Management	1,361	78,838
486	5/28/24	DMND0208797	Enhancement	Remove the measle for bar testing from 2 new business gas order mat/types	Qualified	Gas	Service Suite	OCC-Standards Adherence & Verification	30	5,539
487	5/29/24	DMND0208820	Enhancement	GenPortal - Enhancement	Qualified	Electric	Generation Portal	Technology Portfolio Management	-	9,014
488	5/29/24	DMND0208836	Enhancement	PCI Insights Software	Screening	Electric	PowerCosts (PCI) GenTrader	Wholesale Settlements	-	-
489	6/4/24	DMND0208922	enhancement	Cost of Dataverse	Submitted		Azure Data Lake	GE&S Gas Compliance and Audit	-	-
490	6/6/24	DMND0208986	enhancement	Gas Opt Out Fee to be added when GCM is updated out on gas only accounts	Submitted		SAP CCS BACK OFFICE	CX&T SCC-CCC Policy & Procedures	-	-
491	6/6/24	DMND0209000	Enhancement	SCCM Application Lifecycle Management	Approved	Infra Platforms & Services	Microsoft SCCM	CX&T-IT-IP&S-Client Productivity & Comp	192	14,330
492	6/6/24	DMND0209001	Enhancement	Windows Security Tool Application Lifecycle Management	Approved	Infra Platforms & Services	Microsoft SCCM	CX&T-IT-IP&S-Client Productivity & Comp	147	10,294
493	6/7/24	473175	Enhancement	Entra ID Conditional Access - Customize continuous access evaluation	Screening	Security	Security	Security	20	2,500
494	6/7/24	473196	Enhancement	Enable - Entra ID token-protection	Screening	Security	Security	Security	20	2,500
495	6/11/24	473752	Enhancement	Automation - Palo Alto Device States + Monitoring	Submitted	Security	Security	Security	80	10,000
496	6/11/24	474059	Enhancement	Duo proxy URL	Screening	Security	Security	Security	80	10,000
497	6/12/24	DMND0209117	Enhancement	New catalog request form needed for cellular activations	Qualified	Infra Platforms & Services	ServiceNow	CX&T-IT-IP&S-IT Device Purch & Deploy	87	4,244
498	6/13/24	DMND0209126	Enhancement	App Currency - ArcMap	Approved	Electric	ArcFM	Technology Portfolio Management	54	4,432
499	6/13/24	DMND0209128	Enhancement	App Currency - ArcGIS Mobile (ESRI Field Apps)	Approved	Electric	ArcGIS Mobile	Technology Portfolio Management	205	15,681
500	6/14/24	1393357040	Enhancement	Move Redwood environments to vendor SaaS solution	Screening	App Platforms & Services	Redwood	CX&T-IT-Enterprise Applications		133,750
501	6/14/24	1393357042	Enhancement	Retire OT Datacenter Hyper-V virtualization clusters; migrate workloads to VxRail	Screening	App Platforms & Services	OT	OT Platforms		107,000
502	6/14/24	1393357080	Enhancement	Biztalk Retirement and Migration	Screening	App Platforms & Services	Biztalk	CX&T-IT-Enterprise Applications		686,940
503	6/14/24	1337257014	Enhancement	Develop parallel processes and tooling to support mutliple delivery paths for project and product delivery, inclusive of Change Management Process Redesign/Retooling for SOX delivery efforts. With the direction to have some teams in ADO and others in ServiceNOW we need extra tooling to support both paths.	Screening	Corporate	ADO	Cx&T-IT-S&G-ASDO		237,100
504	6/14/24	1337257019	Enhancement	Improve the ServiceNow Platform and capabilities such as cyber ark integration, Unified Portal, Operations Workspace and AI.	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		260,200
505	6/14/24	1337252420	Enhancement	Update the API to include Org, Middile Initial, phone	Screening	Corporate	Everbridge	Emergency Management		7,490
506	6/14/24	1337257019	Enhancement	Updates and improvements to PowerBI & Data Lake	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		10,700
507	6/14/24	1337257020	Enhancement	RunZero Service Graph Connector – One time cost of internal ServiceNow team to install: $15,000	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		15,000
508	6/14/24	1337257024	Enhancement	Go Mobile with ServiceNow modules – Utilize mobile features from ServiceNow (once our subscription is updated to do so)	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		5,000
509	6/14/24	1337257027	Enhancement	ServiceNow IT Operations Management (ITOM) Digital Employee Experience (DEX) Subscriptions and associated Agent Client Connection (ACC) implementation	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		80,250
510	6/14/24	1337357035	Enhancement	ServiceNow OTM - improve OT asset inventory data in relationship to production processes and providing services	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		80,250
511	6/14/24	1337256667	Enhancement	ServiceNow OTSM – Technology Implementation	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		333,150
512	6/14/24	1337256668	Enhancement	ServiceNow APIs for OT – APIs between ServiceNow and Vendors	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		107,000
513	6/14/24	1337256669	Enhancement	ServiceNow demands related to administrative maintenance	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		10,700
514	6/14/24	1337256669	Enhancement	ServiceNow SAM Pro and related integrations Workflow Enhancements and Automations	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		53,000
515	6/14/24	1337256670	Enhancement	Enhancements/automations for systems, integrations related to Enlighta retirement	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		10,700
516	6/14/24	1337256671	Enhancement	CAM ServiceNow Decommissioning workflow enhancement	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		5,350
517	6/14/24	1337257063	Enhancement	Data model for financial data reporting, sifting and scraping current SAP, PowerPlan, etc. to populate the lake, and creation of multiple reports from the lake.	Screening	Corporate		IT Finance		459,600
518	6/14/24	1337252421	Enhancement	Ability to capture forensic phone collections accurately as required by legal requests	Screening	Corporate		IT Legal		153,200
519	6/14/24	DMND0209180	enhancement	Gas/Electric Choice rate changes is removing opt out flag	Submitted		SAP CCS BACK OFFICE	CX&T SCC-CCC Policy & Procedures	110	8,736
520	6/14/24	DMND0209181	Enhancement	ServiceNow_OT_SGCs - BCSI data	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	177	8,636
521	6/14/24	DMND0209209	Enhancement	ServiceNow_OT_SGCs - NO BCSI data	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	339	16,564
522	6/14/24	DMND0209210	Enhancement	Create new Priority for ESIC work order type and new C1 Notification Code.	Qualified	Corporate	SAP WORK MANAGEMENT	BP&A-Gas Opns & Engg	329	20,282
523	6/18/24	DMND0209273	Enhancement	GCCP DNV Inspection Manager Changes	Approved	Gas	Inspection Manager - GCC	GE&S/GAM/SI/DIMP-Reg Mgmt & DIMP Opt.	35	26,013
524	6/19/24	DMND0209296	Enhancement	New Consent form changes in SAP	Approved	Customer	CRM7	CX&T SCC-CCC Policy & Procedures	1,008	92,000
525	6/19/24	DMND0209280	Enhancement	Reconciling Capital Charges before Field Completing Work Order	Screening	Electric	SAP WORK ORDERS	Lean - Elec Supply & Corp	-	-
526	6/21/24	478585	Enhancement	OT Assets RSA MFA Verification	Submitted	Security	Security	Security	120	15,000
527	6/24/24	DMND0209353	enhancement	Aurora CLM - Whitelisting	Submitted		AURORA	Technology Portfolio Management	-	-
528	6/24/24	DMND0209362	Enhancement	App Currency: WECO WATT-NET	Approved	Electric	WECO WinBoard Interface	Technology Portfolio Management	123	9,122
529	6/24/24	DMND0209386	Enhancement	Automating Doc Warehouse creation and sent the URL to SPIDA	Screening	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
530	6/24/24	DMND0209390	Enhancement	Sending Error log to SPIDA for the Notification creation failure	Screening	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
531	6/24/24	DMND0209391	Enhancement	SPIDA-SAP: Send Notification long Text to SPIDA and Work Order Integration	Screening	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
532	6/25/24	DMND0209424	Enhancement	Review Onyx ecoPitch SAAS & sensors	Approved	Electric	ONYX	Cx&T-IT-Gen Ops & Electric Work Mgmnt	114	7,893
533	6/25/24	DMND0209427	Enhancement	Changing 3 SAP V5 fields from optional to required entries in the field.	Screening	Customer	Service Suite	GE&S-Damage Claims Billing	-	-
534	6/25/24	DMND0209451	enhancement	Storm digital ad automation	Submitted		Storm Information MSPA	Brand & Creative Services	-	-
535	6/26/24	DMND0209457	Enhancement	Re-establish validation check between SAP Interface & MISS DIG EOD Reports	Screening	Gas	SAP WORK MANAGEMENT	OCC-Dam Prev & PSO	-	-
536	6/26/24	DMND0209501	Enhancement	SAP/Service Suite needs the backup LCP listed	Qualified	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	67,473
537	6/27/24	DMND0209508	Enhancement	Radio system enhancement for Barry County	Approved	Infra Platforms & Services	800 MHz IMC	Cx&T-IT-IP&S-Wireless Connectivity	91	152,898
538	6/27/24	DMND0209511	Enhancement	SAP Field Complete Status	Screening	Work Management	SAP WORK MANAGEMENT	Lean - Elec Supply & Corp	-	-
539	6/27/24	DMND0209512	Enhancement	Radio system enhancement for Calhoun County	Approved	Infra Platforms & Services	800 MHz IMC	Cx&T-IT-IP&S-Wireless Connectivity	97	161,623
540	6/28/24	480335	Enhancement	Prevent Regular users from enumerating elevated groups	Screening	Security	Security	Security	80	10,000
541	6/28/24	DMND0209552	Enhancement	Reinstation the Standish planning plant	Screening	Gas	SAP WORK MANAGEMENT	GO-Gas Dispatch NE	-	-
542	6/28/24	DMND0209553	Enhancement	Reallocation or creation of a Planning Plant for the Caro HQ	Screening	Gas	SAP WORK MANAGEMENT	GO-Gas Dispatch NE	-	-

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Line No.	(a) Open Date	(b) Number	(c) Type	(d) Description	(e) State	(f) Portfolio	(g) Configuration Item	(h) Requestor Department	(i) Total Estimated Hours	(j) Planned Cost
543	7/2/24	DMND0209613	Enhancement	New Integration from SAP to JDMS	Screening	Corporate	JDMS - Job Descriptions Made Sim	P&C HR Information Systems	-	-
544	7/8/24	DMND0209696	Enhancement	MTC New Machine (DTS-II) SAP Integration	Screening	Work Management	SAP QM	EPM-Electric T&D Project Management	-	-
545	7/9/24	DMND0209724	Enhancement	Replace WAVE/WEDB tool with PowerApp	Approved	Electric	Microsoft Power Apps (MSPA)	CX&T-IT-S&G-Strategy E&A	1,123	73,153
546	7/10/24	DMND0209732	enhancement	Create Service Objects for IH01 order create	Submitted		SAP WORK ORDERS	ED GM-LVD Dispatch-GR A	-	-
547	7/12/24	DMND0209815	Enhancement	Requiring users to provide information in Required fields	Approved	App Platforms & Services	ServiceNow	Cx&T-IT-S&G-ASDO	78	3,833
548	7/12/24	DMND0209816	Enhancement	Charm must be in "Successfully tested" or "Imported to preprod" before App	Approved	App Platforms & Services	ServiceNow	Cx&T-IT-S&G-ASDO	70	3,422
549	7/12/24	DMND0209824	Enhancement	Demand Ticket to support Uplight UDP work - Carmen Ryan IT contact	Approved	Customer	Energy Usage Dashboard	Exp Design Utility Services	247	29,477
550	7/15/24	DMND0209864	Enhancement	Add Word Order Description to 1ph 400 amp electric meter material	Screening	Electric	Service Suite	EO-Elec Mtr Ops-Zone 7	-	-
551	7/16/24	DMND0209889	Enhancement	SCCM High Availability Enhancement	Approved	Infra Platforms & Services	Microsoft SCCM	CX&T-IT-IP&S-Client Productivity & Comp	91	7,227
552	7/17/24	DMND0209900	enhancement	DPO Receipt Printers/Check Scanner Testing and Install	Submitted		PC76180	DCO RO-Direct Payment Offices-North/East	-	-
553	7/18/24	DMND0209960	Enhancement	Update CRM and order management	Approved	Customer	CRM7	CX&T SCC-CCC Policy & Procedures	766	59,947
554	7/22/24	DMND0209990	Enhancement	Cisco Field Network Director	Approved	Security	Cisco IoT Field Network Director (I	Technology Portfolio Management	343	21,637
555	7/22/24	DMND0209992	Enhancement	Cisco IOS	Approved	Security	Cisco Identity Services Engine	Technology Portfolio Management	288	18,164
556	7/23/24	DMND0210046	Enhancement	Update SAP order processing to allow for multiple responses within LAS/DAS	Qualified	Gas	SAP WORK MANAGEMENT	GO-Gas Service-Southeast B	-	37,369
557	7/24/24	DMND0210063	Enhancement	Set up Magnit VMS integration with ServiceNow via OOTB Spoke	Approved	Corporate	ServiceNow	P&C-Workforce Planning & Analytics	118	5,789
558	7/24/24	DMND0210071	Enhancement	Website LMI Program Enrollment	Screening	Customer	Consumers Web Site	CX&T-Digital Operations	-	-
559	7/24/24	DMND0210072	Enhancement	Renewable Program Online Enrollment	Approved	Customer	Sitecore	CX&T-Digital Operations	863	90,206
560	7/29/24	491368	Enhancement	SOX UAM 7 / 2.2 - Control Automation Improvement	Submitted	Security	Security	Security	100	12,500
561	7/29/24	DMND0210127	Enhancement	Service Suite Changes to the Lawn and Hard Surface Restoration Form	Screening	Gas	Service Suite	GO-GCON-Resource Mgmt- D	-	-
562	7/31/24	DMND0210264	Enhancement	Implement SAP integration for process currently using pen and paper.	Screening	Electric	SAP QM	EO-MTC Lifecycle Assessment	-	-
563	7/31/24	DMND0210266	enhancement	Update WattNet system.	Submitted		WattNet	EO-MTC Lifecycle Assessment	-	-
564	8/2/24	DMND0210326	Enhancement	Update in_HR_ESRV_ServiceNow_1070_Positions to include Update action	Screening	Corporate	SAP ERP HR	P&C-Workforce Planning & Analytics	-	-
565	8/5/24	DMND0210343	Enhancement	Rate Card Automation/Integration Between Clarity & Magnit	Approved	Corporate	Clarity	CX&T-IT-CPF-P&C	372	64,637
566	8/5/24	DMND0210355	enhancement	Update BP enrollment email to match mailed letter	Submitted		SAP CCS PAYMENT PLANS	Rev Ops - Energy Assistance & Payment Pr	-	-
567	8/6/24	DMND0210438	Enhancement	Implement ServiceNow Oracle Global License Advisory Services data collecti	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	40	1,968
568	8/7/24	DMND0210441	Enhancement	Need response added to SAP for end user on failure to report a no light to OMS	Screening	Electric	SAP WORK MANAGEMENT	GM-Products & Reporting	-	-
569	8/7/24	DMND0210477	Enhancement	Upgrade Singlestore to a supported version	Approved	Infra Platforms & Services	MemSQL Database	CX&T-IT-Core App Platforms-SAP	122	8,400
570	8/8/24	DMND0210494	Enhancement	CVR - DOE Enhancements	Approved	Electric	CVR Analytics	Technology Portfolio Management	684	43,436
571	8/9/24	DMND0210523	Enhancement	new chat GPT for contact center	Approved	Customer	ServiceNow	CX&T SCC-CCC Policy & Procedures	668	132,000
572	8/12/24	DMND0210548	Enhancement	Sales Tax Exemption Process Automations	Screening	Customer	CRM7	CX&T BCC-Bus Solutions	1,400	111,188
573	8/13/24	DMND0210550	enhancement	Solar Investigate Notification from CRM UI	Submitted		SAP CCS FRONT OFFICE	Distribution Agreements & Programs	-	-
574	8/13/24	DMND0210567	Enhancement	safety banner on en route screen going away when on site.	Screening	Gas	SAP WORK MANAGEMENT	GO-Gas Distribution-East-Zone-2B	-	-
575	8/13/24	DMND0210578	enhancement	BriefCatch add-in renewal and move from standalone to Microsoft 365 Admin	Submitted		BriefCatch 2.2 for Microsoft Office	Cx&T-IT-CPF-Corporate Shared Products	-	-
576	8/16/24	DMND0210628	Enhancement	Work Planning Dashboards for Various Stakeholders	Qualified	Gas	SAP WORK MANAGEMENT FINAN	Cx&T-IT-Work and Asset Management	1,834	198,930
577	8/18/24	DMND0210638	Enhancement	Register Update /Device Modification During Rate Transition Process	Approved	Customer	SAP CCS RATES	Cx&T-IT-Cust-Rates Rev Gen & Collect	702	74,060
578	8/19/24	DMND0210639	Enhancement	App Currency - CMM database upgrade	Approved	Electric	Synergi Gas CMM Customer Mana	Technology Portfolio Management	192	13,886
579	8/19/24	DMND0210663	Enhancement	CRM move out changes	Approved	Customer	CRM7	CX&T SCC-CCC Policy & Procedures	321	18,000
580	8/23/24	DMND0210866	Enhancement	Implement ServiceNow Certificate Management - Specifically Requesting a ne	Qualified	Security	ServiceNow	CX&T-Security-Security Infra & Delivery	596	29,131
581	8/26/24	DMND0210895	Enhancement	ServiceNow team - Mass Update Template form change	Approved	Infra Platforms & Services	ServiceNow	CX&T-IT-IP&S-IT Device Purch & Deploy	81	3,958
582	8/27/24	500596	Enhancement	Exchange Relay Deployment (Replace Proofpoint SER)	Approved	Security	Security	Security	150	48,750
583	8/27/24	500601	Enhancement	Automate carrier outage notifications and workflow	Screening	Security	Security	Security	60	7,500
584	9/3/24	DMND0211018	enhancement	Establish a ServiceNow portal dedicated to Corporate Safety & Health.	Submitted		ServiceNow	Safety Systems & Data	-	-
585	9/4/24	DMND0211053	Enhancement	ServiceNow AD Group & Member Integration	Qualified	App Platforms & Services	ServiceNow	Cx&T-IT-Digital Enablement	542	26,518
586	9/4/24	DMND0211073	enhancement	Connect Microsoft Project Online Data to Power BI	Submitted		Power BI	Cx&T-IT-Gen Ops & Electric Work Mgmnt	-	-
587	9/4/24	DMND0211098	Enhancement	LIAC for CARE MB customers	Approved	Customer	SAP CCS COLLECTIONS	CX&T-RO Credit & Collection	65	4,202
588	9/5/24	DMND0211125	Enhancement	DRMS Plan B DR Season Workaround Automation	Approved	Customer	IT CUST PROGRAMS - Demand Sid	CX&T-IT-CEO-Proj Mgmt	285	30,924
589	9/12/24	505392	Enhancement	CyberArk Lab Feature Parity to Production	Screening	Security	Security	Security	120	15,000
590	9/13/24	DMND0211305	Enhancement	Update Meterstand Leak Repair Pipe Info in FSS	Qualified	Gas	Service Suite	GE&S/GAM/SI-DIMP	30	6,886
591	9/13/24	506016	Enhancement	Deploy Azure workbook for mfa gaps	Screening	Security	Security	Security	20	2,500
592	9/15/24	506024	Enhancement	CyberArk intergration with Azure App Registration key	Screening	Security	Security	Security	250	31,250
593	9/15/24	506026	Enhancement	Venafi - PKI	Screening	Security	Security	Security	200	125,000
594	9/17/24	DMND0211368	Enhancement	Move Sub/Holton Circuit Holton from the Muskegon to Fremont	Qualified	Work Management	SAP WORK MANAGEMENT	Operations Software & Technology	-	96,111
595	9/18/24	508050	Enhancement	Azure Logging - Auxiliary logs + SOC Optimization	Screening	Security	Security	Security	40	5,000
596	9/18/24	DMND0211405	Enhancement	Need custom report developed to get Rehire comments.	Qualified	Corporate	SAP ERP HR	P&C-Application Development	-	18,778
597	9/19/24	508207	Enhancement	Integrate Azure Key Vault and OT Cyberark into Priv Account Seperation Process	Screening	Security	Security	Security	120	15,000
598	9/19/24	508431	Enhancement	Automation for ACE tool (ACE=Annual Compliance Evaluation)	Approved	Security	Security	Security	40	5,000
599	9/20/24	508626	Enhancement	Admin account unlock request	Screening	Security	Security	Security	80	10,000
600	9/20/24	DMND0211450	enhancement	Looking to automate apprentice information	Submitted		Microsoft Power Apps (MSPA)	Elec Opers Perf & Procedures	-	-
601	9/23/24	DMND0211495	Enhancement	Service Suite 3rd Party Damage - Condition on Arrival Required - KPMG	Qualified	Gas	Service Suite	Cx&T-IT-Work and Asset Management	-	5,047
602	9/23/24	509431	Enhancement	Quest Application Evaluation	Screening	Security	Security	Security	240	30,000
603	9/23/24	509432	Enhancement	MacOS Production VPN & iBoss	Approved	Security	Security	Security	40	5,000
604	9/23/24	509468	Enhancement	Governance of Azure	Screening	Security	Security	Security	240	30,000
605	9/23/24	509469	Enhancement	Governance of Group Policy Management	Screening	Security	Security	Security	150	18,750
606	9/23/24	509470	Enhancement	MFA Application Evaluation	Screening	Security	Security	Security	150	18,750
607	9/23/24	509471	Enhancement	SSO Application Evaluation	Screening	Security	Security	Security	160	20,000
608	9/23/24	509472	Enhancement	PKI SaaS Build	Screening	Security	Security	Security	160	20,000
609	9/23/24	509474	Enhancement	OT Domain Maturation	Screening	Security	Security	Security	160	20,000
610	9/23/24	509475	Enhancement	RSA Application Maturation	Screening	Security	Security	Security	160	20,000
611	9/23/24	509476	Enhancement	OT PAM Maturation	Screening	Security	Security	Security	160	20,000
612	9/23/24	509477	Enhancement	Identity Platform Documentation	Screening	Security	Security	Security	160	20,000
613	9/23/24	509478	Enhancement	CE QA Domain	Screening	Security	Security	Security	160	20,000
614	9/23/24	509479	Enhancement	Workflow to Transition Interns, Contractors to FTE	Screening	Security	Security	Security	160	20,000
615	9/23/24	509480	Enhancement	SAP - Rearchitect Roles	Screening	Security	Security	Security	160	20,000
616	9/23/24	509481	Enhancement	Break Glass Capabilities for Identity Platforms	Screening	Security	Security	Security	160	20,000
617	9/23/24	509488	Enhancement	Identity Platform Application Currency	Screening	Security	Security	Security	160	20,000
618	9/24/24	509707	Enhancement	OTAM SolarWinds Service Graph Connector	Screening	Security	Security	Security	160	20,000
619	9/25/24	510336	Enhancement	iBoss Filtering for Macs	Screening	Security	Security	Security	160	20,000
620	9/25/24	DMND0211590	Enhancement	ServiceNow create a notification email for device return tickets	Qualified	Infra Platforms & Services	ServiceNow	CX&T-IT-IP&S-IT Device Purch & Deploy	29	1,408
621	9/27/24	DMND0211628	Enhancement	Highlight NSCE tickets	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Risk & Controls	136	6,649
622	9/27/24	DMND0211631	Enhancement	We are looking to add a new piece to our Personas page for Gas Dispatch and Sche	Qualified	Gas	SAP PERSONAS DISTR SCHEDULIN	GO-Gas Dispatch & Scheduling Support	85	12,554
623	10/1/24	DMND0211666	Enhancement	Line Sensors Serial Number with field data collection	Screening	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
624	10/2/24	512355	Enhancement	Island Protocol Critical Service Isolation	Screening	Security	Security	Security	160	20,000
625	10/2/24	DMND0211683	Enhancement	Fleet - Default printer update for Jackson	Qualified	Customer	Fleet Diagnostics Applications	Field Operations Support A	39	2,297
626	10/2/24	DMND0211708	Enhancement	Changes to paper & eBill	Approved	Customer	SAP CCS BACK OFFICE	Rev Ops - Energy Assistance & Payment Pr	876	30,838
627	10/4/24	DMND0211756	enhancement	Please replace letter file with new postcard file in SAP for meter access	Submitted		SAP DESIGN DOCUMENTS	Brand & Creative Services	-	-
628	10/7/24	513759	Enhancement	Automatic Validation and Closure of Azure ARC and Sentinel ServiceNow Tickets	Screening	Security	Security	Security	160	20,000
629	10/8/24	514354	Enhancement	Implement DevOps Framework for Azure Logic Apps	Screening	Security	Security	Security	160	20,000
630	10/9/24	DMND0211846	enhancement	Create new integration from SAP to Baker Tilly (LCP Tracker)	Submitted		SAP ERP HR	CX&T-IT-CPF-P&C	-	-
631	10/9/24	514813	Enhancement	On-Call Calendar Integration	Submitted	Security	Security	Security	160	20,000
632	10/10/24	515053	Enhancement	Microsoft Premium Defender Threat Intelligence	Screening	Security	Security	Security	160	20,000
633	10/11/24	DMND0211901	Enhancement	RPA: Update Micro GADS Calculated Data	Qualified	App Platforms & Services	Microsoft Power Automate Deskt	CX&T-IT-Development Foundation	175	7,207
634	10/12/24	DMND0211905	Enhancement	Create Application Security Catalog Items	Qualified	Security	ServiceNow	CX&T-Security-Security Infra & Delivery	123	4,005
635	10/13/24	515765	Enhancement	Move Azure / o365 authentication from ADFS to Entra AD	Screening	Security	Security	Security	160	20,000
636	10/14/24	515778	Enhancement	Silverfort Implementation	Approved	Security	Security	Security	300	547,500
637	10/16/24	517942	Enhancement	ITAM - update the form for NFR process	Submitted	Security	Security	Security	160	20,000
638	10/17/24	518254	Enhancement	SquaredUp Replacement	Submitted	Security	Security	Security	160	20,000

Enhancement Worklist Detail
Information Technology
For Years 2016 Through October 21, 2024
($0)

Line No.	(a) Open Date	(b) Number	(c) Type	(d) Description	(e) State	(f) Portfolio	(g) Configuration Item	(h) Requestor Department	(i) Total Estimated Hours	(j) Planned Cost
639	10/17/24	DMND0212069	Enhancement	ZLTR Improvements	Qualified	Customer	IT CUST PROGRAMS - Transportat	CX&T-IT-CEO-Proj Mgmt	661	42,859

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected 13 Month Average of IT S/4 HANA Cloud Implementation Costs
For the years 2026 - 13 months balance ending April 30, 2027
Electric Allocation

Case No.: U-21870
Revised Exhibit No.: A-26 (SHB-11)
Page: 1 of 1
Witness: SHBaker
Date: June 2025

Line No.	(a) Description	(b) Bal. Ending 4/30/2026	(c) Bal. Ending 5/31/2026	(d) Bal. Ending 6/30/2026	(e) Bal. Ending 7/31/2026	(f) Bal. Ending 8/31/2026	(g) Bal. Ending 9/30/2026	(h) Bal. Ending 10/31/2026	(i) Bal. Ending 11/30/2026	(j) Bal. Ending 12/31/2026	(k) Bal. Ending 1/31/2027	(l) Bal. Ending 2/28/2027	(m) Bal. Ending 3/31/2027	(n) Bal. Ending 4/30/2027	(o) 13 mos. Average
1	**S/4HANA Cloud Implementation Costs**	$ 1,507,818	$ 1,698,197	$ 1,888,575	$ 2,078,953	$ 2,269,331	$ 2,459,710	$ 2,650,088	$ 2,840,466	$ 3,030,845	$ 3,124,264	$ 3,217,684	$ 3,311,104	$ 3,404,524	**$ 2,575,505**
2	**Total**	**$ 1,507,818**	**$ 1,698,197**	**$ 1,888,575**	**$ 2,078,953**	**$ 2,269,331**	**$ 2,459,710**	**$ 2,650,088**	**$ 2,840,466**	**$ 3,030,845**	**$ 3,124,264**	**$ 3,217,684**	**$ 3,311,104**	**$ 3,404,524**	**$ 2,575,505**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Current and Historical Credit Ratings
for the Projected Year Ending April 30, 2027

Case No.: U-21870
Exhibit No.: A-27 (MRB-8)
Page: 1 of 1
Witness: MRBleckman
Date: June 2025

Line No.		Credit Ratings (a)	(b)	(c)	(d)	(e)	(f)
1			Standard & Poors Ratings at Year End				
2		**Current**	**2024**	**2023**	**2022**	**2021**	**2020**
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-	N/A
17	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
18							
19							
20			Moody's Ratings at Year End				
21		**Current**	**2024**	**2023**	**2022**	**2021**	**2020**
22	**Consumers Energy Company**						
23	Senior Secured Debt	A1	A1	A1	A1	A1	Aa3
24	Commercial Paper	P-2	P-2	P-2	P-2	P-2	P-1
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	Baa1	Baa1	Baa1	Baa1	Baa1	A3
28	Outlook	Stable	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	Baa1
33	Junior Subordinated Debt	Baa3	Baa3	Baa3	Baa3	Baa3	Baa2
34	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
35	Preferred Stock	Ba1	Ba1	Ba1	Ba1	Ba1	N/A
36	Outlook	Stable	Stable	Stable	Stable	Stable	Negative
37							
38							
39			Fitch Ratings at Year End				
40		**Current**	**2024**	**2023**	**2022**	**2021**	**2020**
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+	N/A
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, 2027

Case No.: U-21870
Exhibit No.: A-28 (MRB-9)
Page: 1 of 5
Witness: MRBleckman
Date: June 2025

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	01/03/23	ES	Connecticut Light & Power Company	Secured	500	5.250%	A1	A+	01/15/53	+135
2	01/03/23	OGE	Oklahoma Gas & Electric	Unsecured	450	5.400%	A3	A-	01/15/33	+165
3	01/03/23	EXC	Commonwealth Edison	Secured	400	4.900%	A1	A	02/01/33	+115
4	01/03/23	EXC	Commonwealth Edison	Secured	575	5.300%	A1	A	02/01/53	+140
5	01/03/23	DUK	Duke Energy Carolinas	Secured	900	4.950%	Aa3	A	1/15/2033	+120
6	01/03/23	DUK	Duke Energy Carolinas	Secured	900	5.350%	Aa3	A	1/15/2053	+145
7	01/03/23	AEP	Public Service Co. of Oklahoma	Unsecured	475	5.250%	Baa1	A-	1/15/2033	+150
8	01/03/23	ETR	Entergy Arkansas	Secured	425	5.150%	A2	A	1/15/2033	+140
9	**01/03/23**	**CMS**	**Consumers Energy**	**Secured**	**425**	**4.650%**	**A1**	**A**	**3/1/2028**	**+75**
10	01/04/23	PCG	Pacific Gas and Electric	Secured	750	6.150%	Baa3	BBB-	1/15/2033	+250
11	01/04/23	PCG	Pacific Gas and Electric	Secured	750	6.750%	Baa3	BBB-	1/15/2053	+295
12	01/04/23	ES	Public Service New Hampshire	Secured	300	5.150%	A1	A+	1/15/2053	+133
13	01/10/23	WEC	WEC Energy Group	Unsecured	650	4.750%	Baa1	BBB+	1/9/2026	+85
14	01/10/23	WEC	WEC Energy Group	Unsecured	450	4.750%	Baa1	BBB+	1/15/2028	+113
15	02/02/23	NRUC	National Rural Utilities	Unsecured	600	4.450%	A2	A-	03/13/26	+70
16	02/02/23	NRUC	National Rural Utilities (Reopening)	Unsecured	200	4.800%	A2	A-	03/15/28	+95
17	02/02/23	NRUC	National Rural Utilities (Reopening)	Secured	300	5.800%	A1	A-	01/15/33	+123
18	02/06/23	NEE	NextEra Energy Capital Holdings	Unsecured	1,250	4.900%	Baa1	BBB+	02/28/28	+110
19	02/06/23	NEE	NextEra Energy Capital Holdings	Unsecured	600	5.000%	Baa1	BBB+	02/28/30	+125
20	02/06/23	NEE	NextEra Energy Capital Holdings	Unsecured	1,000	5.050%	Baa1	BBB+	02/28/33	+140
21	02/06/23	NEE	NextEra Energy Capital Holdings	Unsecured	1,150	5.250%	Baa1	BBB+	02/28/53	+155
22	02/06/23	SR	Spire Missouri Inc	Secured	400	4.800%	A1	A	02/15/33	+120
23	**02/13/23**	**CMS**	**Consumers Energy**	**Secured**	**700**	**4.625%**	**A1**	**A**	**05/15/33**	**+97**
24	02/13/23	FTSCN	Tucson Electric Power Co	Unsecured	375	5.500%	A3	A-	04/15/53	+175
25	02/16/23	EXC	Exelon Corp	Unsecured	1,000	5.150%	Baa2	BBB	03/15/28	+113
26	02/16/23	EXC	Exelon Corp	Unsecured	850	5.300%	Baa2	BBB	03/15/33	+145
27	02/16/23	EXC	Exelon Corp	Unsecured	650	5.600%	Baa2	BBB	03/15/53	+170
28	02/21/23	CEG	Constellation Energy Generation LLC	Unsecured	750	5.600%	Baa2	BBB	03/01/28	+143
29	02/21/23	CEG	Constellation Energy Generation LLC	Unsecured	600	5.800%	Baa2	BBB	03/01/33	+185
30	02/21/23	CNP	CenterPoint Energy Resources Corp	Unsecured	600	5.250%	A3	BBB+	03/01/28	+115
31	02/21/23	CNP	CenterPoint Energy Resources Corp	Unsecured	600	5.400%	A3	BBB+	03/01/33	+145
32	02/21/23	ED	Consolidated Edison Co of New York Inc	Unsecured	500	5.200%	Baa1	A-	03/01/33	+125
33	02/22/23	NEE	NextEra Energy Capital Holdings Inc	Unsecured	2,500	6.051%	Baa1	BBB+	03/01/25	+120
34	02/27/23	AEE	Union Electric Co	Secured	500	5.450%	A2	A	03/15/53	+155
35	02/27/23	AEP	American Electric Power Co Inc	Unsecured	850	5.625%	Baa2	BBB	03/01/33	+175
36	02/27/23	DTE	DTE Electric Co	Secured	600	5.200%	Aa3	A	04/01/33	+130
37	02/27/23	DTE	DTE Electric Co	Secured	600	5.400%	Aa3	A	04/01/53	+148
38	02/27/23	EIX	Southern California Edison Co	Secured	750	5.300%	A2	A-	03/01/28	+115
39	02/27/23	EIX	Southern California Edison Co	Secured	450	5.700%	A2	A-	03/01/53	+180
40	02/27/23	PPL	PPL Electric Utilities Corp	Secured	600	5.000%	A1	A+	05/15/33	+120
41	02/27/23	PPL	PPL Electric Utilities Corp	Secured	750	5.250%	A1	A+	05/15/53	+145
42	02/28/23	NEE	Florida Power & Light Co	Secured	1,000	5.050%	Aa2	A+	04/01/28	+90
43	02/28/23	NEE	Florida Power & Light Co	Secured	750	5.100%	Aa2	A+	04/01/33	+120
44	02/28/23	NEE	Florida Power & Light Co	Secured	750	5.300%	Aa2	A+	04/01/53	+140
45	03/01/23	EIX	Edison International	Unsecured	500	8.125%	Baa3	BB+	06/15/53	+386
46	03/01/23	ES	Eversource Energy	Unsecured	750	5.450%	Baa1	BBB+	03/01/28	+123
47	03/01/23	NGGLN	KeySpan Gas East Corp	Unsecured	500	5.994%	Baa1	BBB+	03/06/33	+200
48	03/02/23	BKH	Black Hills Corp	Unsecured	350	5.950%	Baa2	BBB+	03/15/28	+170
49	03/02/23	NRG	NRG Energy Inc	Secured	740	7.000%	Baa3	BBB-	03/15/33	+310
50	03/02/23	NRG	NRG Energy Inc	Unsecured	650	10.250%	Ba3	B	PerpNC5	+592
51	03/02/23	NWN	Northwest Natural Gas Co	Secured	100	5.750%	A2	AA-	03/15/33	+170
52	03/06/23	DUK	Duke Energy Progress LLC	Secured	500	5.250%	Aa3	A	03/15/33	+128
53	03/06/23	DUK	Duke Energy Progress LLC	Secured	500	5.350%	Aa3	A	03/15/53	+148
54	03/06/23	SRE	San Diego Gas & Electric Co	Secured	800	5.350%	A1	A	04/01/53	+150
55	03/07/23	EVRG	Evergy Kansas Central Inc	Secured	400	5.700%	A2	A	03/15/53	+185
56	03/08/23	ETR	System Energy Resources Inc	Secured	325	6.000%	Baa1	A	04/15/28	+255
57	03/09/23	AEP	AEP Transmission Co LLC	Secured	700	5.400%	A2	A-	03/15/53	+157
58	03/09/23	IDA	Idaho Power Co	Secured	400	5.500%	A2	A-	03/15/53	+170
59	03/09/23	PPL	Kentucky Utilities Co	Secured	400	5.450%	A1	A	04/15/33	+155
60	03/09/23	PPL	Louisville Gas and Electric Co	Secured	400	5.450%	A1	A	04/15/33	+155
61	03/20/23	CNP	CenterPoint Energy Houston Electric LLC	Secured	600	4.950%	A2	A	04/01/33	+150
62	03/20/23	CNP	CenterPoint Energy Houston Electric LLC	Secured	300	5.300%	A2	A	04/01/53	+165
63	03/20/23	DUK	Duke Energy Ohio Inc	Secured	375	5.250%	A2	A	04/01/33	+175
64	03/20/23	DUK	Duke Energy Ohio Inc	Secured	375	5.650%	A2	A	04/01/53	+200
65	03/21/23	AEP	Indiana Michigan Power Co	Unsecured	500	5.625%	A3	A-	04/01/53	+190
66	03/21/23	DUK	Duke Energy Indiana LLC	Secured	500	5.400%	Aa3	A	04/01/53	+170
67	03/21/23	NI	NiSource Inc	Unsecured	750	5.250%	Baa2	BBB+	03/30/28	+155
68	03/21/23	OGE	Oklahoma Gas and Electric Co	Unsecured	350	5.600%	A3	A-	04/01/53	+190
69	03/21/23	SWX	Southwest Gas Corp	Unsecured	300	5.450%	Baa1	BBB	03/23/28	+175
70	03/23/23	PEG	Public Service Electric and Gas Co	Secured	500	4.650%	A1	A	03/15/33	+122
71	03/23/23	PEG	Public Service Electric and Gas Co	Secured	400	5.125%	A1	A	03/15/53	+142
72	03/27/23	LNT	Wisconsin Power & Light	Unsecured	300	4.950%	A3	A	04/01/33	+145
73	03/27/23	TVA	Tennessee Valley Authority	Unsecured	1,000	3.875%	Aaa	AA+	03/15/28	+45
74	03/27/23	XEL	Public Service Co of Colorado	Secured	850	5.250%	A1	A	04/01/53	+155
75	03/28/23	AEP	Southwestern Electric Power Co	Unsecured	350	5.300%	Baa2	A-	04/01/33	+178
76	03/28/23	D	Virginia Electric Power Co	Unsecured	750	5.000%	A2	BBB+	04/01/33	+150
77	03/28/23	D	Virginia Electric Power Co	Unsecured	750	5.450%	A2	BBB+	04/01/53	+175
78	03/28/23	FE	Metropolitan Edison Co	Unsecured	425	5.200%	A3	BBB	04/01/28	+160
79	03/28/23	FE	Pennsylvania Electric Co	Unsecured	300	5.150%	Baa1	BBB	03/30/26	+140
80	03/28/23	PCG	Pacific Gas and Electric Co	Secured	750	6.700%	Baa3	BBB-	04/01/53	+295
81	04/03/23	EVRG	Evergy Metro Inc	Secured	300	4.950%	A2	A+	04/15/33	+153
82	04/04/23	WEC	WEC Energy Group Inc (reopening)	Unsecured	350	4.750%	Baa1	BBB+	01/09/26	+100
83	04/19/23	EIX	SCE Recovery Funding LLC	Secured	425	4.697%	Aaa	AAA	06/15/40	+110
84	04/19/23	EIX	SCE Recovery Funding LLC	Secured	350	5.112%	Aaa	AAA	12/15/47	+120
85	05/01/23	CNP	CenterPoint Energy Resources Corp (Reopening)	Unsecured	300	5.250%	A3	BBB+	03/01/28	+100
86	05/01/23	SO	Georgia Power Co	Unsecured	750	4.650%	Baa1	BBB+	05/16/28	+105
87	05/01/23	SO	Georgia Power Co	Unsecured	1,000	4.950%	Baa1	BBB+	05/17/33	+140
88	05/01/23	XEL	Northern States Power Company	Secured	800	5.100%	Aa3	A	05/15/53	+135
89	05/08/23	AEP	Ohio Power Co	Unsecured	400	5.000%	Baa1	A-	06/01/33	+155
90	05/08/23	DTE	DTE Energy Co	Unsecured	800	4.875%	Baa2	BBB	06/01/28	+140
91	05/08/23	ES	Eversource Energy	Unsecured	450	4.750%	Baa1	BBB+	05/15/26	+105
92	05/08/23	ES	Eversource Energy	Unsecured	550	5.450%	Baa1	BBB+	03/01/28	+130
93	05/08/23	ES	Eversource Energy	Unsecured	800	5.125%	Baa1	BBB+	05/15/33	+163
94	05/08/23	EXC	Baltimore Gas and Electric Co	Unsecured	700	5.400%	A3	A	06/01/53	+158
95	05/08/23	ONCRTX	Oncor Electric Delivery Co	Secured	600	4.300%	A2	A+	05/15/28	+85
96	05/08/23	ONCRTX	Oncor Electric Delivery Co (reopening)	Secured	400	4.950%	A2	A+	09/15/52	+145
97	05/09/23	ETR	Entergy Mississippi LLC	Secured	300	5.000%	A2	A	09/01/33	+148
98	05/10/23	EIX	Edison International	Unsecured	600	5.250%	Baa2	BBB-	11/15/28	+190
99	05/15/23	AES	The AES Corp	Unsecured	900	5.450%	Baa3	BBB-	06/01/28	+200
100	05/15/23	BRKHEC	PacifiCorp	Secured	1,200	5.500%	A1	A+	05/15/54	+165
101										

102 FRN: Floating Rate Note

103 MS: Mid-Swap - The average of the bid and offer swap rates for a reference maturity

104 Source: Barclays Bank

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending April 30, 2027

Case No.: U-21870
Exhibit No.: A-28 (MRB-9)
Page: 2 of 5
Witness: MRBleckman
Date: June 2025

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	05/15/23	NEE	Florida Power & Light Co	Unsecured	500	4.450%	A1	A	05/15/26	+80
2	05/15/23	NEE	Florida Power & Light Co	Secured	750	4.400%	Aa2	A+	05/15/28	+95
3	05/15/23	NEE	Florida Power & Light Co	Secured	500	4.625%	Aa2	A+	05/15/30	+115
4	05/15/23	NEE	Florida Power & Light Co	Secured	750	4.800%	Aa2	A+	05/15/33	+130
5	05/15/23	PSD	Puget Sound Energy Inc	Secured	400	5.448%	A2	A-	06/01/53	+160
6	05/15/23	SO	The Southern Co	Unsecured	750	4.850%	Baa2	BBB	06/15/28	+143
7	05/15/23	SO	The Southern Co	Unsecured	750	5.200%	Baa2	BBB	06/15/33	+173
8	05/17/23	EDF FP	Electricite de France SA	Unsecured	1,000	5.700%	Baa1	BBB	05/23/28	+215
9	05/17/23	EDF FP	Electricite de France SA	Unsecured	1,000	6.250%	Baa1	BBB	05/23/33	+270
10	05/17/23	EDF FP	Electricite de France SA	Unsecured	1,000	6.900%	Baa1	BBB	05/23/53	+310
11	05/17/23	EIX	Southern California Edison Co	Secured	400	4.900%	A2	A-	06/01/26	+113
12	05/17/23	EIX	Southern California Edison Co	Secured	700	5.875%	A2	A-	12/01/53	+200
13	05/17/23	ITC	ITC Holdings Corp	Unsecured	500	5.400%	Baa2	BBB+	06/01/33	+185
14	05/17/23	ITC	ITC Holdings Corp (reopening)	Unsecured	300	4.950%	Baa2	BBB+	09/22/27	+135
15	05/17/23	NRUC	National Rural Utilities Cooperative Finance Corp	Pref/Hybrid	300	7.125%	A3	BBB	09/15/53	+353
16	05/17/23	SRE	Southern California Gas Co	Secured	500	5.200%	Aa3	A+	06/01/33	+165
17	05/17/23	SRE	Southern California Gas Co	Secured	500	5.750%	Aa3	A+	06/01/53	+190
18	05/22/23	AEP	AEP Texas Inc	Unsecured	450	5.400%	Baa2	A-	06/01/33	+172
19	05/23/23	AEE	Ameren Illinois Company	Secured	500	4.950%	A1	A	06/01/33	+127
20	05/30/23	NI	NiSource Inc.	Unsecured	450	5.400%	Baa2	BBB+	06/30/33	+175
21	05/30/23	NI	NiSource Inc.(Reopening)	Unsecured	300	5.250%	Baa2	BBB+	03/30/28	+135
22	05/31/23	AEP	American Electric Power Co Inc	Jr. Sub Notes	850	5.699%	Baa3	BBB+	08/15/25	+155
23	06/01/23	PCG	Pacific Gas and Electric Co	Secured	850	6.100%	Baa3	BBB-	01/15/29	+240
24	06/01/23	PCG	Pacific Gas and Electric Co	Secured	1,150	6.400%	Baa3	BBB-	06/15/33	+280
25	06/01/23	PCG	Pacific Gas and Electric Co (Reopening)	Secured	500	6.750%	Baa3	BBB-	01/15/53	+315
26	06/05/23	DUK	Piedmont Natural Gas Co	Unsecured	350	5.400%	A3	BBB+	06/15/33	+170
27	06/08/23	VST	Palomino Funding Trust I	Secured	450	7.233%	Baa3	BBB-	05/17/28	+338
28	06/13/23	DUK	Duke Energy Carolinas LLC	Secured	500	5.400%	Aa3	A	01/15/54	+150
29	06/13/23	DUK	Duke Energy Carolinas LLC (Reopening)	Secured	350	4.950%	Aa3	A	01/15/33	+130
30	06/15/23	EXC	PECO Energy Co	Secured	575	4.900%	Aa3	A	06/15/33	+120
31	06/20/23	SRE	Sempra Energy	Unsecured	550	5.400%	Baa2	BBB	08/01/26	+123
32	06/20/23	SRE	Sempra Energy	Unsecured	700	5.500%	Baa2	BBB	08/01/33	+180
33	06/21/23	CNP	SIGECO Securitization I	Secured	215	5.026%	Aaa	AAA	11/15/38	+118
34	06/21/23	CNP	SIGECO Securitization I	Secured	126	5.172%	Aaa	AAA	05/15/43	+145
35	06/26/23	ES	The Connecticut Light & Power Co	Secured	300	4.900%	A1	A+	07/01/33	+120
36	06/26/23	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	400	5.050%	A2	A-	09/15/28	+110
37	06/27/23	PNW	Arizona Public Service Co	Unsecured	500	5.550%	A3	BBB+	08/01/33	+180
38	07/17/23	NGGLN	Boston Gas Company	Unsecured	400	6.119%	Baa1	BBB+	07/20/53	+218
39	**07/31/23**	**CMS**	**Consumers Energy Company**	**Unsecured**	**500**	**4.900%**	**A1**	**A**	**02/15/29**	**+75**
40	07/31/23	XEL	Xcel Energy	Unsecured	800	5.450%	Baa1	BBB+	08/15/33	+153
41	08/03/23	AGR	New York State Electric & Gas	Unsecured	350	5.650%	Baa1	A-	08/15/28	+140
42	08/03/23	AGR	New York State Electric & Gas	Unsecured	400	5.850%	Baa1	A-	08/15/33	+168
43	08/03/23	PEG	Public Service Electric and Gas Co	Secured	500	5.200%	A1	A	08/01/33	+103
44	08/03/23	PEG	Public Service Electric and Gas Co	Secured	400	5.450%	A1	A	08/01/53	+115
45	08/07/23	NEE	NextEra Energy Capital Holdings	Unsecured	2,000	5.749%	Baa1	BBB+	09/01/25	+100
46	08/07/23	SRE	SDG&E	Secured	600	4.950%	A1	A	08/15/28	+90
47	08/08/23	CNP	CenterPoint Energy Inc	Unsecured	400	5.250%	Baa2	BBB	08/10/26	+90
48	08/08/23	D	Virginia Electric Power Co	Unsecured	400	5.300%	A2	BBB+	08/15/33	+128
49	08/08/23	D	Virginia Electric Power Co	Unsecured	600	5.700%	A2	BBB+	08/15/53	+150
50	08/08/23	ETR	Entergy Texas	Secured	350	5.800%	A3	A	09/01/53	+160
51	08/14/23	ETR	Entergy Arkansas	Secured	300	5.300%	A2	A	09/15/33	+120
52	08/15/23	NRG	Alexander Funding Trust	Secured	500	7.467%	Baa3	BBB-	07/31/28	+310
53	09/05/23	SO	The Southern Co	Unsecured	600	5.500%	Baa2	BBB	03/15/29	+113
54	09/05/23	SO	The Southern Co	Unsecured	700	5.700%	Baa2	BBB	03/15/34	+148
55	09/05/23	DUK	Duke Energy Corp	Unsecured	600	5.750%	Baa2	BBB	09/15/33	+150
56	09/05/23	DUK	Duke Energy Corp	Unsecured	750	6.100%	Baa2	BBB	09/15/53	+173
57	09/05/23	BRKHEC	MidAmerican Energy Co	Secured	350	5.350%	Aa2	A+	01/15/34	+110
58	09/05/23	BRKHEC	MidAmerican Energy Co	Secured	1,000	5.850%	Aa2	A+	09/15/54	+147
59	09/05/23	WEC	WEC Energy Group Inc	Unsecured	600	5.600%	Baa1	BBB+	09/12/26	+93
60	09/06/23	BKH	Black Hills Corporation	Unsecured	450	6.150%	Baa2	BBB+	05/14/34	+195
61	09/06/23	IDA	Idaho Power Co	Secured	350	5.800%	A2	A-	04/01/54	+150
62	09/11/23	SO	Southern Company Gas Capital Corp	Unsecured	500	5.750%	Baa1	BBB+	09/15/33	+148
63	09/11/23	BRKHEC	Nevada Power Co	Secured	500	6.000%	A2	A+	03/15/54	+163
64	09/12/23	VST	Vistra Operations Co LLC	Secured	650	6.950%	Baa3	BBB-	10/15/33	+270
65	09/12/23	FE	Monongahela Power Co	Secured	400	5.850%	A3	A-	02/15/34	+160
66	09/12/23	NGGLN	Brooklyn Union Gas Company	Unsecured	400	6.388%	Baa2	BBB+	09/15/33	+212
67	09/13/23	CNP	CenterPoint Energy Houston Electric LLC	Secured	500	5.200%	A2	A	10/01/28	+85
68	09/13/23	BRKHEC	Sierra Pacific Power Co	Secured	400	5.900%	A2	A+	03/15/54	+160
69	09/18/23	LNT	Interstate Power and Light Co	Unsecured	300	5.700%	Baa1	A-	10/15/33	+145
70	09/18/23	ES	Public Service Co of New Hampshire	Secured	300	5.350%	A1	A+	10/01/33	+105
71	09/18/23	ES	NSTAR Electric Co	Unsecured	150	5.600%	A1	A	10/01/28	+115
72	09/26/23	CEG	Constellation Energy Generation LLC	Unsecured	500	6.125%	Baa2	BBB	01/15/34	+158
73	09/26/23	CEG	Constellation Energy Generation LLC	Unsecured	900	6.500%	Baa2	BBB	10/01/53	+180
74	09/26/23	EIX	Southern California Edison Co	Secured	550	5.650%	A2	A-	10/01/28	+105
75	10/02/23	PEG	Public Service Enterprise Group	Unsecured	600	5.875%	Baa2	BBB	10/15/28	+120
76	10/02/23	PEG	Public Service Enterprise Group	Unsecured	400	6.125%	Baa2	BBB	10/15/33	+150
77	10/04/23	D	Dominion Energy South Carolina Inc	Secured	500	6.250%	A2	A	10/15/53	+140
78	10/05/23	ATO	Atmos Energy	Unsecured	400	5.900%	A1	A-	11/15/33	+120
79	10/05/23	ATO	Atmos Energy	Unsecured	500	6.200%	A1	A-	11/15/53	+133
80	10/30/23	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	400	5.600%	A2	A-	11/13/26	+73
81	11/06/23	DUK	Duke Energy Florida LLC	Secured	600	5.875%	A1	A	11/15/33	+125
82	11/06/23	DUK	Duke Energy Florida LLC	Secured	700	6.200%	A1	A	11/15/53	+142
83	11/06/23	PCG	Pacific Gas and Electric Co	Secured	800	6.950%	Baa3	BBB-	03/15/34	+233
84	11/06/23	SO	Alabama Power Co	Unsecured	300	5.850%	A1	A-	11/15/33	+120
85	11/07/23	LNT	Alliant Energy Finance LLC	Unsecured	300	5.950%	Baa2	BBB+	03/30/29	+147
86	11/08/23	AEP	Kentucky Power Co	Unsecured	375	7.000%	Baa3	BBB	11/15/33	+250
87	11/08/23	ES	Eversource Energy	Unsecured	800	5.950%	Baa2	BBB+	02/01/29	+147
88	11/08/23	EVRG	Evergy Kansas Central Inc	Secured	300	5.900%	A2	A	11/15/33	+140
89	11/08/23	ONCRTX	Oncor Electric Delivery Co LLC	Secured	800	5.650%	A2	A+	11/15/33	+115
90	11/15/23	AEE	Ameren Corporation	Unsecured	600	5.700%	Baa1	BBB	12/01/26	+105
91	11/20/23	ED	Consolidated Edison Co of New York Inc	Unsecured	600	5.500%	A3	A-	03/15/34	+115
92	11/20/23	ED	Consolidated Edison Co of New York Inc	Unsecured	900	5.900%	A3	A-	11/15/53	+138
93	11/28/23	OGLETH	Oglethorpe Power Corp	Secured	400	6.200%	Baa1	BBB+	12/01/53	+175
94	12/04/23	EIX	Edison International	Pref/Hybrid	450	7.875%	Baa3	BB+	06/15/54	+366
95	12/06/23	AEP	American Electric Power Company	Unsecured	1,000	5.200%	Baa2	BBB+	01/15/29	+113
96	12/11/23	OGS	ONE Gas Inc	Unsecured	300	5.100%	A3	A-	4/1/2029	+87
97	12/11/23	VST	Vistra Operations Co LLC (Reopening)	Secured	400	6.950%	Baa3	BBB-	10/15/33	+240
98	12/18/23	AEE	Ameren Corporation	Unsecured	700	5.000%	Baa2	BBB	01/15/29	+110
99	01/02/24	DUK	Duke Energy Corp	Unsecured	550	4.850%	Baa2	BBB	1/5/2027	+75
100	01/02/24	DUK	Duke Energy Corp	Unsecured	550	4.850%	Baa2	BBB	1/5/2029	+95

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending April 30, 2027

Case No.: U-21870
Exhibit No.: A-28 (MRB-9)
Page: 3 of 5
Witness: MRBleckman
Date: June 2025

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	D	Virginia Electric and Power Co	Unsecured	500	5.000%	A2	BBB+	01/15/34	+115
2	01/02/24	D	Virginia Electric and Power Co	Unsecured	500	5.350%	A2	BBB+	01/15/54	+127
3	01/02/24	PPL	PPL Electric Utilities Corp	Secured	650	4.850%	A1	A+	02/15/34	+92
4	**01/02/24**	**CMS**	**Consumers Energy Co**	**Secured**	**600**	**4.600%**	**A1**	**A**	**05/30/29**	**+73**
5	01/03/24	BRKHEC	PacifiCorp	Secured	500	5.100%	A2	A	02/15/29	+120
6	01/03/24	BRKHEC	PacifiCorp	Secured	700	5.300%	A2	A	02/15/31	+140
7	01/03/24	BRKHEC	PacifiCorp	Secured	1,100	5.450%	A2	A	02/15/34	+155
8	01/03/24	BRKHEC	PacifiCorp	Secured	1,500	5.800%	A2	A	01/15/55	+175
9	01/03/24	DUK	Duke Energy Carolinas LLC	Secured	575	4.850%	Aa3	A	01/15/34	+100
10	01/03/24	DUK	Duke Energy Carolinas LLC (Reopening)	Secured	425	5.400%	Aa3	A	01/15/54	+118
11	01/03/24	AEE	Union Electric Co	Secured	350	5.250%	A2	A	01/15/54	+123
12	01/04/24	WTRG	Essential Utilities Inc	Unsecured	500	5.375%	Baa2	A-	01/15/34	+140
13	01/08/24	EIX	Southern California Edison Co	Secured	500	4.875%	A2	A-	02/01/27	+75
14	01/08/24	EIX	Southern California Edison Co	Secured	900	5.200%	A2	A-	06/01/34	+120
15	01/08/24	NGGLN	National Grid PLC	Unsecured	750	5.418%	Baa2	BBB	01/11/34	+142
16	01/09/24	AQNCN	Liberty Utilities Co	Unsecured	500	5.577%	Baa2	BBB	01/31/29	+160
17	01/09/24	AQNCN	Liberty Utilities Co	Unsecured	350	5.869%	Baa2	BBB	01/31/34	+185
18	01/11/24	NGGLN	Niagara Mohawk Power	Unsecured	500	5.290%	Baa1	BBB+	01/17/34	+130
19	01/11/24	NGGLN	Niagara Mohawk Power	Unsecured	700	5.664%	Baa1	BBB+	01/17/54	+145
20	01/16/24	ES	Eversource Energy	Unsecured	350	5.000%	Baa2	BBB+	1/1/2027	+100
21	01/16/24	ES	Eversource Energy	Unsecured	650	5.500%	Baa2	BBB+	1/1/2034	+150
22	01/16/24	ES	Connecticut Light and Power Co	Secured	350	4.650%	A1	A+	1/1/2029	+75
23	01/22/24	BRKHEC	MidAmerican Energy	Secured	600	5.300%	Aa2	A	02/01/55	+98
24	01/25/24	TE	Tampa Electric	Unsecured	500	4.900%	A3	BBB+	03/01/29	+88
25	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	600	FRN	Baa1	BBB+	01/29/26	+76
26	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	1,000	4.950%	Baa1	BBB+	01/29/26	+65
27	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	900	4.900%	Baa1	BBB+	03/15/29	+95
28	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	1,100	5.250%	Baa1	BBB+	03/15/34	+120
29	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	800	5.550%	Baa1	BBB+	03/15/54	+125
30	01/29/24	BRKHEC	Northern Natural Gas Co	Unsecured	500	5.625%	A2	A-	02/01/54	+127
31	02/06/24	SR	Spire Inc	Unsecured	350	5.300%	Baa2	BBB+	03/01/26	+85
32	02/12/24	DTE	DTE Energy Co	Unsecured	1,200	5.100%	Baa2	BBB	03/01/29	+103
33	02/20/24	AWK	American Water Capital Corp	Unsecured	700	5.150%	Baa1	A	03/01/34	+92
34	02/20/24	AWK	American Water Capital Corp	Unsecured	700	5.450%	Baa1	A	03/01/54	+107
35	02/20/24	SO	Georgia Power Co	Unsecured	500	5.004%	Baa1	BBB+	02/23/27	+62
36	02/20/24	SO	Georgia Power Co	Unsecured	900	5.250%	Baa1	BBB+	03/15/34	+102
37	02/20/24	DTE	DTE Electric Co	Secured	500	4.850%	Aa3	A	12/01/26	+47
38	02/20/24	DTE	DTE Electric Co	Secured	500	5.200%	Aa3	A	03/01/34	+93
39	02/21/24	NGGLN	Massachusetts Electric Co	Unsecured	400	5.867%	Baa1	BBB+	02/26/54	+138
40	02/22/24	EXC	Exelon Corp	Unsecured	650	5.150%	Baa2	BBB	03/15/29	+88
41	02/22/24	EXC	Exelon Corp	Unsecured	650	5.450%	Baa2	BBB	03/15/34	+115
42	02/22/24	EXC	Exelon Corp (Reopening)	Unsecured	400	5.600%	Baa2	BBB	03/15/53	+130
43	02/22/24	XEL	Northern States Power Co/MN	Secured	700	5.400%	Aa3	A+	03/15/54	+97
44	02/26/24	PCG	Pacific Gas and Electric Co	Secured	850	5.550%	Baa2	BBB	05/15/29	+125
45	02/26/24	PCG	Pacific Gas and Electric Co	Secured	1,100	5.800%	Baa2	BBB	05/15/34	+153
46	02/26/24	PCG	Pacific Gas and Electric Co (Reopening)	Secured	300	6.750%	Baa2	BBB	01/15/53	+170
47	02/26/24	SO	The Southern Co (Reopening)	Unsecured	400	5.500%	Baa2	BBB	03/15/29	+85
48	02/26/24	SO	The Southern Co (Reopening)	Unsecured	400	5.700%	Baa2	BBB	03/15/34	+117
49	02/26/24	XEL	Xcel Energy Inc	Unsecured	800	5.500%	Baa1	BBB+	03/15/34	+125
50	02/26/24	EXC	Potomac Electric Power Co	Secured	375	5.200%	A2	A	03/15/34	+95
51	02/26/24	EXC	Potomac Electric Power Co	Secured	300	5.500%	A2	A	03/15/54	+110
52	02/26/24	CNP	CenterPoint Energy Houston Electric LLC	Secured	400	5.150%	A2	A	03/01/34	+90
53	02/26/24	DUK	Duke Energy Indiana LLC	Secured	300	5.250%	Aa3	A	03/01/34	+100
54	02/27/24	EIX	Southern California Edison Co	Secured	600	5.350%	A2	A-	03/01/26	+62
55	02/27/24	EIX	Southern California Edison Co	Secured	600	5.150%	A2	A-	06/01/29	+83
56	02/27/24	EIX	Southern California Edison Co	Secured	400	5.750%	A2	A-	04/15/54	+135
57	02/27/24	NEE	NextEra Energy Capital Holdings Inc	Pref/Hybrid	1,000	6.700%	Baa2	BBB	09/01/54	+242
58	02/28/24	PEG	Public Service Electric and Gas Co	Secured	450	5.200%	A1	A	03/01/34	+93
59	02/28/24	PEG	Public Service Electric and Gas Co	Secured	550	5.450%	A1	A	03/01/54	+108
60	03/04/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	1,000	4.850%	Baa1	BBB+	04/30/31	+142
61	03/04/24	ETR	Entergy Louisiana LLC	Secured	500	5.350%	A2	A	03/15/34	+115
62	03/04/24	ETR	Entergy Louisiana LLC	Secured	700	5.700%	A2	A	03/15/54	+135
63	03/04/24	LNT	Wisconsin Power and Light Co	Unsecured	300	5.375%	Baa1	A	03/30/34	+118
64	03/06/24	AES	AES Andes SA	Unsecured	500	6.300%	Baa3	BBB-	03/15/29	+220
65	03/07/24	AES	Indianapolis Power & Light Co	Secured	650	5.700%	A2	A-	04/01/54	+147
66	03/08/24	AES	IPALCO Enterprises Inc	Secured	400	5.750%	Baa3	BBB-	04/01/34	+170
67	03/11/24	NI	NiSource Inc	Unsecured	650	5.350%	Baa2	BBB+	04/01/34	+128
68	03/11/24	SRE	Sempra Energy	Pref/Hybrid	600	6.875%	Baa3	BBB-	10/01/54	+279
69	03/11/24	DUK	Duke Energy Progress LLC	Secured	500	5.100%	Aa3	A	03/15/34	+103
70	03/11/24	AEP	AEP Transmission Co LLC	Unsecured	450	5.150%	A2	BBB+	04/01/34	+105
71	03/11/24	DUK	Duke Energy Ohio Inc	Secured	425	5.550%	A2	A	03/15/54	+130
72	03/12/24	CEG	Constellation Energy Generation LLC	Unsecured	900	5.750%	Baa2	BBB+	03/15/54	+145
73	03/12/24	SRE	Southern California Gas Co	Secured	500	5.600%	Aa3	A+	04/01/54	+133
74	03/18/24	SRE	San Diego Gas & Electric Co	Secured	600	5.550%	A1	A	04/15/54	+115
75	03/18/24	AEP	Appalachian Power Co	Unsecured	400	5.650%	Baa1	BBB+	04/01/34	+135
76	03/19/24	ES	Public Service Co of New Hampshire (Reopening)	Secured	300	5.350%	A1	A+	10/01/33	+95
77	03/21/24	PPL	The Narragansett Electric Co	Unsecured	500	5.350%	A3	A-	05/01/34	+108
78	03/25/24	PEG	Public Service Enterprise Group Inc	Unsecured	750	5.200%	Baa2	BBB	04/01/29	+100
79	03/25/24	PEG	Public Service Enterprise Group Inc	Unsecured	500	5.450%	Baa2	BBB	04/01/34	+122
80	03/25/24	AEE	Union Electric Company d/b/a Ameren Missouri	Secured	500	5.200%	A2	A	04/01/34	+98
81	04/01/24	XEL	Public Service Co of Colorado	Secured	450	5.350%	A1	A	05/15/34	+105
82	04/01/24	XEL	Public Service Co of Colorado	Secured	750	5.750%	A1	A	05/15/54	+130
83	04/01/24	EVRG	Evergy Metro Inc	Secured	300	5.400%	A2	A	04/01/34	+110
84	04/03/24	ENGIFP	Engie SA	Unsecured	750	5.250%	Baa1	BBB+	04/10/29	+100
85	04/03/24	ENGIFP	Engie SA	Unsecured	750	5.625%	Baa1	BBB+	04/10/34	+128
86	04/03/24	ENGIFP	Engie SA	Unsecured	500	5.875%	Baa1	BBB+	04/10/54	+148
87	04/09/24	DUK	Duke Energy Corporation	Unsecured	750	3.750%	Baa2	BBB	04/01/31	MS+120
88	04/09/24	VST	Vistra Operations Co LLC	Secured	500	6.000%	Baa3	BBB-	04/15/34	+165
89	04/11/24	RWE	RWE Finance US LLC	Unsecured	1,000	5.875%	Baa2	NR	04/16/34	+135
90	04/11/24	RWE	RWE Finance US LLC	Unsecured	1,000	6.250%	Baa2	NR	04/16/54	+160
91	04/15/24	EDF	Electricite de France SA	Unsecured	650	5.650%	Baa1	BBB	04/22/29	+105
92	04/15/24	EDF	Electricite de France SA	Unsecured	650	5.950%	Baa1	BBB	04/22/34	+135
93	04/15/24	EDF	Electricite de France SA	Unsecured	750	6.000%	Baa1	BBB	04/22/64	+185
94	04/15/24	ES	Eversource Energy	Unsecured	700	5.850%	Baa2	BBB+	04/15/31	+120
95	04/15/24	ES	Eversource Energy	Unsecured	700	5.950%	Baa2	BBB+	07/15/34	+135
96	04/29/24	DTE	DTE Energy Co	Unsecured	850	5.850%	Baa2	BBB	06/01/34	+125
97	05/02/24	AEP	Ohio Power Co	Unsecured	350	5.650%	Baa1	BBB+	06/01/34	+110
98	05/06/24	D	Dominion Energy Inc	Pref/Hybrid	1,000	6.875%	Baa3	BBB-	02/01/55	+239
99	05/06/24	D	Dominion Energy Inc	Pref/Hybrid	1,000	7.000%	Baa3	BBB-	06/01/54	+251
100	05/06/24	ED	Consolidated Edison Co of New York Inc	Unsecured	400	5.375%	A3	A-	05/15/34	+90

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending April 30, 2027

Case No.: U-21870
Exhibit No.: A-28 (MRB-9)
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Witness: MRBleckman
Date: June 2025

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	ED	Consolidated Edison Co of New York Inc	Unsecured	1,000	5.700%	A3	A-	05/15/54	+110
2	05/06/24	EXC	Commonwealth Edison Co	Secured	400	5.300%	A1	A	06/01/34	+85
3	05/06/24	EXC	Commonwealth Edison Co	Secured	400	5.650%	A1	A	06/01/54	+105
4	05/06/24	EIX	Southern California Edison Co	Secured	750	5.450%	A2	A-	06/01/31	+97
5	05/06/24	PNW	Arizona Public Service Co	Unsecured	450	5.700%	Baa1	BBB+	08/15/34	+125
6	05/06/24	ITC	ITC Holdings Corp	Unsecured	400	5.650%	Baa2	BBB+	05/09/34	+118
7	05/06/24	OGE	OGE Energy Corp	Unsecured	350	5.450%	Baa1	BBB	05/15/29	+100
8	05/07/24	EIX	SCE Trust VIII ($25 par)	Pref/Hybrid	350	6.950%	Baa3	BB+	05/13/29	+248
9	05/07/24	ETR	Entergy Arkansas LLC	Secured	400	5.450%	A2	A	06/01/34	+100
10	05/07/24	ETR	Entergy Arkansas LLC	Secured	400	5.750%	A2	A	06/01/54	+118
11	05/07/24	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	450	5.100%	A2	A-	05/06/27	+48
12	05/07/24	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	350	5.150%	A2	A-	06/15/29	+73
13	05/07/24	WEC	Wisconsin Electric Power Co	Unsecured	350	5.000%	A2	A-	05/15/29	+60
14	05/08/24	CNP	CenterPoint Energy Inc	Unsecured	700	5.400%	Baa2	BBB	06/01/29	+95
15	05/13/24	NI	NiSource	Pref/Hybrid	500	6.950%	Baa3	BBB-	11/30/54	+245
16	05/13/24	BKH	Black Hills Corporation	Unsecured	450	6.000%	Baa2	BBB+	01/15/35	+155
17	05/13/24	XEL	Northern States Power - WI	Secured	400	5.650%	Aa3	A	06/15/54	+105
18	05/13/24	ETR	Entergy Mississippi	Secured	300	5.850%	A2	A	06/01/54	+123
19	05/15/24	ONCRTX	Oncor Electric Delivery Company	Secured	500	3.500%	A2	A+	05/15/31	MS+80
20	05/16/24	AES	The AES Corp	Pref/Hybrid	950	7.600%	Ba1	BB	01/15/55	+320
21	05/20/24	ETR	Entergy Corp	Pref/Hybrid	1,200	7.125%	Baa3	BBB-	12/01/54	+267
22	05/20/24	AEP	AEP Texas Inc	Unsecured	500	5.450%	Baa2	BBB+	05/15/29	+100
23	05/20/24	AEP	AEP Texas Inc	Unsecured	350	5.700%	Baa2	BBB+	05/15/34	+130
24	05/20/24	ES	NSTAR Electric Co	Unsecured	600	5.400%	A2	A	06/01/34	+98
25	05/21/24	EVRG	Evergy Missouri West Inc	Secured	300	5.650%	A3	A	06/01/34	+125
26	05/28/24	NEE	Florida Power & Light Co	Secured	750	5.150%	Aa2	A+	06/15/29	+60
27	05/28/24	NEE	Florida Power & Light Co	Secured	750	5.300%	Aa2	A+	06/15/34	+80
28	05/28/24	NEE	Florida Power & Light Co	Secured	850	5.600%	Aa2	A+	06/15/54	+95
29	05/28/24	SRE	Sempra Energy (Reopening)	Pref/Hybrid	500	6.875%	Baa3	BBB-	10/01/54	+279
30	06/03/24	EXC	Baltimore Gas and Electric Co	Unsecured	400	5.300%	A3	A	06/01/34	+93
31	06/03/24	EXC	Baltimore Gas and Electric Co	Unsecured	400	5.650%	A3	A	06/01/54	+110
32	06/03/24	XEL	Southwestern Public Service Co	Secured	600	6.000%	A3	A-	06/01/54	+150
33	06/03/24	LNT	Alliant Energy Finance LLC	Unsecured	375	5.400%	Baa2	BBB+	06/06/27	+80
34	06/04/24	PSD	Puget Sound Energy Inc	Unsecured	400	5.330%	A2	A-	06/15/34	+100
35	06/04/24	PSD	Puget Sound Energy Inc	Unsecured	400	5.685%	A2	A-	06/15/54	+120
36	06/05/24	NEE	NextEra Energy Capital Holdings Inc	Pref/Hybrid	1,200	6.750%	Baa2	BBB	06/15/54	+246
37	06/05/24	DUK	Duke Energy Corp	Unsecured	750	5.450%	Baa2	BBB	06/15/34	+118
38	06/05/24	DUK	Duke Energy Corp	Unsecured	750	5.800%	Baa2	BBB	06/15/54	+140
39	06/05/24	AES	AES Andes SA	Pref/Hybrid	530	8.150%	Ba1	BB	06/10/55	+384
40	06/10/24	EMACN	EUSHI Finance Inc	Pref/Hybrid	500	7.625%	Ba1	BB+	12/15/54	+314
41	06/05/24	PNW	Pinnacle West Capital Corp	Unsecured	350	FRN	Baa2	BBB	06/10/26	+82
42	06/17/24	AEP	American Electric Power Co.	Pref/Hybrid	400	7.050%	Baa3	BBB-	12/15/54	+275
43	06/17/24	AEP	American Electric Power Co.	Pref/Hybrid	600	6.950%	Baa3	BBB-	12/15/54	+268
44	06/17/24	ONCRTX	Oncor Electric Delivery	Secured	750	5.550%	A2	A+	06/15/54	+115
45	06/17/24	AEE	Ameren Illinois Company	Secured	625	5.550%	A1	A	07/01/54	+115
46	06/17/24	NI	NiSource Inc	Unsecured	600	5.200%	Baa2	BBB+	07/01/29	+95
47	06/17/24	CNP	CenterPoint Energy Resources Corp	Unsecured	400	5.400%	A3	BBB+	07/01/34	+115
48	06/24/24	HASI	Hannon Armstrong Sustainable Infrastructure Capital I	Unsecured	700	6.375%	Baa3	BB+	07/01/34	+225
49	06/25/24	EIX	Edison International	Unsecured	500	5.450%	Baa2	BBB-	06/15/29	+120
50	07/15/24	NGGLN	The Brooklyn Union Gas Co (Reopening)	Unsecured	150	6.388%	Baa2	BBB+	09/15/33	+167
51	07/15/24	NGGLN	The Brooklyn Union Gas Co	Unsecured	450	6.415%	Baa2	BBB+	07/18/54	+195
52	**07/29/24**	**CMS**	**Consumers Energy Co**	**Secured**	**700**	**4.700%**	**A1**	**A**	**01/15/30**	**+68**
53	07/29/24	DTE	DTE Energy Co	Unsecured	1,200	4.950%	Baa2	BBB	7/1/2027	+80
54	08/01/24	PEG	Public Service Electric & Gas	Secured	600	4.850%	A1	A	8/1/2034	+90
55	08/01/24	PEG	Public Service Electric & Gas	Secured	500	5.300%	A1	A	8/1/2054	+105
56	08/01/24	AGR	New York State Electric & Gas Corp	Unsecured	525	5.300%	Baa1	A-	8/15/2034	+135
57	08/06/24	ETR	Entergy Louisiana LLC	Secured	700	5.150%	A2	A	09/15/34	+130
58	08/06/24	PPL	PPL Capital Funding Inc	Unsecured	750	5.250%	Baa1	BBB+	09/01/34	+143
59	08/06/24	SR	Spire Missouri Inc	Secured	320	5.150%	A1	A	08/15/34	+130
60	08/06/24	ES	The Connecticut Light and Power Co	Secured	300	4.950%	A1	A+	08/15/34	+110
61	08/06/24	D	Virginia Electric and Power Co	Unsecured	600	5.050%	A2	BBB+	08/15/34	+120
62	08/06/24	D	Virginia Electric and Power Co	Unsecured	600	5.550%	A2	BBB+	08/15/54	+140
63	08/07/24	IDA	Idaho Power Co	Secured	300	5.200%	A2	A-	08/15/34	+125
64	08/07/24	FTSCN	Tucson Electric Power Co	Unsecured	400	5.200%	A3	A-	09/15/34	+128
65	08/08/24	WTRG	Essential Utilities Inc	Unsecured	500	4.800%	Baa2	BBB+	08/15/27	+90
66	08/08/24	NRUC	National Rural Utilities Cooperative Finance Corp	Secured	350	5.000%	A1	A-	08/15/34	+110
67	08/08/24	OGS	One Gas Inc (Reopening)	Unsecured	250	5.100%	Aaa	AA+	04/01/29	+85
68	08/08/24	SRE	Southern California Gas Co	Secured	600	5.050%	Aa3	A+	09/01/34	+110
69	08/08/24	TVA	Tennessee Valley Authority	Unsecured	1,000	4.375%	Aaa	AA+	08/01/34	+48
70	08/12/24	DUK	Piedmont Natural Gas Co Inc	Secured	375	5.100%	A3	BBB+	02/15/35	+120
71	08/12/24	CNP	CenterPoint Energy	Pref/Hybrid	400	7.000%	Baa3	BBB-	02/15/55	+325
72	08/12/24	CNP	CenterPoint Energy	Pref/Hybrid	400	6.850%	Baa3	BBB-	02/15/55	+295
73	08/12/24	ETR	Entergy Texas Inc	Secured	350	5.550%	A3	A	09/15/54	+140
74	08/12/24	OGE	Oklahoma Gas and Electric Co (Reopening)	Secured	350	5.600%	A3	A-	04/01/53	+130
75	08/19/24	DUK	Duke Energy Corp	Pref/Hybrid	1,000	6.450%	Baa3	BBB-	09/01/54	+259
76	09/03/24	FE	FirstEnergy Transmission LLC	Unsecured	400	4.550%	Baa2	BBB+	01/15/30	+92
77	09/03/24	FE	FirstEnergy Transmission LLC	Unsecured	400	5.000%	Baa2	BBB+	01/15/35	+117
78	09/03/24	NI	NiSource Inc.	Pref/Hybrid	500	6.375%	Baa3	BBB-	03/31/55	+253
79	09/03/24	PCG	Pacific Gas and Electric Co	Secured	750	5.900%	Baa2	BBB	10/01/54	+180
80	09/03/24	PCG	Pacific Gas and Electric Co	Secured	1,000	FRN	Baa2	BBB	09/04/25	+95
81	09/03/24	EXC	PECO Energy Co	Secured	575	5.250%	Aa3	A	09/15/54	+112
82	09/03/24	EIX	Southern California Edison Co	Secured	500	4.400%	A2	A-	09/06/26	+55
83	09/03/24	SO	Southern Company Gas Capital Corp	Unsecured	450	4.950%	Baa1	A-	09/15/34	+115
84	09/04/24	LNT	Inerstate Power and Light	Unsecured	350	4.950%	Baa1	A-	09/30/34	+120
85	09/04/24	LNT	Inerstate Power and Light	Unsecured	300	5.450%	Baa1	A-	09/30/54	+140
86	09/04/24	SRE	Sempra	Pref/Hybrid	1,250	6.400%	Baa3	BBB-	10/01/54	+263
87	09/04/24	SO	The Southern Co	Unsecured	750	4.850%	Baa2	BBB+	03/15/35	+110
88	09/09/24	NRUC	National Rural Utilities	Unsecured	300	FRN	A2	A-	09/16/27	+100
89	09/09/24	NRUC	National Rural Utilities	Unsecured	550	4.120%	A2	A-	09/16/27	+58
90	09/09/24	NRUC	National Rural Utilities	Unsecured	500	5.150%	A2	A-	06/15/29	+73
91	09/09/24	PCG	PG&E Corporation	Pref/Hybrid	1,000	7.375%	Ba3	B	03/15/55	+388
92	09/09/24	WEC	Wisconsin Electric Power Co	Unsecured	300	4.600%	A2	A-	10/01/34	+90
93	09/09/24	WEC	Wisconsin Electric Power Co	Unsecured	300	5.050%	A2	A-	10/01/54	+108
94	09/16/24	ALACN	AltaGas Ltd	Pref/Hybrid	900	7.200%	NR	BB	10/15/54	+357
95	09/17/24	ATO	Atmos Energy Corp	Unsecured	650	5.000%	A1	A-	12/15/54	+108
96	09/26/24	NIAENE	Niagara Energy SAC	Unsecured	1,200	5.746%	Baa3	BBB-	10/03/34	+195
97	09/30/24	AEE	Union Electric Company d/b/a Ameren Missouri	Secured	450	5.125%	A2	A	03/15/55	+102
98	10/07/24	BRKHEC	Eastern Energy Gas Holdings	Unsecured	900	5.650%	Baa1	A-	10/15/54	+135
99	10/29/24	CNP	CenterPoint Energy Inc	Pref/Hybrid	500	6.700%	Baa3	BBB-	05/15/55	+259
100	10/31/24	EIX	Edison International	Unsecured	550	5.250%	Baa2	BBB-	03/15/32	+105

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending April 30, 2027

Case No.: U-21870
Exhibit No.: A-28 (MRB-9)
Page: 5 of 5
Witness: MRBleckman
Date: June 2025

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) S&P	(i) Maturity	(j) Issue Spread (bp)
1	11/08/24	ONCRTX	Oncor Electric Delivery	Secured	550	4.650%	A2	A+	11/01/29	+52
2	11/13/24	PCG	PG&E Corporation (Reopening)	Pref/Hybrid	500	7.375%	Ba3	BBB-	03/15/55	+388
3	11/14/24	ED	Consolidated Edison Co of New York	Unsecured	350	FRN	A3	A-	11/18/27	+52
4	11/14/24	ED	Consolidated Edison Co of New York	Unsecured	450	5.125%	A3	A-	03/15/35	+70
5	11/14/24	ED	Consolidated Edison Co of New York	Unsecured	650	5.500%	A3	A-	03/15/55	+70
6	11/14/24	D	Dominion Energy	Pref/Hybrid	1,250	6.625%	Baa3	BBB-	05/15/55	+221
7	11/18/24	SRE	Sempra	Pref/Hybrid	400	6.625%	Baa3	BBB-	04/01/55	+235
8	11/18/24	SRE	Sempra	Pref/Hybrid	600	6.550%	Baa3	BBB-	04/01/55	+214
9	11/19/24	VST	Vistra Operations Co	Secured	500	5.050%	Baa3	BBB-	12/30/26	+80
10	11/19/24	VST	Vistra Operations Co	Secured	750	5.700%	Baa3	BBB-	12/30/34	+133
11	11/21/24	BIP	Brookfield Infrastructure Finance ULC	Pref/Hybrid	300	6.750%	NR	BBB-	03/15/55	+245
12	12/02/24	EVRG	Evergy Inc.	Pref/Hybrid	500	6.650%	Baa3	BBB-	06/01/55	+256
13	12/02/24	FE	Jersey Central Power & Light Co	Unsecured	700	5.100%	A3	BBB	01/15/35	+95
14	12/02/24	SO	Georgia Power Co	Unsecured	600	4.550%	A3	A	03/15/30	+52
15	12/02/24	WEC	Wisconsin Public Service	Unsecured	300	4.550%	A2	A-	12/01/29	+48
16	12/03/24	AEP	Public Service Co of Oklahoma	Unsecured	600	5.200%	Baa1	BBB+	01/15/35	+100
17	12/03/24	ETR	System Energy Resources Inc	Secured	300	5.300%	Baa2	BBB+	12/15/34	+113
18	12/04/24	AES	The AES Corporation	Pref/Hybrid	500	6.950%	Ba1	BB	07/15/55	+289
19	12/09/24	HASI	Hannon Armstrong Sustainable Infrastructure Capital I	Unsecured	300	6.375%	Baa3	BB+	07/01/34	+220
20	01/02/25	D	Dominon Energy South Carolina	Secured	450	5.300%	A2	A	01/15/35	+75
21	01/02/25	DUK	Duke Energy Carolinas	Secured	400	4.850%	Aa3	A	03/15/30	+50
22	01/02/25	DUK	Duke Energy Carolinas	Secured	700	5.250%	Aa3	A	03/15/35	+72
23	01/02/25	ETR	Entergy Louisiana	Secured	750	5.800%	A2	A	03/15/35	+103
24	01/06/25	EIX	Southern California Edison Company	Secured	850	5.450%	A2	A-	03/01/35	+85
25	01/06/25	EIX	Southern California Edison Company	Secured	650	5.900%	A2	A-	03/01/55	+108
26	01/06/25	ES	Connecticut Light & Power Company	Secured	400	4.950%	A1	A	01/15/30	+55
27	01/07/25	NGGLN	Boston Gas Company	Unsecured	500	5.843%	Baa1	BBB+	01/10/35	+115
28	01/08/25	SO	Southern Company ($25 par)	Pref/Hybrid	565	6.500%	Baa2	BBB	03/15/85	-
29	01/13/25	BRKHEC	Eastern Energy Gas Holdings	Unsecured	700	5.800%	Baa1	A-	01/15/35	+105
30	01/13/25	BRKHEC	Eastern Energy Gas Holdings	Unsecured	500	6.200%	Baa1	A-	01/15/55	+125
31	01/27/25	KALLPA	Kallpa Generacion SA	Unsecured	500	5.875%	Baa3	NR	01/30/32	+163
32	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	500	FRN	Baa1	BBB+	02/04/28	+80
33	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	1,000	4.850%	Baa1	BBB+	02/04/28	+60
34	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	1,000	5.050%	Baa1	BBB+	03/15/30	+73
35	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	750	5.300%	Baa1	BBB+	03/15/32	+88
36	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	1,000	5.450%	Baa1	BBB+	03/15/35	+98
37	01/30/25	NEE	NextEra Energy Capital Holdings Inc.	Unsecured	750	5.900%	Baa1	BBB+	03/15/55	+113
38	01/30/25	BRKHEC	Nevada Power Company	Pref/Hybrid	300	6.250%	Baa2	BBB-	05/15/55	+194
39	02/04/25	NEE	NextEra Energy Capital Holdings Inc.	Pref/Hybrid	1,500	6.375%	Baa2	BBB	08/15/55	+205
40	02/04/25	NEE	NextEra Energy Capital Holdings Inc.	Pref/Hybrid	1,000	6.500%	Baa2	BBB	08/15/55	+198
41	02/05/25	NFG	National Fuel Gas Co	Unsecured	500	5.500%	Baa3	BBB-	03/15/30	+118
42	02/05/25	NFG	National Fuel Gas Co	Unsecured	500	5.950%	Baa3	BBB-	03/15/35	+147
43	02/05/25	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	600	4.750%	A2	A-	02/07/28	+52
44	02/05/25	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	500	4.950%	A2	A-	02/07/30	+67
45	02/13/25	EXC	Exelon Corporation	Pref/Hybrid	1,000	6.500%	Baa3	BBB	03/15/55	+198
46	02/18/25	CMS	CMS Energy Corporation	Pref/Hybrid	1,000	6.500%	Baa3	BBB-	06/01/55	+196
47	02/18/25	EXC	Exelon Corporation	Unsecured	500	5.125%	Baa2	BBB+	03/15/31	+75
48	02/18/25	EXC	Exelon Corporation	Unsecured	500	5.875%	Baa2	BBB+	03/15/55	+113
49	02/18/25	NEE	Florida Power and Light (Reopening)	Secured	350	5.300%	Aa2	A+	06/15/34	+73
50	02/18/25	NEE	Florida Power and Light	Secured	950	5.700%	Aa2	A+	03/15/55	+93
51	02/18/25	NEE	Florida Power and Light	Secured	700	5.800%	Aa2	A+	03/15/65	+103
52	02/18/25	FTSCN	Tucson Electric Power	Unsecured	300	5.900%	A3	A-	04/15/55	+115
53	02/18/25	DTE	DTE Energy	Unsecured	1,100	5.200%	Baa2	BBB	04/01/30	+85
54	02/24/25	SO	Georgia Power Company	Unsecured	400	FRN	A3	A	09/15/26	+28
55	02/24/25	SO	Georgia Power Company	Unsecured	500	4.850%	A3	A	03/15/31	+65
56	02/24/25	SO	Georgia Power Company	Unsecured	700	5.200%	A3	A	03/15/35	+83
57	02/24/25	PCG	Pacific Gas & Electric	Secured	1,000	5.700%	Baa2	BBB	03/01/35	+130
58	02/24/25	PCG	Pacific Gas & Electric	Secured	750	6.150%	Baa2	BBB	03/01/55	+150
59	02/24/25	ES	NSTAR Electric	Unsecured	400	4.850%	A2	A-	03/01/30	+65
60	02/24/25	ES	NSTAR Electric	Unsecured	400	5.200%	A2	A-	03/01/35	+85
61	02/24/25	AWK	American Water Company	Unsecured	800	5.250%	Baa1	A	03/01/35	+90
62	02/24/25	CNP	CenterPoint Energy Houston Electric	Secured	500	4.800%	A2	A	03/15/30	+60
63	02/24/25	ETR	Entergy Texas	Secured	500	5.250%	A3	A	04/15/35	+88
64	02/24/25	AEE	Ameren Illinois	Secured	350	5.625%	A1	A	03/01/55	+95
65	02/25/25	SO	Southern Company	Pref/Hybrid	1,800	6.375%	Baa2	BBB	03/15/55	+207
66	02/27/25	PEG	Public Service Electric Gas & Co	Secured	400	5.050%	A1	A	03/01/35	+78
67	02/27/25	PEG	Public Service Electric Gas & Co	Secured	500	5.500%	A1	A	03/01/55	+98
68	02/27/25	AEE	Ameren Corporation	Unsecured	750	5.375%	Baa1	BBB	03/15/35	+110
69	03/03/25	DUK	Duke Energy Progress	Secured	500	4.350%	Aa3	A	03/06/27	+40
70	03/03/25	DUK	Duke Energy Progress	Secured	850	5.050%	Aa3	A	03/15/35	+90
71	03/03/25	DUK	Duke Energy Progress	Secured	750	5.550%	Aa3	A	03/15/55	+110
72	03/03/25	TE	Tampa Electric	Unsecured	600	5.150%	A3	BBB+	03/01/35	+100
73	03/06/25	PEG	Public Service Enterprise Group	Unsecured	600	4.900%	Baa2	BBB	03/15/30	+115
74	03/06/25	PEG	Public Service Enterprise Group	Unsecured	400	5.400%	Baa2	BBB	03/15/35	+140
75	03/06/25	EVRG	Evergy Kansas Central	Secured	300	4.700%	Baa1	BBB+	03/15/28	+73
76	03/06/25	EVRG	Evergy Kansas Central	Secured	300	5.250%	Baa1	BBB+	03/15/35	+100
77	03/06/25	D	Dominion Energy	Unsecured	800	5.000%	Baa2	BBB	06/15/30	+95
78	03/06/25	D	Dominion Energy	Unsecured	700	5.450%	Baa2	BBB	03/15/35	+120
79	03/10/25	PSD	Puget Energy Inc.	Secured	600	5.725%	Baa3	BBB-	03/15/35	+150
80	03/10/25	ETR	Entergy Mississippi	Secured	600	5.800%	A2	A	04/15/55	+125
81	03/10/25	IDA	Idaho Power Co	Secured	400	5.700%	A2	A-	03/15/55	+120
82	03/11/25	EIX	Edison International	Unsecured	550	6.250%	Baa2	BBB-	03/15/30	+250
83	03/11/25	AES	AES Andes SA	Unsecured	400	6.250%	Baa3	BBB-	03/14/32	+210
84	03/12/25	EIX	Southern California Edison Co	Secured	650	5.250%	A2	A-	03/15/30	+118
85	03/12/25	EIX	Southern California Edison Co	Secured	850	6.200%	A2	A-	09/15/55	+160
86	03/12/25	AES	AES Corp	Unsecured	800	5.800%	Baa3	BBB-	03/15/32	+160
87	03/12/25	NWN	Northwest Natural Holding Co	Pref/Hybrid	325	7.000%	NR	BBB	09/15/55	+270
88	03/17/25	XEL	Public Service Co of Colorado (reopening)	Secured	400	5.350%	A1	A	05/15/34	+108
89	03/17/25	XEL	Public Service Co of Colorado	Secured	600	5.850%	A1	A	05/15/55	+125
90	03/17/25	ONCRTX	Oncor Electric Delivery	Secured	500	4.500%	A2	A+	03/20/27	+45
91	03/17/25	ONCRTX	Oncor Electric Delivery	Secured	650	5.350%	A2	A+	04/01/35	+105
92	03/17/25	ONCRTX	Oncor Electric Delivery	Secured	650	5.800%	A2	A+	04/01/55	+120
93	03/18/25	BRKHEC	PacifiCorp	Pref/Hybrid	850	7.375%	Baa2	BBB-	09/15/55	+332
94	03/18/25	XEL	Xcel Energy	Unsecured	350	4.750%	Baa1	BBB	03/15/28	+85
95	03/18/25	XEL	Xcel Energy	Unsecured	750	5.600%	Baa1	BBB	02/15/35	+135
96	03/20/25	NI	NiSource Inc.	Unsecured	750	5.850%	Baa2	BBB+	04/01/55	+130
97	03/20/25	SO	Alabama Power Company	Unsecured	500	5.100%	A1	A	04/02/35	+88
98	03/24/25	OGE	Oklahoma Gas & Electric	Unsecured	350	5.800%	A3	A-	04/01/55	+118
99	03/24/25	SRE	San Diego Gas & Electric	Secured	850	5.400%	A1	A	04/15/35	+110
100	03/26/25	AEE	Union Electric Company	Secured	500	5.250%	A2	A	04/15/35	+92
101	04/14/25	FE	Trans-Allegheny Interstate Line Co	Unsecured	600	5.000%	A3	A-	01/15/31	+100

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Peer Company Commission Authorized Equity Ratios
for the Projected Year Ending April 30, 2027

Case No.: U-21870
Exhibit No.: A-29 (MRB-10)
Page: 1 of 1
Witness: MRBleckman
Date: June 2025

(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-124	Electric	11/09/23	55.09%
3	Illinois	Ameren Corporation	Ameren Illinois Company	D-23-0082	Electric	12/14/23	50.08%
4	Arkansas	American Electric Power Company, Inc.	Southwestern Electric Power Company	D-21-070-U	Electric	05/23/22	45.86%
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-2023-00159	Electric	01/19/24	43.94%
7	Ohio	American Electric Power Company, Inc.	Ohio Power Company	C-20-0585-EL-AIR	Electric	11/17/21	54.43%
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	Alaska	Avista Corporation	Alaska Electric Light and Power Company	D-U-22-078	Electric	08/31/23	60.70%
14	Idaho	Avista Corporation	Avista Corporation	C-AVU-G-23-01	Natural Gas	08/31/23	50.00%
15	Oregon	Avista Corporation	Avista Corporation	D-UG-461	Natural Gas	10/26/23	50.00%
16	Washington	Avista Corporation	Avista Corporation	D-UG-240007	Natural Gas	12/20/24	48.50%
17	South Carolina	Dominion Energy, Inc.	Dominion Energy South Carolina, Inc.	D-2024-34-E	Electric	08/08/24	52.51%
18	North Carolina	Dominion Energy, Inc.	Virginia Electric and Power Company	E-22, Sub 694	Electric	01/14/25	52.50%
19	Virginia	Dominion Energy, Inc.	Virginia Electric and Power Company	C-PUR-2021-00058	Electric	11/18/21	52.85%
20	North Carolina	Duke Energy Corporation	Duke Energy Carolinas, LLC	D-E-7 Sub 1276	Electric	12/15/23	52.50%
21	South Carolina	Duke Energy Corporation	Duke Energy Carolinas, LLC	D-2023-388-E	Electric	06/20/24	51.21%
22	Florida	Duke Energy Corporation	Duke Energy Florida, LLC	D-20240025-EI	Electric	08/21/24	53.00%
23	Indiana	Duke Energy Corporation	Duke Energy Indiana, LLC	Ca-46038	Electric	01/29/25	53.03%
24	Kentucky	Duke Energy Corporation	Duke Energy Kentucky, Inc.	C-2022-00372	Electric	10/12/23	54.19%
25	Ohio	Duke Energy Corporation	Duke Energy Ohio, Inc.	C-22-0507-GA-AIR	Natural Gas	11/01/23	52.32%
26	North Carolina	Duke Energy Corporation	Duke Energy Progress, LLC	D-E-2 Sub 1300	Electric	08/18/23	53.00%
27	South Carolina	Duke Energy Corporation	Duke Energy Progress, LLC	D-2022-254-E	Electric	02/09/23	52.43%
28	North Carolina	Duke Energy Corporation	Piedmont Natural Gas Company, Inc.	D-G-9 Sub 837	Natural Gas	01/07/25	52.73%
29	South Carolina	Duke Energy Corporation	Piedmont Natural Gas Company, Inc.	D-2023-7-G	Natural Gas	10/05/23	53.13%
30	Tennessee	Duke Energy Corporation	Piedmont Natural Gas Company, Inc.	D-23-00035	Natural Gas	12/04/23	52.48%
31	Arkansas	Entergy Corporation	Entergy Arkansas, LLC	D-16-036-FR	Electric	12/13/24	48.15%
32	Texas	Entergy Corporation	Entergy Texas, Inc.	D-53719	Electric	08/03/23	51.21%
33	Oregon	IDACORP, Inc.	Idaho Power Company	D-UE-426	Electric	09/23/24	50.00%
34	Montana	NorthWestern Corporation	NorthWestern Energy Group, Inc.	D-2022-7-78	Electric	10/25/23	48.02%
35	Arkansas	OGE Energy Corp.	Oklahoma Gas and Electric Company	D-18-046-FR	Electric	03/07/24	51.73%
36	Oklahoma	OGE Energy Corp.	Oklahoma Gas and Electric Company	PUD2023-000087	Electric	11/26/24	53.50%
37	Arizona	Pinnacle West Capital Corporation	Arizona Public Service Company	D-E-01345A-22-0144	Electric	03/05/24	51.93%
38	New Mexico	TXNM Energy	Public Service Company of New Mexico	C-22-00270-UT	Electric	01/03/24	49.61%
39	Oregon	Portland General Electric Company	Portland General Electric Company	D-UE-435	Electric	12/20/24	50.00%
40	Georgia	Southern Company	Atlanta Gas Light Company	D-42315	Natural Gas	11/18/21	56.00%
41	Tennessee	Southern Company	Chattanooga Gas Company	D-24-00024	Natural Gas	08/12/24	52.54%
42	Georgia	Southern Company	Georgia Power Company	D-44280	Electric	12/20/22	56.00%
43	Mississippi	Southern Company	Mississippi Power Company	D-2019-UN-0219	Electric	03/17/20	53.00%
44	Illinois	Southern Company	Northern Illinois Gas Company	D-23-0066	Natural Gas	11/16/23	51.57%
45	Virginia	Southern Company	Virginia Natural Gas, Inc.	C-PUR-2020-00095	Natural Gas	09/14/21	53.83%
46	Colorado	Xcel Energy Inc.	Public Service Company of Colorado	D-24AL-0049G	Natural Gas	10/25/24	56.02%
47	Minnesota	Xcel Energy Inc.	Northern States Power Company	D-G-002/GR-23-413	Natural Gas	02/13/25	52.83%
48	North Dakota	Xcel Energy Inc.	Northern States Power Company	C-PU-23-367	Natural Gas	11/07/24	52.56%
49	New Mexico	Xcel Energy Inc.	Southwestern Public Service Company	C-22-00286-UT	Electric	10/19/23	54.70%
50	Texas	Xcel Energy Inc.	Southwestern Public Service Company	D-49831	Electric	08/27/20	54.62%
51	Wisconsin	Xcel Energy Inc.	Northern States Power Company	D-4220-UR-126	Natural Gas	11/09/23	53.16%
	Average Equity Ratio						**51.85%**

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, 2020 through April 15, 2025.
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, 2027

Case No.: U-21870
Exhibit No.: A-30 (MRB-11)
Page: 1 of 1
Witness: MRBleckman
Date: June 2025

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	52.42%	10.15%	5.32%
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%	9.90%	4.95%

Source: Columns (a)-(c): March 2025 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.

Equity Research

WELLS FARGO

Industry Update — December 8, 2023

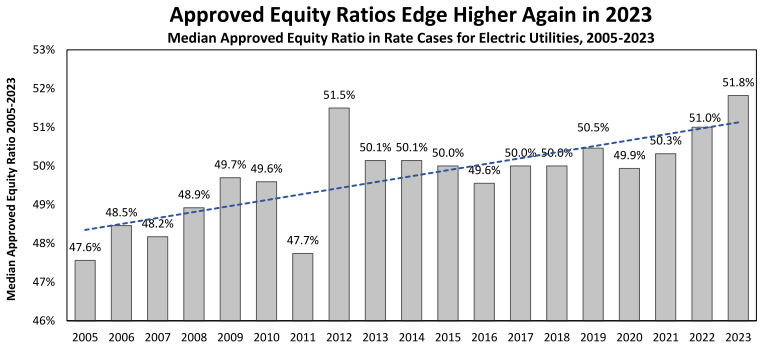
Utilities

Figure of the Week: Approved Equity Ratios, 2005-2023

Our Call

Figure of the Week

Click image to enlarge in HTML view.



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OW=Overweight: Total return on stock expected to be 10%+ over the next 12 months. BUY

EW=Equal Weight: Total return on stock expected to be -10% to +10% over the next 12 months. HOLD

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NR=Not Rated: The rating and price target has been removed due to lack of fundamental basis to support the recommendation or due to legal, regulatory or company policy considerations.

As of December 7, 2023
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44.0% of companies covered by Wells Fargo Securities, LLC Equity Research are rated Equal Weight.
6.9% of companies covered by Wells Fargo Securities, LLC Equity Research are rated Underweight.
Wells Fargo Securities, LLC has provided investment banking services for 30.8% of its Equity Research Overweight-rated companies.
Wells Fargo Securities, LLC has provided investment banking services for 30.4% of its Equity Research Equal Weight-rated companies.
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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cumulative Annual Interest Savings
for the Projected Year Ending April 30, 2027

Case No.: U-21870
Exhibit No.: A-32 (MRB-13)

Witness: MRBleckman
Date: June 2025

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)
Line			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
1	S&P Senior Secured Debt Credit Rating		BBB-	BBB	BBB	BBB	BBB+	BBB+	BBB+	A-	A	A	A	A	A	A	A	A	A	A	A	
2	Debt Issued - First Mortgage Bonds ($ millions)	A		$ -	$ 600	$ 500	$ 600	$ -	$ 725	$ 750	$ 500	$ 250	$ 450	$ 535	$ 1,900	$1,001	$ 1,661	$ 335	$ 800	$ 2,025	$ 1,300	$13,931
3	Interest Spread Differential vs. BBB-	B		1.31%	1.31%	1.31%	0.93%	0.99%	1.24%	0.82%	0.82%	0.53%	0.72%	0.61%	1.71%	0.85%	0.74%	0.56%	0.89%	1.32%	1.24%	
4	Annual Interest Savings ($ millions)	A x B		$ -	$ 8	$ 7	$ 6	$ -	$ 9	$ 6	$ 4	$ 1	$ 3	$ 3	$ 32	$ 8	$ 12	$ 2	$ 7	$ 27	$ 16	
5	Cumulative Annual Interest Savings ($ millions)			$ -	$ 8	$ 14	$ 20	$ 20	$ 29	$ 35	$ 39	$ 41	$ 44	$ 47	$ 80	$ 88	$ 100	$ 102	$ 109	$ 136	$ 152	**$ 152**
															Annual savings repeats throughout entire life of the debt.							
6	BBB- Rating Issuance Spread	C	N/A	N/A	NMF	4.40%	2.17%	2.55%	2.47%	1.71%	1.69%	1.63%	1.83%	1.47%	2.64%	1.97%	2.01%	1.35%	2.29%	2.69%	2.32%	
7	Current Rating Issuance Spread (Line 2)	D	N/A	N/A	NMF	3.09%	1.24%	1.56%	1.23%	0.90%	0.87%	1.11%	1.11%	0.86%	0.93%	1.12%	1.27%	0.79%	1.39%	1.37%	1.08%	
8	Issuance Spread Differential vs. BBB-	C - D	-	-	-	1.31%	0.93%	0.99%	1.24%	0.82%	0.82%	0.53%	0.72%	0.61%	1.71%	0.85%	0.74%	0.56%	0.89%	1.32%	1.24%	

Source: All issuance spreads per the Barclays Bank Utility Deal listing. Initial data began during calendar year 2008. 2024 represents deals year to date as of October 25, 2024.
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.

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.

To learn more or to request a demo, visit spglobal.com/marketintelligence.

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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.

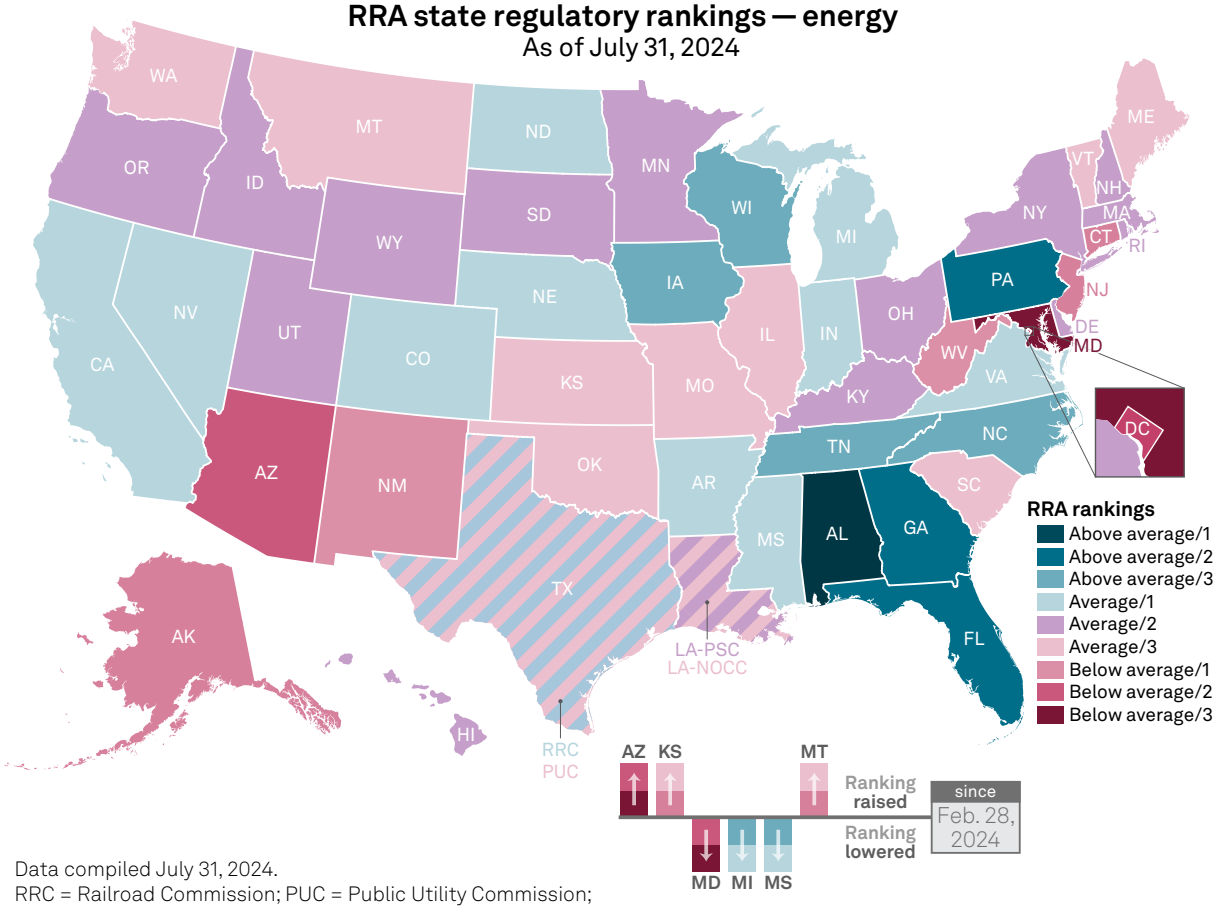
The Take

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.

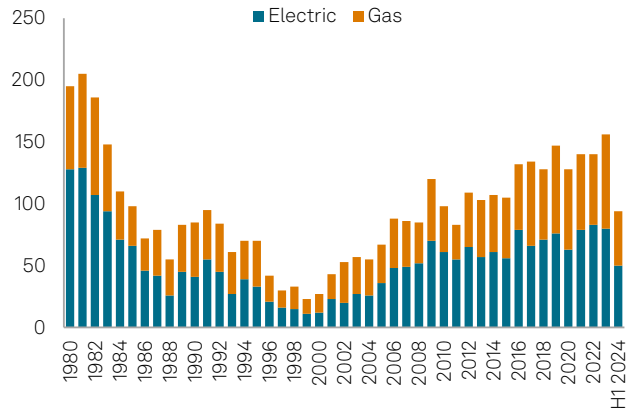
Outlook

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.

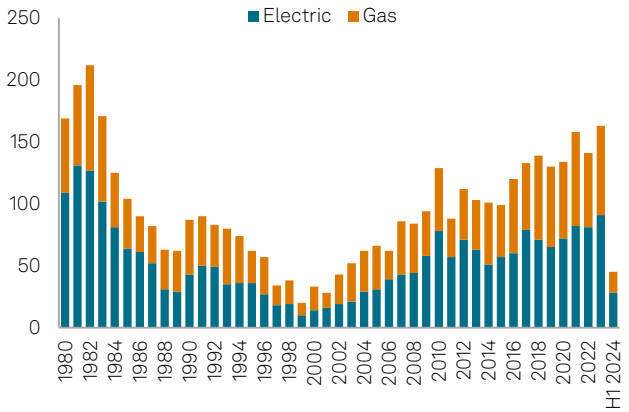
There were 164 electric and gas rate cases decided for the US investor-owned energy utilities in RRA's coverage universe during 2023, with an aggregate $9.3 billion of rate increases approved in those cases. During the first half of 2024, 45 cases were decided, netting $2.3 billion in rate increases.

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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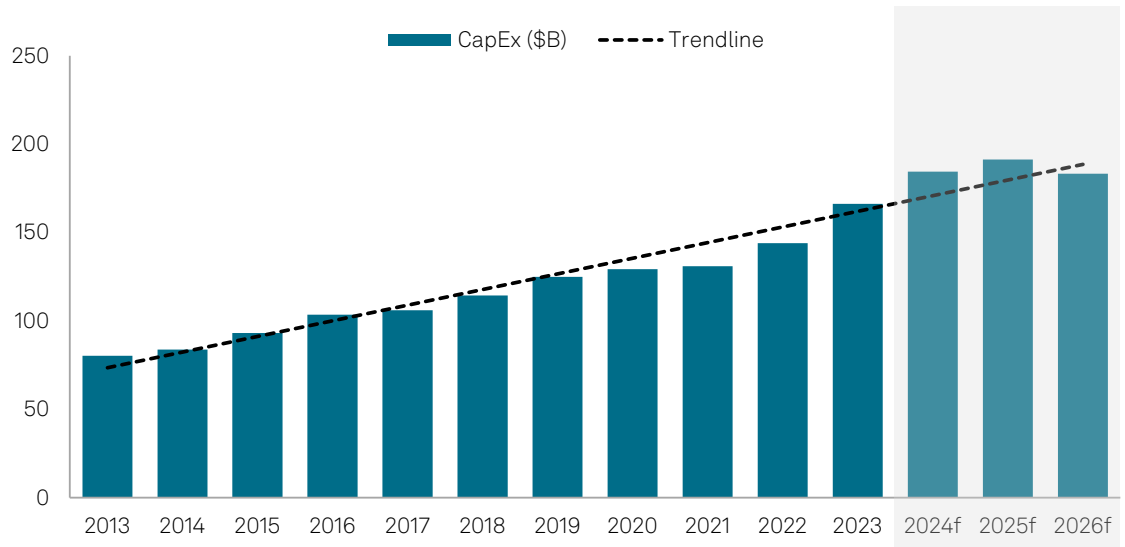
RRA anticipates this trend of robust rate case activity will persist for the foreseeable future, driven by continued expansion in capital spending.

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.

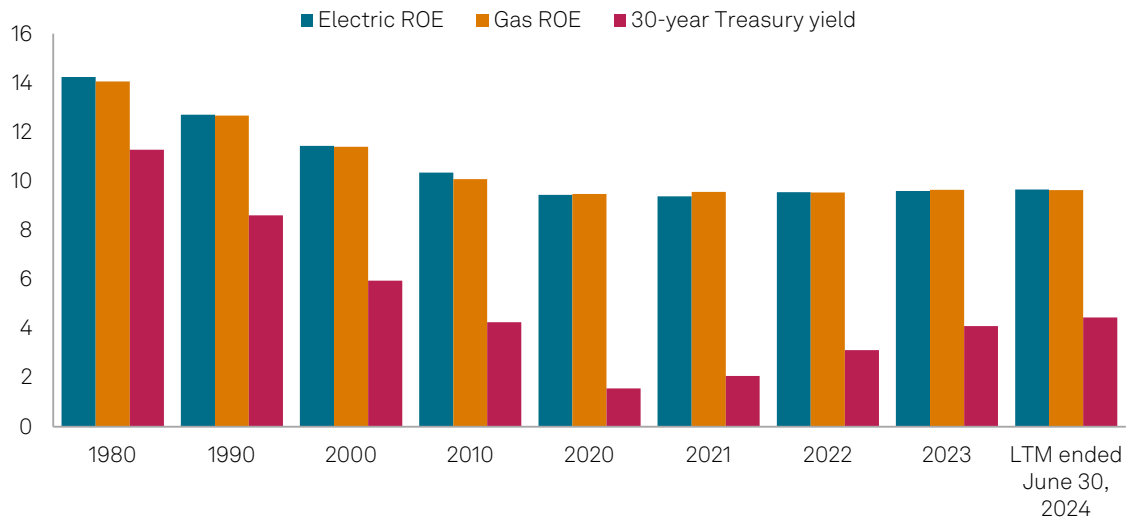
The need to recover the related costs, together with the previously listed factors, will continue to put upward pressure on rates, exacerbating prevailing concerns about ratepayer impacts and affordability, and rendering it challenging for companies to reflect higher financing costs in their authorized 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.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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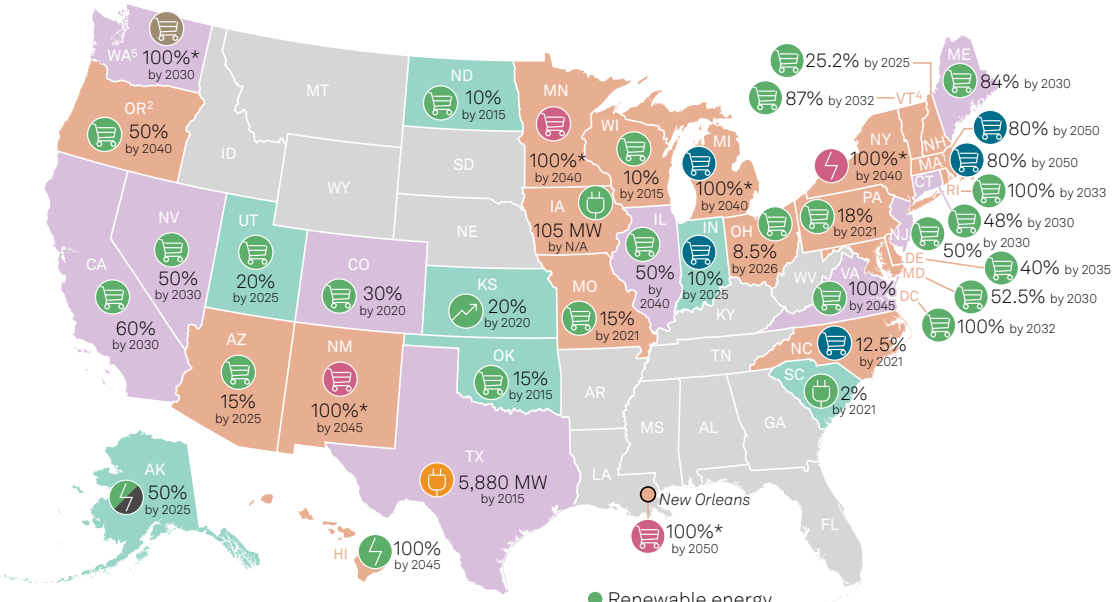
The evolving energy transition presents unique challenges for the electric and gas utility sector, but also offers potential for growth. Much of the evolution has come via state legislative initiatives and energy issues continue to be a focus in the current legislative session.

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



- Mandatory renewable, clean energy standards
- Nonbinding energy goals
- Additional goals on top of a mandatory standard

- Renewable energy
- Clean energy
- Carbon-free
- Greenhouse gas neutral
- Alternative energy
- Solar energy

- Electric generation
- Installed capacity
- Peak demand
- Retail sales

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.
Design credit: Cat VanVliet.
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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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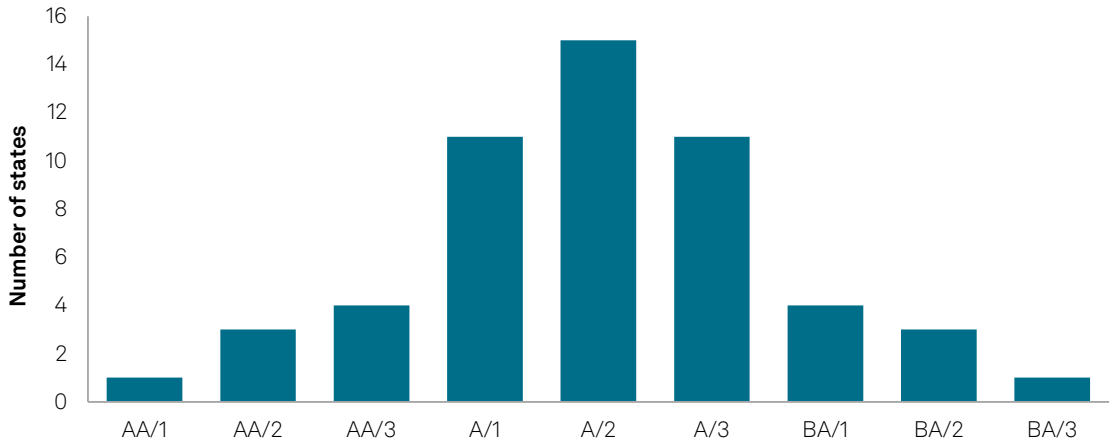
As implied by the above discussion, the rankings reflect the state regulatory commission's decisions and the impact of the actions taken by the governor, the legislature, the courts and consumer advocacy groups. The policies examined pertain largely to rate cases and the ratemaking process, but RRA also 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.

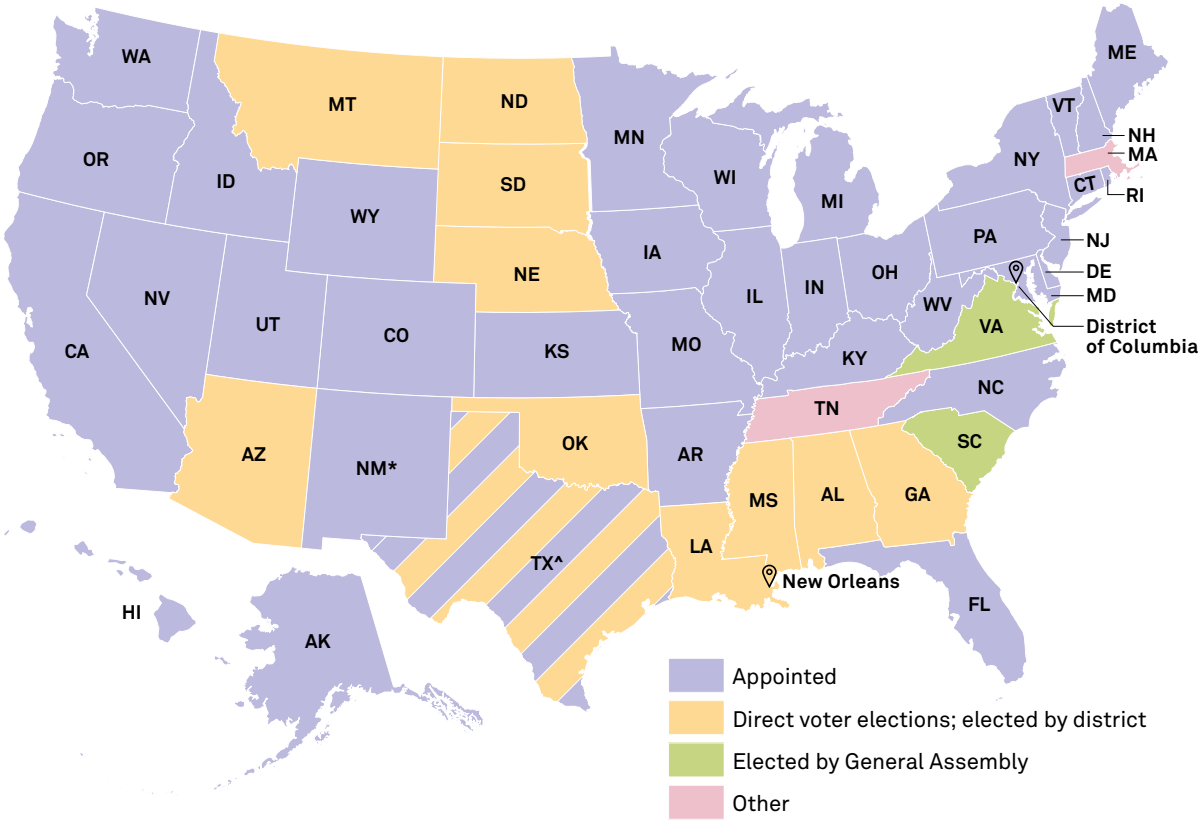
Overview of issues considered in the ranking process

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.

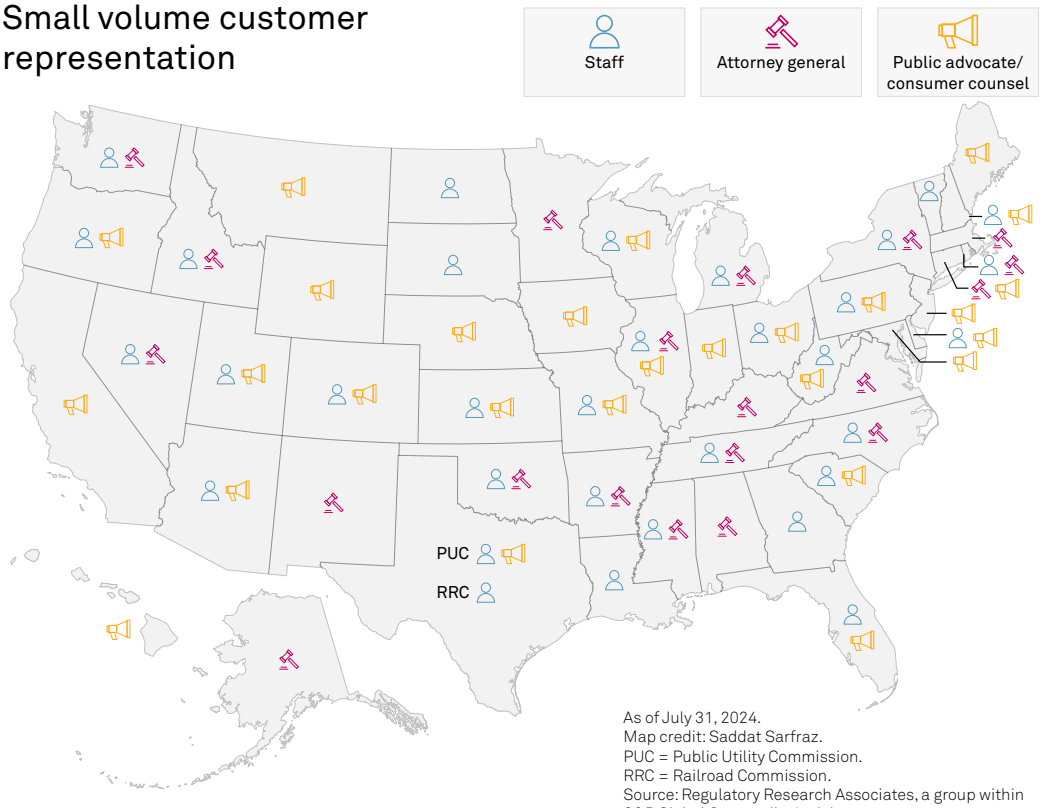
In addition, RRA looks at the commissioners themselves and their backgrounds. Experience in economics and finance and/or energy issues is generally seen as a positive sign. Previous employment by the commission or a consumer advocacy group is sometimes viewed as a negative indicator.

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.

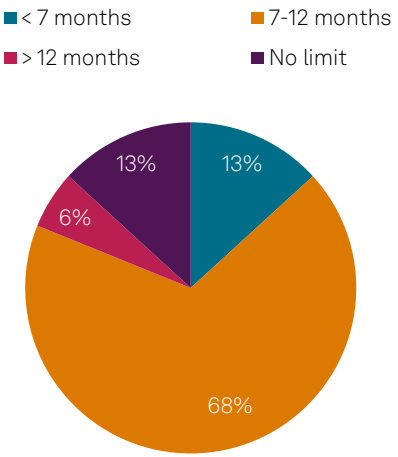
In addition, a shorter time frame for a decision generally reduces the likelihood that the actual conditions, during the first year the new rates will be in effect, will vary markedly from the test period utilized to set new rates, thus keeping regulatory lag to a minimum.

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



Data compiled as of July 31, 2024.
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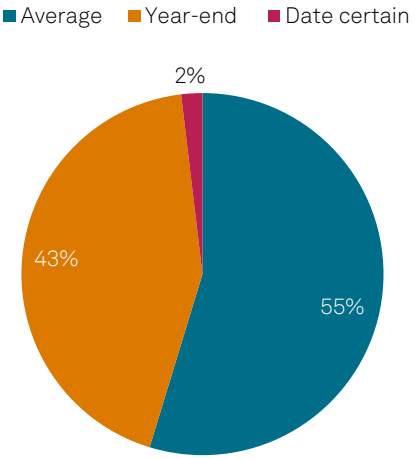
Rate base — A utility's rate base is essentially the company's "prudent" capital investment as determined by the applicable regulatory authorities, net of accumulated depreciation and other adjustments. Rate base is the net asset base of an electric, gas or water utility upon which an allowed rate of 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



Data compiled July 31, 2024.
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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.

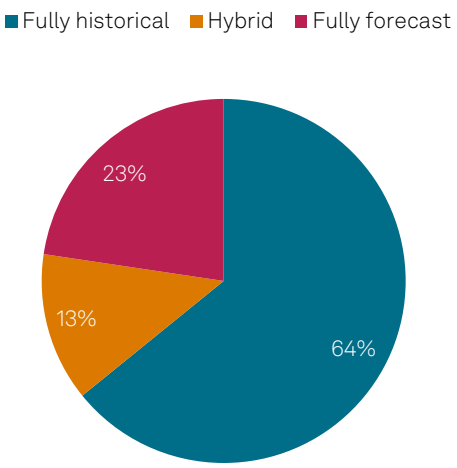
A fully forecast test year is generally considered to be most constructive, particularly in periods of robust capital spending, high inflation and rising interest rates.

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.
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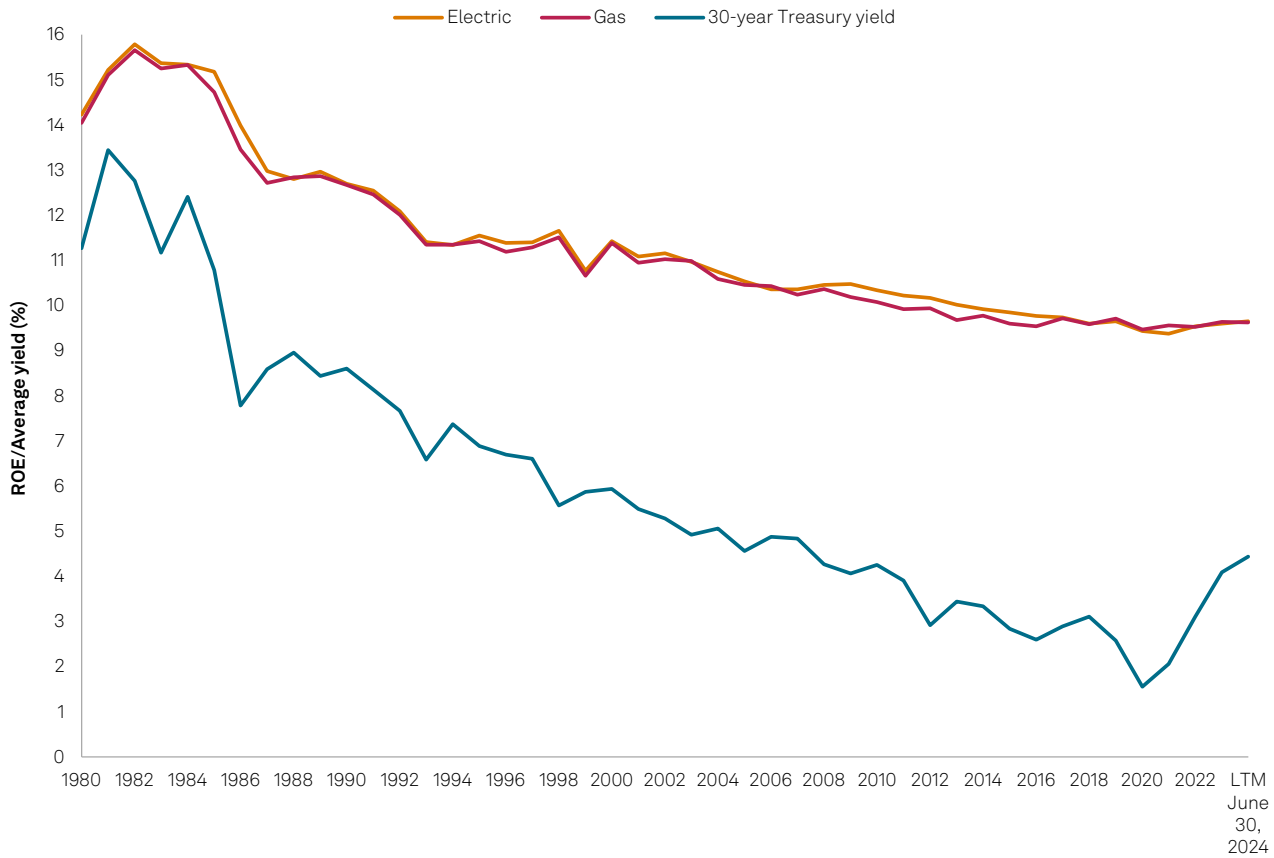
Conversely, in periods where there is only a modest amount of capital spending, i.e., depreciation is outpacing new spending, low inflation and falling interest rates, the use of a historical test year and the associated regulatory lag would work in the utility's favor, as rates would likely reflect 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.

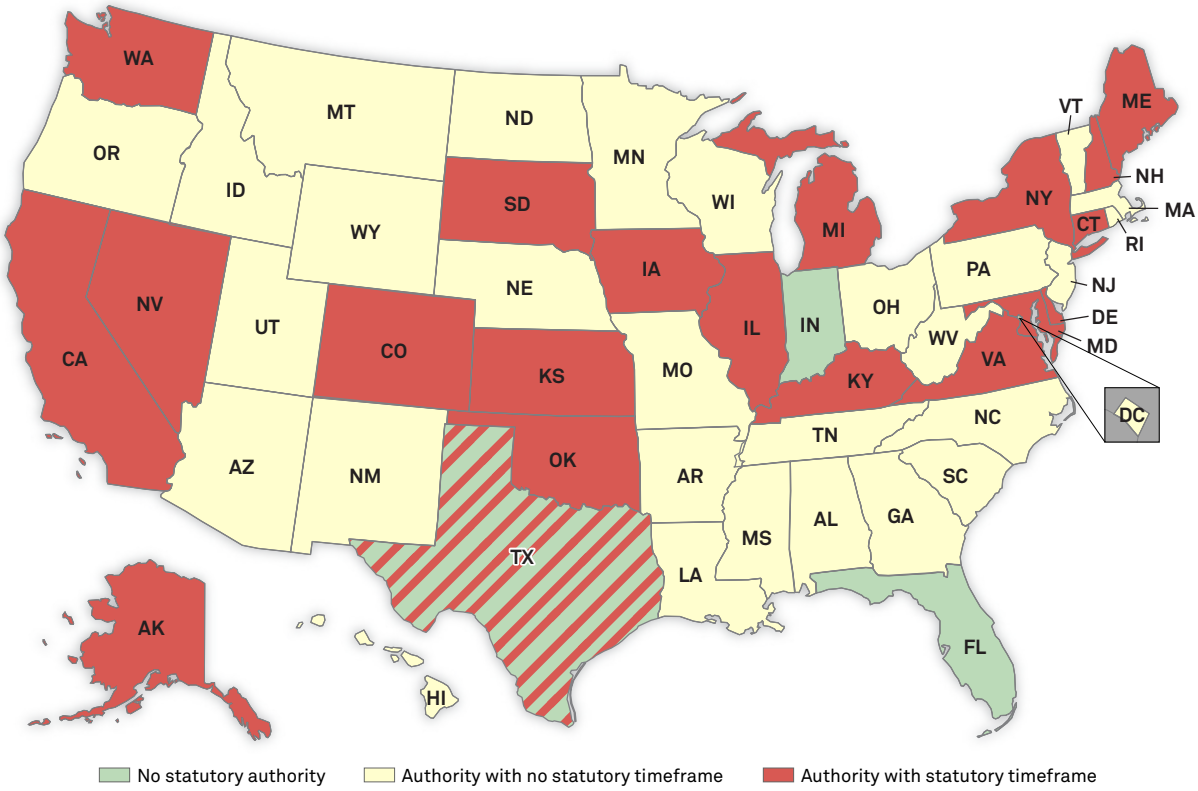
Deals involving regulated utilities are subject to review by all but three of the 53 state-level jurisdictions followed RRA follows.

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.

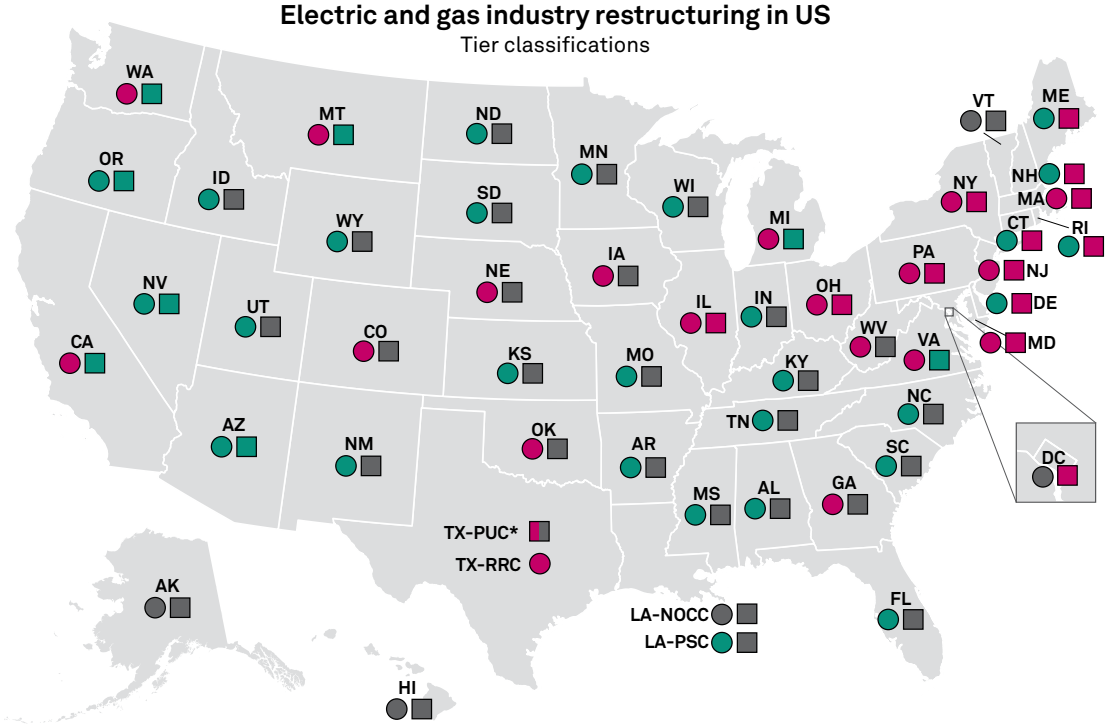
In addition, RRA considers whether the parties reached a settlement and, if so, whether the commission honored that settlement or required additional commitments. RRA also examines how politicized the process was: Did the governor (or the mayor in the District of Columbia and the City of New Orleans) 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.

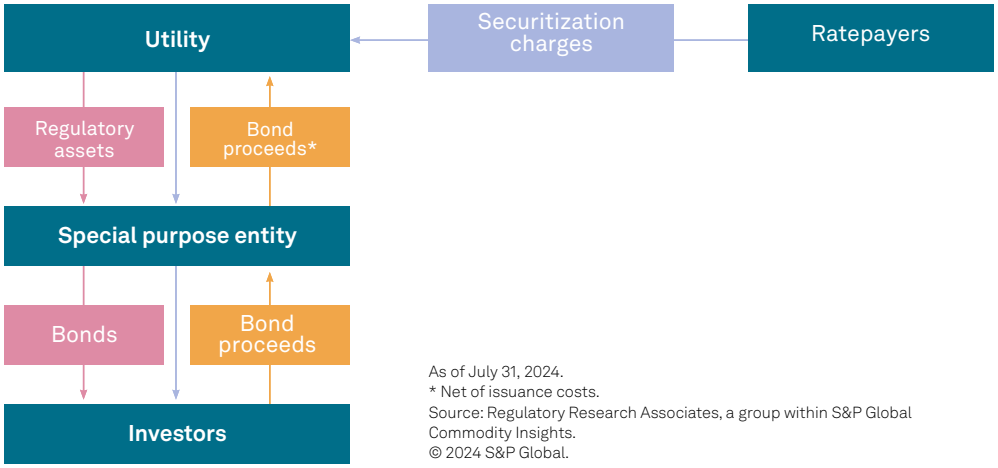
Gas regulatory reform/industry restructuring — Retail competition for gas supply is more widespread than electric retail competition, and the transition was far less contentious, as the magnitude of stranded asset costs was much smaller due to the more disaggregated structure of the industry.

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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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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10 May 2023

US Utilities

Pricing Power Analysis and Regulatory Rankings

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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.

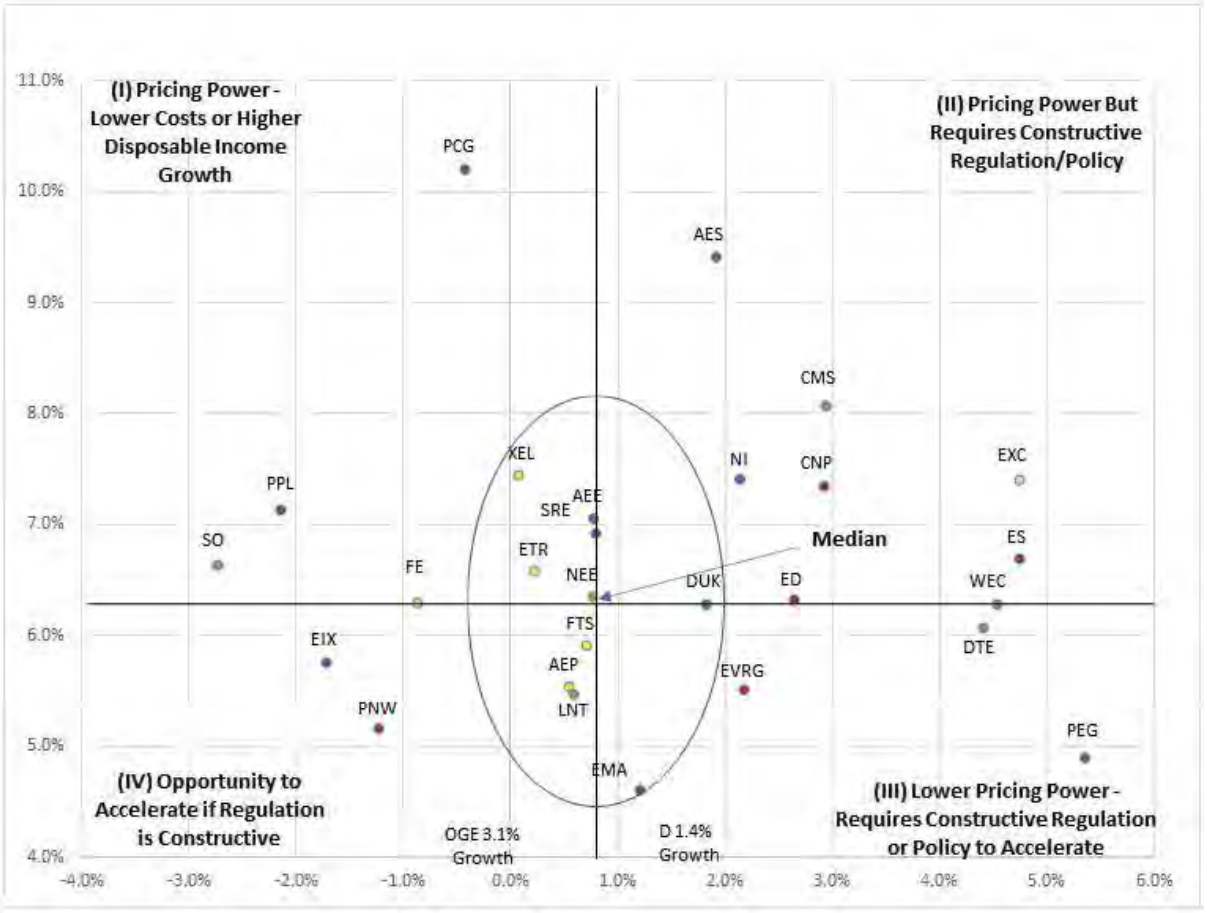
Dividing annual bills by weighted average disposable income projected into 2029 and seeing how much that grew versus the same metric in 2021, and annualizing that growth provides a measure of bill affordability inflation. When we graph this against annualized projected utility and parent only EPS growth, 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



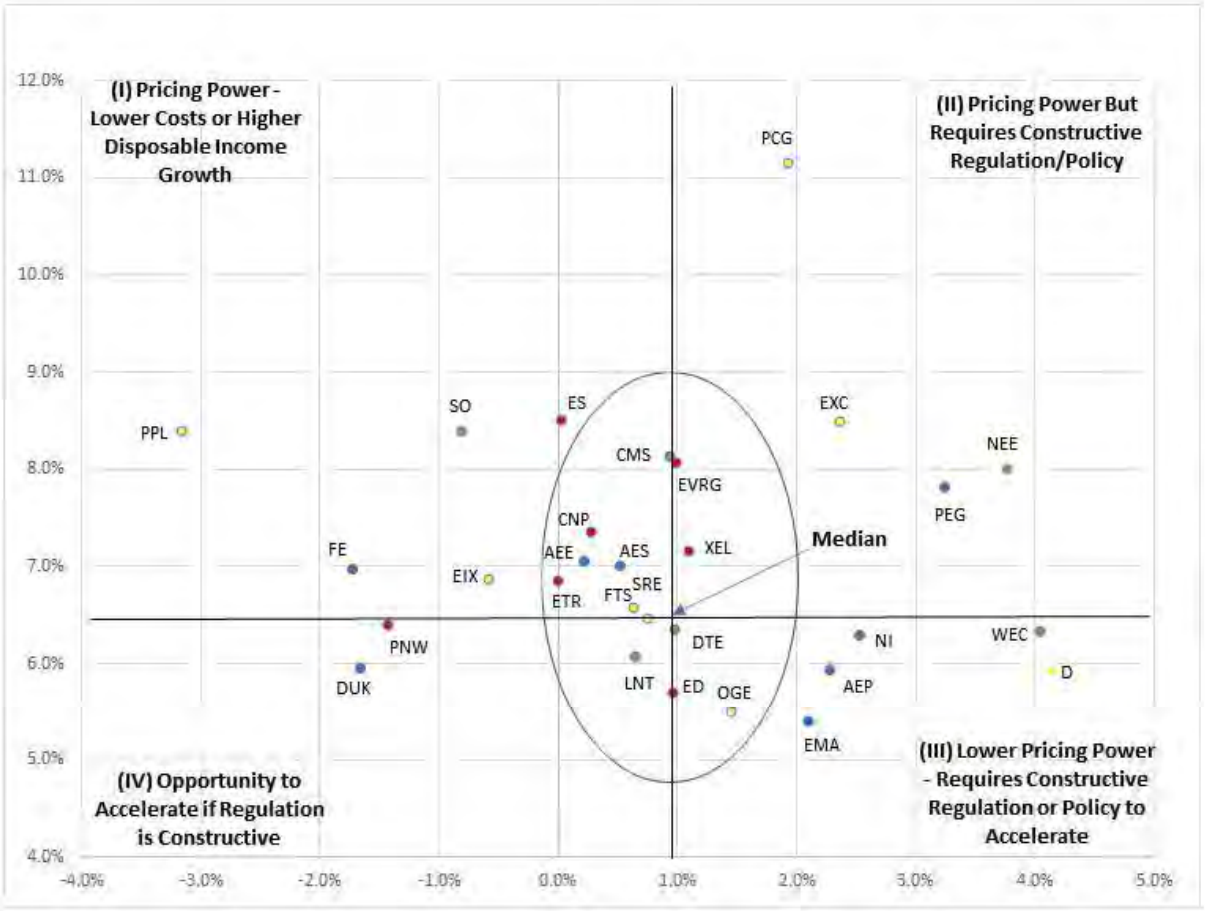
Source: Company filings, FactSet, S&P Global Market Intelligence, UBS Equity Research estimates

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.

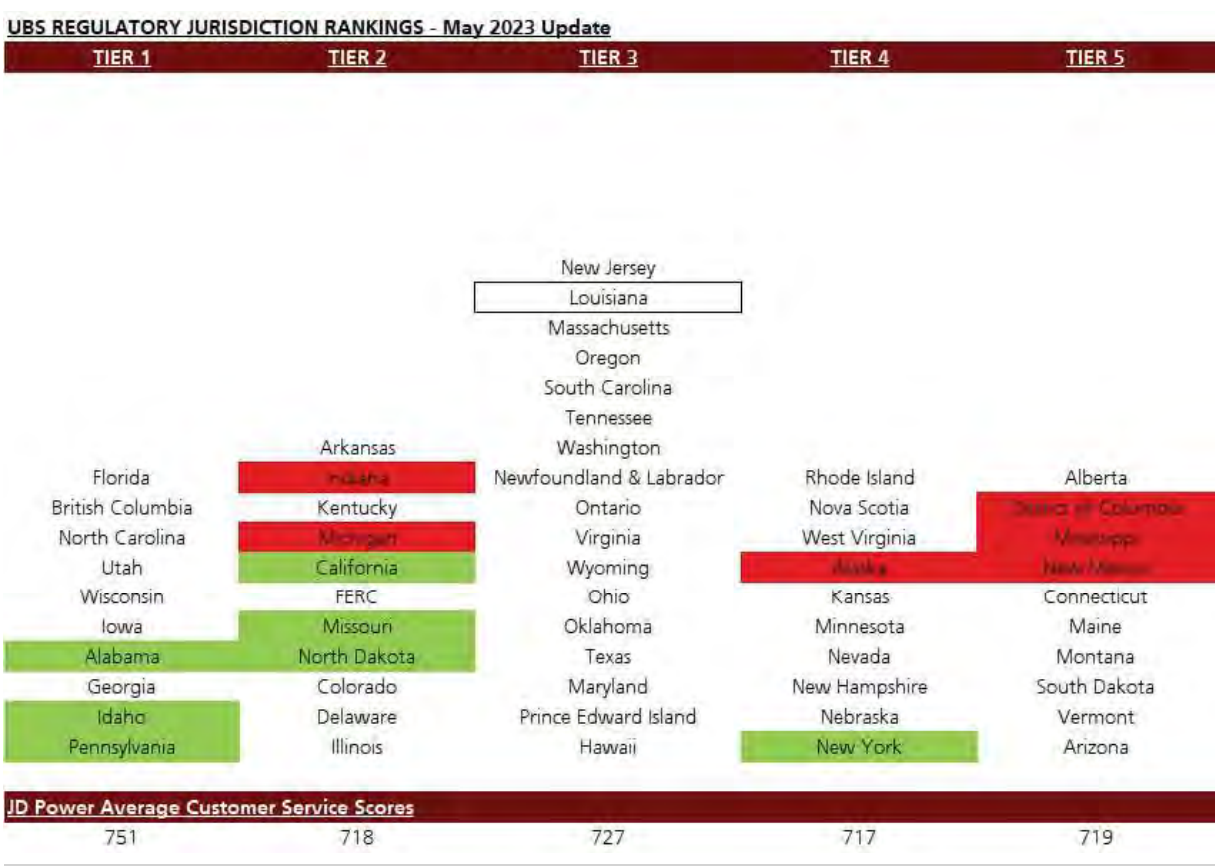
Bill inflation is calculated as the increase in annual bills/disposable income, annualized. Disposable income is grown at state forecast GDP, and a weighted average is taken by company.

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



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.
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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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Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens

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Sector	Utilities & Power, Oil & Gas, Infrastructure & Utilities, Utilities & Power, Midstream
Tags	Americas, Latin America, APAC, EMEA
Topic	Confronting Credit Headwinds , Seeking Energy & Climate Resilience , Outlook 2024

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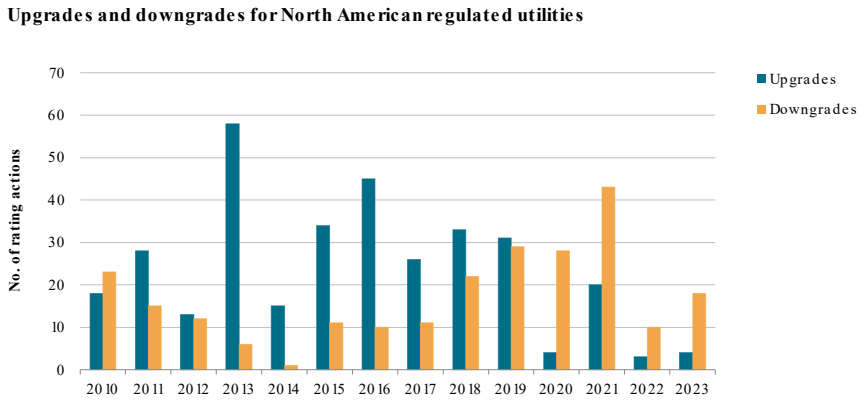
Key Takeaways

- We are updating our 2024 outlook on the investor-owned North American regulated utility industry to negative.
- Given the relatively high percentage of companies with negative outlooks, we expect that 2024 will likely be the fifth consecutive year that downgrades outpace upgrades.
- The industry faces rising physical risks and high cash flow deficits that may not be sufficiently funded in a credit-supportive manner.
- Still, we expect that the utility industry will maintain a median investment-grade rating of 'BBB+'.
- We also expect that a smaller percentage of companies rated 'BBB' or lower are more likely to implement measures to maintain or even improve credit quality.

Credit quality for North American investor-owned regulated utilities has weakened over the past four years, with downgrades outpacing upgrades by more than three times. We expect downgrades to again surpass upgrades in 2024 for the fifth consecutive year. In the decade prior to 2020, upgrades generally outpaced downgrades in the industry.

Chart 1



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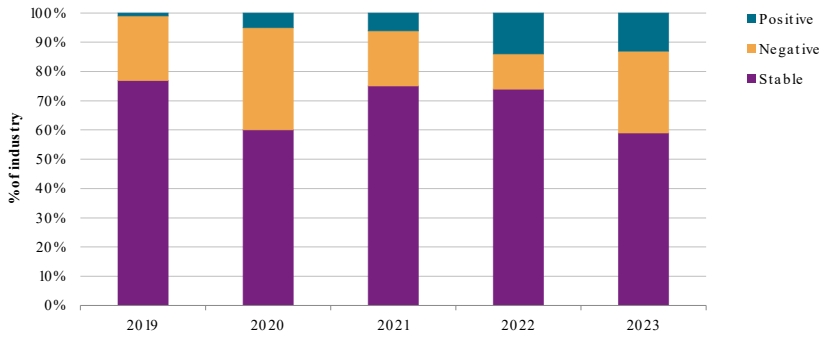
High Percentage Of Negative Outlooks

Currently, about 28% of the industry has a negative outlook or is listed on CreditWatch with negative implications. This is now the third time in the past five years that the year-end percentage of negative outlooks and CreditWatch listings has exceeded 20%. Given the current high percentage of negative outlooks it is increasingly likely that credit quality will again weaken in 2024.

Chart 2

Outlooks for the North American regulated utilities industry
At year end.



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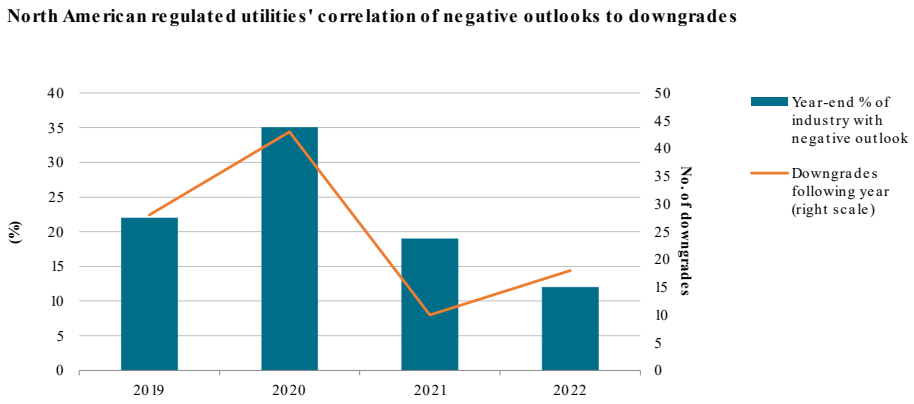
Future rating actions are typically correlated with our outlooks. The industry's share of negative outlooks reached a record high of 35% at year-end 2020, and the following year saw a record 43 downgrades. The industry's current percentage of negative outlooks is significantly larger than it was at year-ends 2021 and 2022, when downgrades still materially outpaced upgrades the following year. As such, given the current high percentage of negative outlooks, we anticipate that 2024 will be another challenging year for the industry's credit quality.

Chart 3



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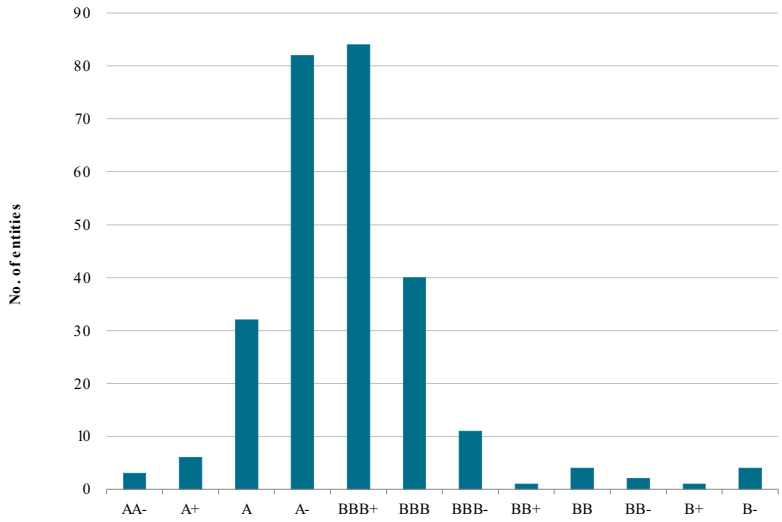
Median Credit Rating To Remain Investment Grade

The median rating among North American investor-owned regulated utilities is 'BBB+'. Despite our expectations for downgrades to again outpace upgrades in 2024, we expect that the median rating will remain 'BBB+'. To weaken the median rating to 'BBB', the industry would need about 70 downgrades to 'BBB' from the 'BBB+' level or above. This degree of credit weakening is well above our base-case expectations for 2024. However, this magnitude of weakening could occur over the next three years if this negative pace persists.

Chart 4

North American regulated utilities ratings distribution
As of Feb. 1, 2024.



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Headwinds To Credit Quality

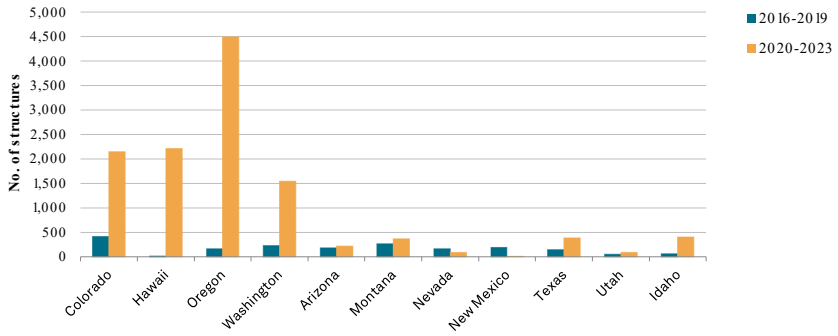
The industrywide negative outlook reflects rising physical risks as well as financial measures, which are weakening due to rising capital spending and cash flow deficits that are not funded in a sufficiently credit supportive manner. Furthermore, much of the industry operates with minimal financial cushion from their downgrade threshold. This increases the susceptibility to a downgrade if negative events occur beyond our base case.

Increase in physical risk

Climate change and an increase in wildfire risks are threatening credit quality. Wildfire risk was generally limited to California utilities just five years ago but has spread over the past several years.

Chart 5

Structures destroyed by wildfires in Western U.S. states
Excludes California



Sources: Headwaters Economics; National Fire and Aviation Management (FAMWeb).
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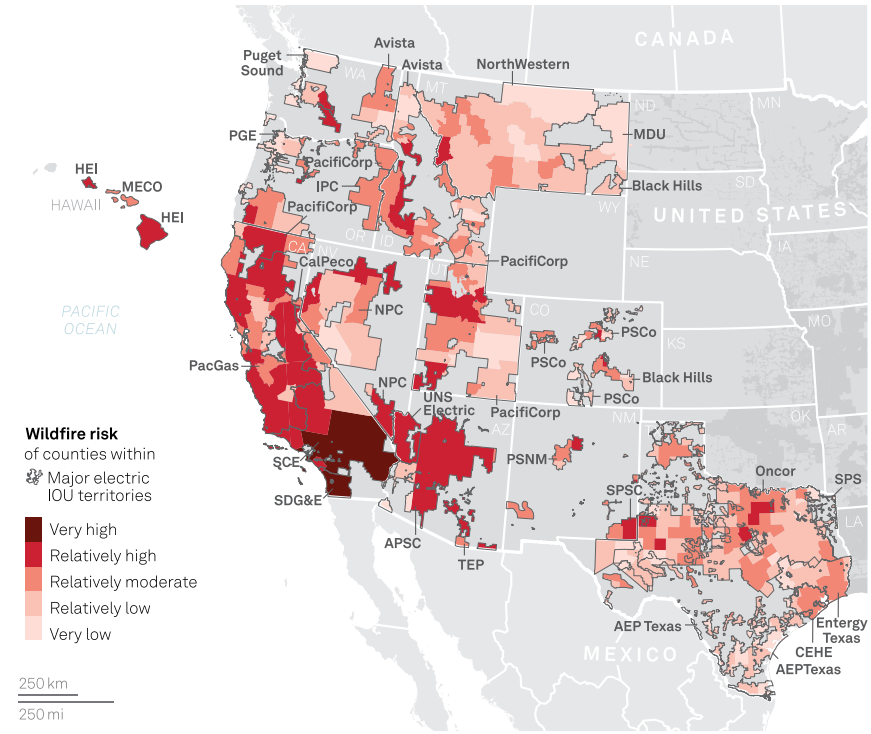
Since 2020, the number of structures destroyed by wildfires in Colorado, Hawaii, Idaho, Oregon, Washington, and Texas have all increased by more than 100% compared to 2016-2019. Meanwhile, Arizona, Montana, and Utah have each experienced increases of at least 20% over the same timeframe. Additionally, areas designated as high fire risk continue to increase across the Western U.S. due to climate change. To reduce these risks, many utilities are actively implementing mitigation plans designed to reduce wildfire exposure and litigation risks.

Wildfire risk across West Coast electricity territories



Source: FEMA, S&P Global Market Intelligence.
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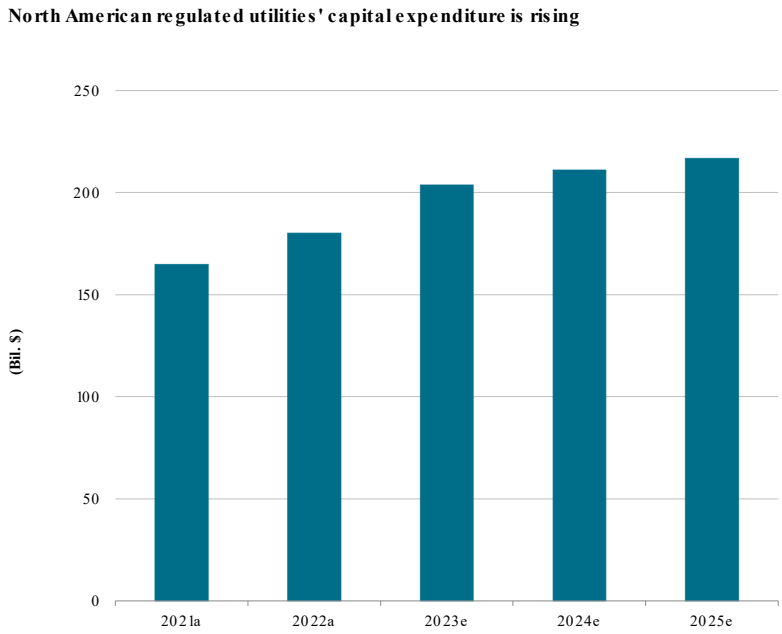
Increase in capital expenditure and cash flow deficits

The industry's capital spending remains at record levels, supporting initiatives for safety, reliability, energy transition, and growth. We consider these trends long term and expect that capital spending will only continue to increase over this decade.

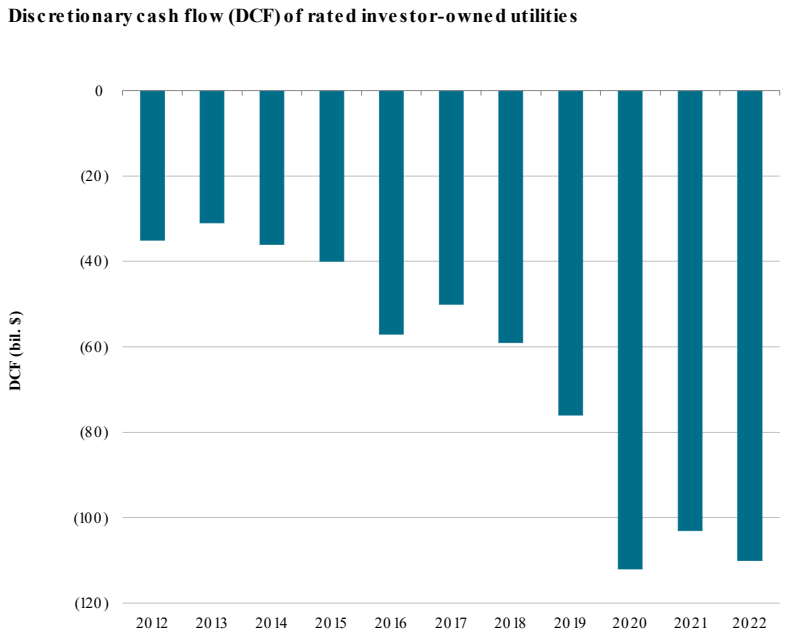
Chart 6



a--Actual. e--Estimate. Source: S&P Global Ratings.

Accordingly, cash flow deficits have increased, pressuring the industry's credit quality. For 2024, our base case assumes that the industry will fund its approximate $85 billion of cash flow deficits with about $40 billion in asset sales and equity issuance.

Chart 7



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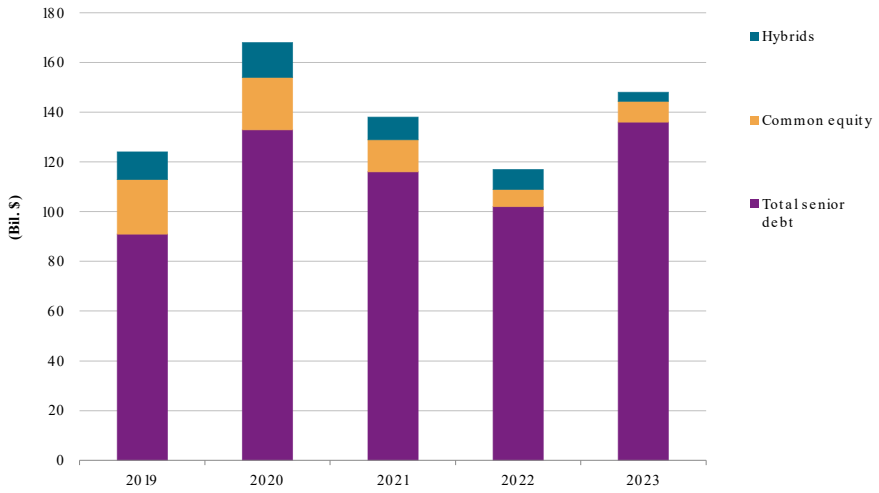
For 2023, the industry's actual equity issuance was considerably below our expectations, resulting in a weakening of financial performance and credit quality. If this trend persists, credit quality will again likely experience pressure in 2024.

Chart 8

Capital market issuance for North American regulated utilities



Senior debt includes first-mortgage bonds and senior unsecured. Hybrids includes junior subordinated debt, preferreds, subordinated debt, and equity units. Source: S&P Global Ratings, S&P Market Intelligence.
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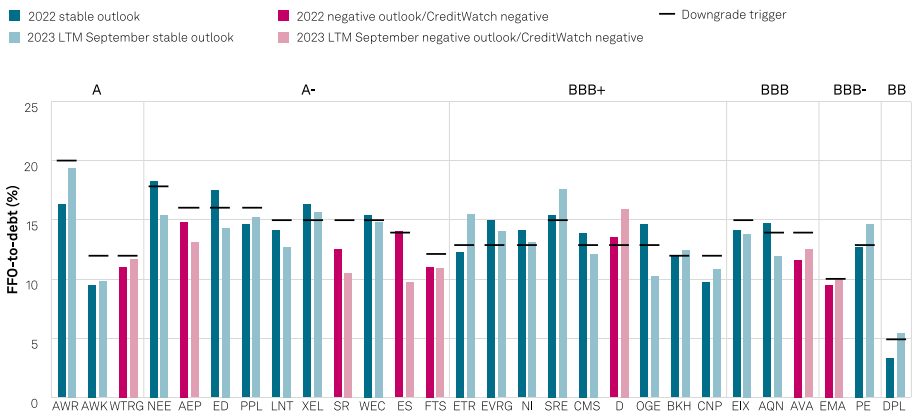
Strained financial cushion

About 35% of the industry is sustaining performance with minimal financial cushion, reflecting funds from operations (FFO) to debt that is less than 100 basis points (bps) above their downgrade threshold. The limited financial cushion affects a company's ability to absorb unexpected events beyond the base case for our ratings, increasing its susceptibility to a downgrade. Such unexpected events include higher interest rates, changes to inflation, delays to offshore wind projects, and rising taxes.

North American regulated utilities with minimal financial cushion



Data as of Feb. 6, 2024. FFO--Funds from operations. LTM—Last 12 months. AWR--American States Water Co. AWK--American Water Works Co. Inc. WTRG--Essential Utilities Inc. NEE--NextEra Energy Inc. AEP--American Electric Power Co. Inc. ED—Consolidated Edison Inc. PPL--PPL Corp. LNT--Alliant Energy Corp. XEL--Xcel Energy Inc. SR—Spire Inc. WEC--WEC Energy Group Inc. ES--Eversource Energy. FTS—Fortis Inc. ETR—Entergy Corp. EVRG--Evergy Inc. NI--NiSource Inc. SRE--Sempra. CMS—CMS Energy Corp. D--Dominion Energy Inc. OGE—OGE Energy Corp. BKH—Black Hills Corp. CNP--CenterPoint Energy Inc. EIX--Edison International. AQN—Algonquin Power & Utilities Corp. AVA--Avista Corp. EMA--Emera Inc. PE--Puget Energy Inc. DPL—DPL Inc.
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Upcoming debt maturities amid higher interest rates

The industry has considerable near-term debt maturities that must be refinanced, as well as rising discretionary cash flow deficits that are mostly funded with debt. Because of the regulatory lag, which is the timing difference between when a utility incurs costs and when it's recovered from ratepayers, rising interest rates weaken financial performance. S&P Global economists expect the federal funds rate will stabilize in 2024 and then begin to modestly decrease. Accordingly, as interest rates stabilize, it will ease pressure on the industry's financial performance.

Additionally, the spread between the 10-year treasury and the average authorized return on equity (ROE) has narrowed. Over the past three years, the 10-year treasury has increased by about 250 bps to about 4.0% from about 1.5% at year-end 2020. At the same time, average authorized ROE has essentially remained flat at about 9.5%. The narrowing of this spread directly hinders the industry's financial performance.

Elevated inflation rates

Although the rate of inflation has slowed from 2022 levels, it remains elevated relative to historical levels. We anticipate this will result in higher operations and maintenance (O&M) costs that could weaken financial performance. While some utilities have interim mechanisms that reduce the regulatory lag, most will have to file rate cases on a more frequent basis if inflation remains higher over the longer term.

Delayed renewable energy projects

Recently, several large offshore wind projects were delayed or canceled because of rising costs for these more challenging projects. For example, we recently placed Eversource Energy's ratings on CreditWatch with negative implications directly related to its share of higher costs associated with its offshore wind projects.

Alternative minimum tax (AMT)

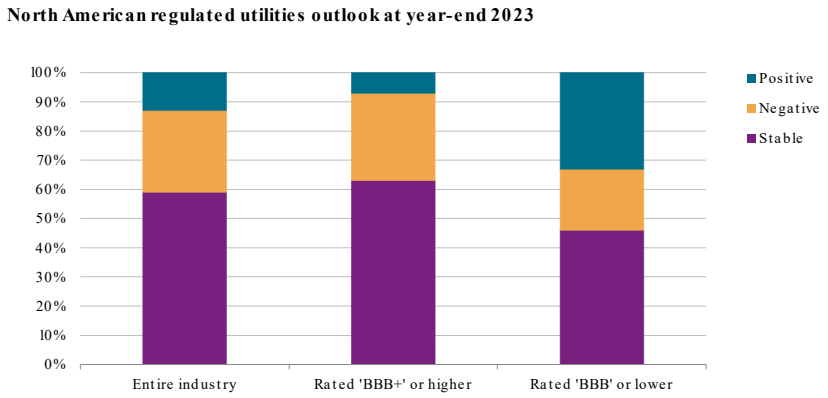
The Inflation Reduction Act of 2022 includes a 15% corporate AMT that we expect will weaken the financial measures of only about 10% of the industry. This is because the ATM is applicable to corporations with at least $1 billion of income that also do not have sufficient offsetting tax credits. Accordingly, we expect that most fully integrated large utilities with a growing or significant renewable generation portfolio will use their renewable tax credits to minimize or eliminate the AMT. However, the AMT could weaken financial measures of large electric transmission and distribution utilities, large natural gas local distribution companies, and large water utilities.

Lower-Rated Companies Will Likely Protect Credit Quality

We expect a majority of the industry's future downgrades will come from companies that are currently rated 'BBB+' or higher, as about 30% of companies in this category have a negative outlook. Overall, these higher-rated companies account for about 75% of the industry's portfolio. Conversely, we expect companies rated 'BBB' or lower will likely take measures to support or improve credit quality. This reflects the more than 30% of companies in this category that have a positive outlook.

Consequently, there is a broad industry trend that is bifurcating higher-rated and lower-rated companies that will likely result in weakening credit quality for the higher-rated companies and stable to improving credit quality for the smaller percentage of lower-rated companies. We believe this trend is consistent with the industry's current economic conditions of robust growth, cash flow deficits, and higher interest rates. Some higher-rated companies are determining that, under current conditions, they have excess credit capacity while lower-rated companies believe it is most optimal for them to operate at a higher rating.

Chart 9



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This report does not constitute a rating action.

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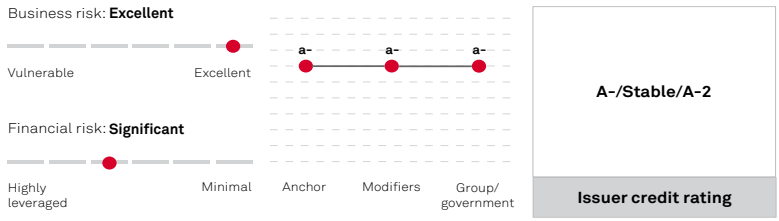
Consumers Energy Co.

August 20, 2024

Ratings Score Snapshot



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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.	Energy transition risks due to its dependence on natural gas and coal-fired generation (about 75% of electricity generated or purchased in 2023), partially mitigated by a plan to retire coal in 2025.
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 storms and convective storms.
	Exposure to cyclical commercial and industrial customers, which account for about 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 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 in the middle of an electric rate case and just received a settlement approval in its recent gas rate case. The company filed for a $325 million electric rate increase based on a 10.25% ROE in May and reached a settlement with various intervenors and received an order from the Michigan Public Service Commission (MPSC) for a $35 million gas rate increase based on a 9.90% ROE. The gas rate increase granted was about only a quarter of the rate increase requested. However, this difference was partially because the commission authorized bill credits of $27.5 million per year over four years related to the gain on the sale of CE's appliance service plan business, which happened after and was not a part of the company's case filing.

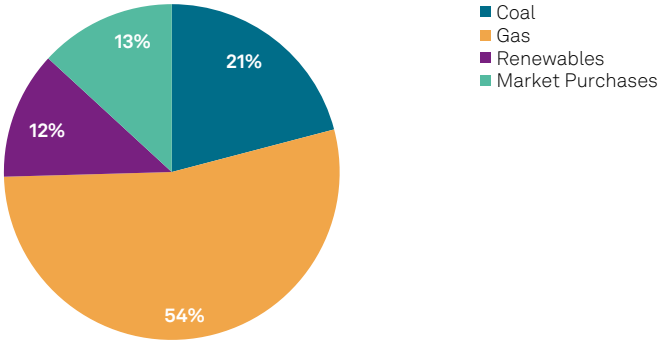
Consumers Energy Co. rate case details

	Electric rate case		Gas rate case	
	Present case: requested by company 5/31/2024	Previous case: authorized by MPSC 3/1/2024	Authorized by MPSC 7/23/2024	Requested by company 12/15/2023
Rate change amount (mil. $)	325	92.0	35.0	136.0
Rate base (mil. $)	15,571.5	13,669	10,850*	10,970
Rate base valuation method	Average	Average	Average	Average
Return on equity (%)	10.25	9.90	9.90	10.25
Common equity to total capital (%)	42.36	41.13	41.48*	42.73
Rate of return (%)	6.21	5.86	5.93*	6.20
Rate case test year end date	2/28/2026	2/28/2025	9/30/2025	9/30/2025

*Company assumption under settlement. Source: S&P CapitalIQ Pro. MPSC--Michigan Public Service Commission.

The company's elevated capital spending plan prioritizes infrastructure upgrades, and its energy transition plans. Over the next five years, CE plans to spend about $17 billion to maintain and upgrade its gas infrastructure and electric distribution systems and reduce its carbon emissions. The capital plan includes investment of about $6.3 billion in the gas segment and about $10.7 billion in electric (of which, about two thirds are dedicated to distribution-related spending). 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. Furthermore, the company's IRP targets a gradual reduction in its gas-fired generation dependence after 2025, as well as meeting 90% of its customer needs with clean energy sources by 2040. The company also announced a net-zero greenhouse gas emissions target by 2050 and a zero methane emissions target by 2030 for its gas distribution system.

CE's 2023 generated and purchased electricity supply by source



Source: Company filings.

The company's credit metrics were weak in 2023, largely because of weather-related issues. Mild weather impaired sales for the company's gas operations, and the company saw heightened winter and convective storm activities. While the company has effectively recovered storm costs in past rate case proceedings, it has not been able to defer storm costs into regulatory assets, which introduced regulatory lag.

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 about 10,000-15,000 people, 7,000-9,000 housing units, of which about 40%-60% are occupied, and median home values if $100,000-$150,000 according to 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 such 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%-19%.

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%-19%.

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 $2.8 billion-$3.0 billion annually;
- Annual dividends averaging about $1 billion-$1.1 billion annually;
- All debt maturities refinanced; and
- Continued negative discretionary cash flow financed in a balanced manner to support the regulated capital structure.

Key metrics

Consumers Energy Co.--Forecast summary

Period ending	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. $)	2020a	2021a	2022a	2023a	2024e	2025f	2026f	2027f
Revenue	6,155	6,987	8,117	7,129	8,230	8,803	9,333	9,879
EBITDA (reported)	2,244	2,252	2,321	2,405	2,795	3,081	3,337	3,582
Plus: Operating lease adjustment (OLA) rent	9	8	6	6	6	6	6	6
Plus/(less): Other	139	146	70	74	(39)	(40)	(40)	(22)
EBITDA	2,392	2,406	2,397	2,485	2,762	3,047	3,303	3,566
Less: Cash interest paid	(373)	(376)	(343)	(454)	(480)	(559)	(620)	(684)
Less: Cash taxes paid	(51)	10	2	(31)	(112)	3	1	(9)
Plus/(less): Other	--	--	--	--	--	--	--	--
Funds from operations (FFO)	1,968	2,040	2,057	2,000	2,169	2,491	2,685	2,873
EBIT	1,268	1,246	1,262	1,349	1,625	1,826	1,993	2,172
Interest expense	393	381	375	496	512	591	652	716
Cash flow from operations (CFO)	1,265	2,013	984	2,415	2,316	2,529	2,662	2,802
Capital expenditure (capex)	2,254	2,136	2,275	2,279	2,892	3,318	2,897	2,890
Free operating cash flow (FOCF)	(989)	(124)	(1,291)	136	(576)	(789)	(235)	(88)
Dividends	639	723	770	696	865	951	1,047	1,129
Share repurchases (reported)	--	--	--	--	--	--	--	--
Discretionary cash flow (DCF)	(1,628)	(847)	(2,061)	(560)	(1,441)	(1,740)	(1,282)	(1,217)
Debt (reported)	8,429	8,810	10,287	11,285	12,331	13,437	14,319	15,172

Consumers Energy Co.--Forecast summary

Plus: Lease liabilities debt	88	74	81	41	26	19	15	12
Plus: Pension and other postretirement debt	--	--	--	--	--	--	--	--
Less: Accessible cash and liquid Investments	(20)	(22)	(43)	(35)	(100)	(100)	(100)	(100)
Plus/(less): Other	616	553	699	80	167	282	404	532
Debt	9,113	9,415	11,024	11,371	12,423	13,637	14,638	15,616
Equity	8,556	9,261	10,137	10,782	11,564	12,735	13,667	14,580
Adjusted ratios								
Debt/EBITDA (x)	3.8	3.9	4.6	4.6	4.5	4.5	4.4	4.4
FFO/debt (%)	21.6	21.7	18.7	17.6	17.5	18.3	18.3	18.4
FFO cash interest coverage (x)	6.3	6.4	7.0	5.4	5.5	5.5	5.3	5.2
EBITDA interest coverage (x)	6.1	6.3	6.4	5.0	5.4	5.2	5.1	5.0
CFO/debt (%)	13.9	21.4	8.9	21.2	18.6	18.5	18.2	17.9
FOCF/debt (%)	(10.9)	(1.3)	(11.7)	1.2	(4.6)	(5.8)	(1.6)	(0.6)
DCF/debt (%)	(17.9)	(9.0)	(18.7)	(4.9)	(11.6)	(12.8)	(8.8)	(7.8)
Annual revenue growth (%)	(2.9)	13.5	16.2	(12.2)	15.4	7.0	6.0	5.9
EBITDA margin (%)	38.9	34.4	29.5	34.9	33.6	34.6	35.4	36.1
Return on capital (%)	7.5	6.9	6.3	6.2	7.0	7.3	7.3	7.4
Debt/debt and equity (%)	51.6	50.4	52.1	51.3	51.8	51.7	51.7	51.7
Debt fixed-charge coverage (x)	6.1	6.3	6.4	5.0	5.4	5.2	5.1	5.0

All figures are adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. $--U.S. dollar.

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 million customers in Michigan. CE's electric business operates as a vertically integrated utility that generates, distributes, and sells electricity. The electric utility sources about 40%-50% 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.

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/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2023-12-31	2023-12-31	2023-12-31	2023-12-31	2023-12-31

Consumers Energy Co.

Consumers Energy Co.--Peer Comparisons

Mil.	$	$	$	$	$
Revenue	7,129	5,729	1,827	4,045	13,476
EBITDA	2,485	2,715	760	1,716	4,232
Funds from operations (FFO)	2,000	2,282	544	1,056	3,276
Interest	496	623	152	383	1,032
Cash interest paid	454	418	166	561	983
Operating cash flow (OCF)	2,415	1,534	558	1,028	2,250
Capital expenditure	2,279	3,076	999	1,183	4,010
Free operating cash flow (FOCF)	136	(1,542)	(441)	(155)	(1,760)
Discretionary cash flow (DCF)	(560)	(2,544)	(625)	(524)	(2,816)
Cash and short-term investments	35	15	7	6	1,138
Gross available cash	35	15	7	6	1,138
Debt	11,371	12,009	3,748	5,657	22,824
Equity	10,782	10,224	3,897	5,068	19,146
EBITDA margin (%)	34.9	47.4	41.6	42.4	31.4
Return on capital (%)	6.2	6.8	7.6	12.2	5.6
EBITDA interest coverage (x)	5.0	4.4	5.0	4.5	4.1
FFO cash interest coverage (x)	5.4	6.5	4.3	2.9	4.3
Debt/EBITDA (x)	4.6	4.4	4.9	3.3	5.4
FFO/debt (%)	17.6	19.0	14.5	18.7	14.4
OCF/debt (%)	21.2	12.8	14.9	18.2	9.9
FOCF/debt (%)	1.2	(12.8)	(11.8)	(2.7)	(7.7)
DCF/debt (%)	(4.9)	(21.2)	(16.7)	(9.3)	(12.3)

Business Risk

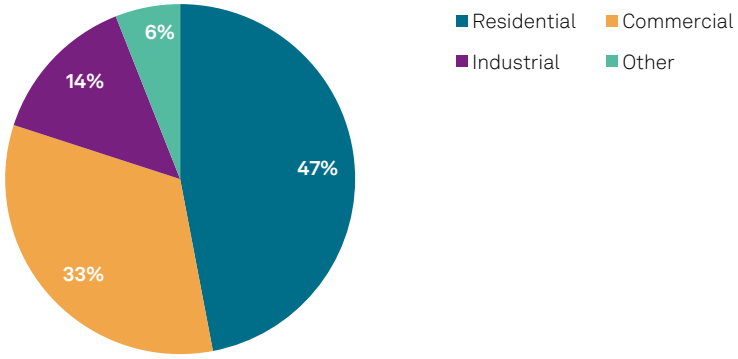
Our assessment of CE's business risk profile reflects the company's monopolistic electric and natural gas utility operations and effective management of regulatory risk. The MPSC regulates CE, and we view the regulatory environment in Michigan as above average compared with peers. This is demonstrated 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 also 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 the effects of price volatility and to support its gas system operations by injecting natural gas into storage during the summer months for use during the winter months. During 2023, 45% of the natural gas supplied to all customers during the winter months came from storage. Additionally, CE's large customer base

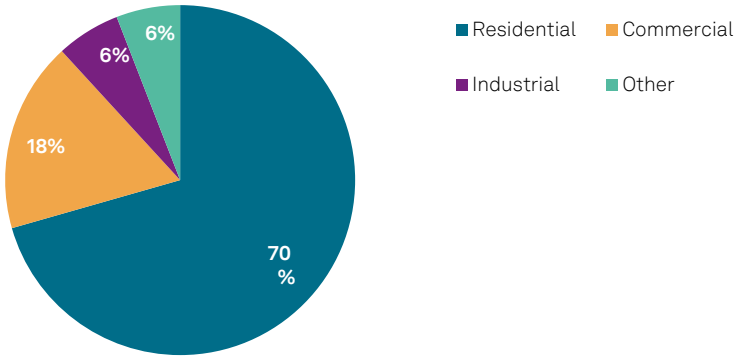
of about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan bolsters the company's business risk profile. This said, the company is exposed to cyclical commercial and industrial customers for its electric operations, which contribute about 45%-50% of the company's electric revenues.

CE's 2023 electrical revenue by customer class



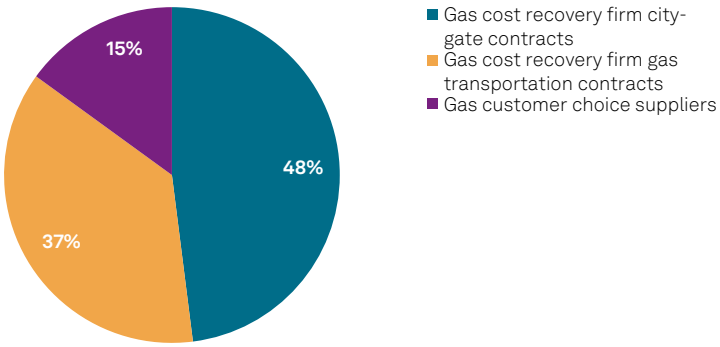
Source: Company filings.

CE's 2023 gas revenue by customer class



Source: Company filings

CE's 2023 gas supply sources



Source: Company filings

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:

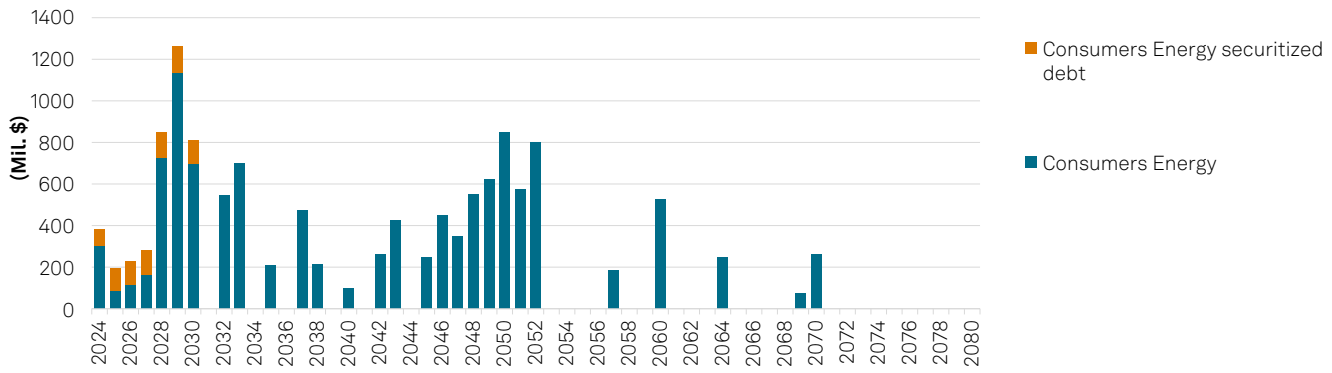
- Elevated capital spending averaging $2.8 billion-$3.0 billion annually over the forecast period;
- Dividends averaging $1 billion-$1.1 billion annually;
- Equity injections by the parent to maintain the company's capital structure;
- Continued use of existing regulatory mechanisms;
- Negative discretionary 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%-19%.

Consumers Energy Co.

Debt maturities

Consumers Energy debt maturities



Source: Company filings and S&P Global Ratings.

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Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,430	6,341	6,155	6,987	8,117	7,129
EBITDA	2,152	2,252	2,392	2,406	2,397	2,485
Funds from operations (FFO)	1,665	1,823	1,968	2,040	2,057	2,000
Interest expense	355	335	393	381	375	496
Cash interest paid	331	296	373	376	343	454
Operating cash flow (OCF)	1,533	1,688	1,265	2,013	984	2,415
Capital expenditure	1,920	2,191	2,254	2,136	2,275	2,279
Free operating cash flow (FOCF)	(387)	(502)	(989)	(124)	(1,291)	136
Discretionary cash flow (DCF)	(918)	(1,094)	(1,628)	(847)	(2,061)	(560)
Cash and short-term investments	39	11	20	22	43	35
Gross available cash	39	11	20	22	43	35
Debt	7,774	8,238	9,113	9,415	11,024	11,371
Common equity	6,920	7,737	8,556	9,261	10,137	10,782
Adjusted ratios						
EBITDA margin (%)	33.5	35.5	38.9	34.4	29.5	34.9
Return on capital (%)	7.9	7.7	7.5	6.9	6.3	6.2
EBITDA interest coverage (x)	6.1	6.7	6.1	6.3	6.4	5.0
FFO cash interest coverage (x)	6.0	7.2	6.3	6.4	7.0	5.4
Debt/EBITDA (x)	3.6	3.7	3.8	3.9	4.6	4.6
FFO/debt (%)	21.4	22.1	21.6	21.7	18.7	17.6
OCF/debt (%)	19.7	20.5	13.9	21.4	8.9	21.2

Consumers Energy Co.

Consumers Energy Co.--Financial Summary

FOCF/debt (%)	(5.0)	(6.1)	(10.9)	(1.3)	(11.7)	1.2
DCF/debt (%)	(11.8)	(13.3)	(17.9)	(9.0)	(18.7)	(4.9)

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-31-2023									
Company reported amounts	11,285	10,800	7,166	2,405	1,268	448	2,485	2,430	697	2,248
Cash taxes paid	-	-	-	-	-	-	(31)	-	-	-
Cash interest paid	-	-	-	-	-	-	(438)	-	-	-
Lease liabilities	41	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	6	1	1	(1)	5	-	-
Intermediate hybrids (equity)	19	(19)	-	-	-	1	(1)	(1)	(1)	-
Accessible cash and liquid investments	(35)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	3	(3)	(3)	-	(3)
Share-based compensation expense	-	-	-	26	-	-	-	-	-	-
Securitized stranded costs	(787)	-	(37)	(37)	(8)	(8)	8	(29)	-	-
Power purchase agreements	358	-	-	53	19	19	(19)	34	-	34
Asset-retirement obligations	584	-	-	32	32	32	-	-	-	-
Nonoperating income (expense)	-	-	-	-	37	-	-	-	-	-
Reclassification of interest and dividend cash flows	-	-	-	-	-	-	-	(21)	-	-
Debt: other	(93)	-	-	-	-	-	-	-	-	-
Total adjustments	86	(19)	(37)	80	81	48	(485)	(15)	(1)	31
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	11,371	10,782	7,129	2,485	1,349	496	2,000	2,415	696	2,279

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, another $250 million in committed credit facilities through November 2025, 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 the parent CMS Energy as per its renewed credit agreement in December 2023.

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. The company has around $200 million of long-term debt maturities in 2025, and we expect the company to proactively address these maturities well in advance of their scheduled due dates.

Principal liquidity sources

- Cash FFO of about $2.4 billion;
- Credit facilities of about $1.3 billion;
- Working capital inflows of about $70 million; and
- Available cash of about $1.3 billion following the company's recent debt issuance.

Principal liquidity uses

- Debt maturities of about $772 million over the next 12 months;
- Estimated maintenance capital spending of about $2.7 billion; and
- Dividends of about $900 million.

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. Its generation portfolio's capacity comprises about 36% natural gas, 20% coal, 17%

hydroelectric, 17% oil and gas, and 9% wind and solar as of Dec. 31, 2023. The company's accelerated coal retirement plan for its utility slightly mitigates this risk. It includes a goal to be coal-free in 2025 and have 90% of its utility's capacity portfolio sourced from clean energy resources by 2040.

Furthermore, the company has experienced heightened winter and convective storm activities in recent years. While the company has effectively recovered storm costs in past rate case proceedings, it has not been able to defer storm costs into regulatory assets, which could introduce regulatory lag especially if costs are outsized.

While CMS has not been found culpable for any wildfires in its service territory and is not currently party to any 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 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

CE's capital structure consists of about $12.5 billion of long-term debt, including about $11.7 billion in first-mortgage bonds (FMBs), $787 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-
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	Insulated (no impact on SACP)

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- 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: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- 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
- 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
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of August 20, 2024)*

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

Consumers Energy Co.

Ratings Detail (as of August 20, 2024)*

*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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MOODY'S RATINGS

Infrastructure And Project Finance

CREDIT OPINION
31 May 2024

Update

Send Your Feedback

RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	(P)A3
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

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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EMEA	44-20-7772-5454

Consumers Energy Company

Update to credit analysis

Summary

Consumers Energy Company's (Consumers Energy) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in the credit supportive regulatory environment of Michigan. We expect the utility to maintain a stable financial profile with cash flow from operations before changes in working capital (CFO pre-WC) to debt averaging around 20-21%, including an adjustment to exclude securitization debt, over the next 2-3 years. At the end of the latest twelve month (LTM) period ending 31 March 2024, Consumers Energy's CFO pre-WC to debt ratio was 20%, including the adjustment to exclude securitization bonds. The company will continue to execute its robust capital investment plan and have an active regulatory calendar over this period. Based on the Michigan regulatory framework, we expect the utility to recover its investment costs on a timely basis and to earn an appropriate return on its investments.

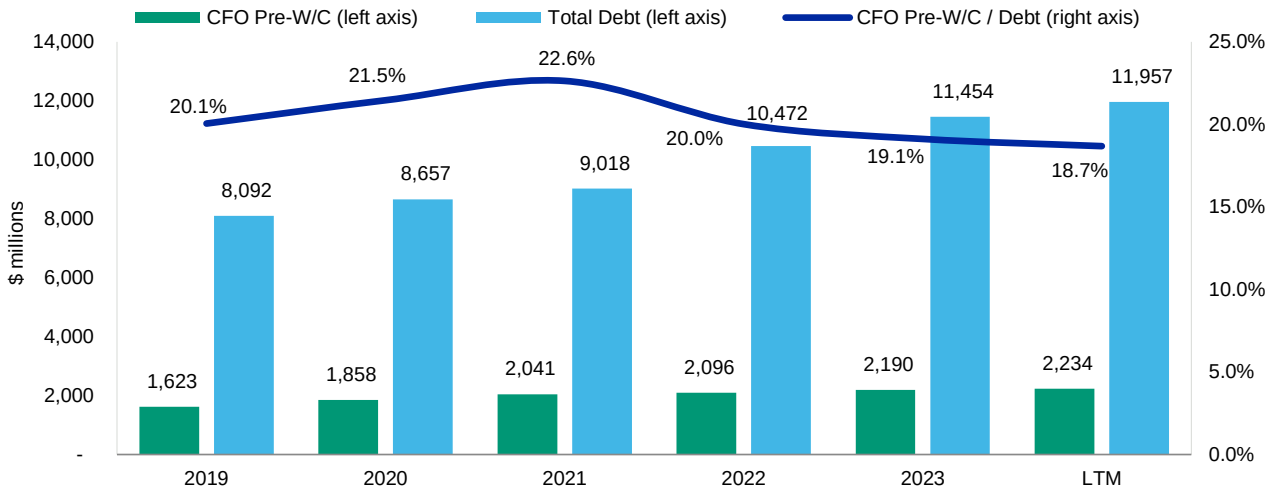
Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). However, CMS has made notable progress in reducing the percentage of parent debt in its capital structure in recent years. We now estimate that the percentage of parent debt will remain below 25% of total consolidated debt. All of Consumer Energy's outstanding debt obligations are secured.

Recent development

In November 2023, Michigan enacted a new energy law (2023 Energy Law), which raised the state's renewable energy standard while providing additional authority to the Michigan Public Service Commission (MPSC). Consumer Energy's operations are under the purview of MPSC. In general, we view this development to be constructive because the utilities in the state will now outline a renewable energy plan with greater transparency, and the MPSC will have an expanded scope of consideration for various factors influencing Consumers Energy' plan to decarbonize.

Exhibit 1

Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.3%, 20.4% and 20.0% in 2022, 2023 and LTM ending 31 March 2024, respectively.

Source: Moody's Financial Metrics

Credit strengths

» Credit supportive regulatory environment in Michigan

» Transparent and timely cost recovery

» Stable financial profile

Credit challenges

» Robust capital investment plan

» Maintaining regulatory support for these capital investments

» Lack of geographic and regulatory diversity with single state service territory

Rating outlook

The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. The stable outlook also incorporates our view that Consumers Energy will maintain prudent financial policies while managing through its robust investment cycle and that debt levels at the parent will not increase materially.

Factors that could lead to an upgrade

A rating upgrade could be considered if credit metrics improve such that CFO pre-WC to debt is above 21% on a sustained basis. In addition, if the Michigan regulatory framework becomes even more formulaic, transparent or timely with its suite of cost recovery mechanisms for Consumers Energy, a rating upgrade could be possible.

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 could be considered if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment; or if the CFO pre-WC to debt ratio declines below 18% on a sustained basis.

Key indicators

Exhibit 2

Consumers Energy Company

	2019	2020	2021	2022	2023	LTM
CFO Pre-W/C + Interest / Interest	6.2x	6.6x	7.5x	7.1x	5.8x	5.6x
CFO Pre-W/C / Debt	20.1%	21.5%	22.6%	20.0%	19.1%	18.7%
CFO Pre-W/C – Dividends / Debt	12.7%	14.1%	14.6%	12.7%	13.0%	13.0%
Debt / Capitalization	46.0%	44.9%	43.7%	45.1%	45.8%	46.7%

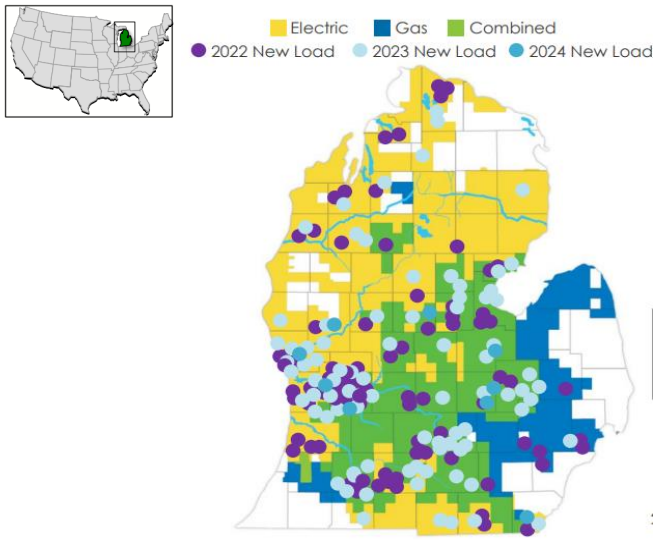
All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Credit metrics included in the exhibit include securitization bonds. When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.3%, 20.5% and 20.0% in 2022, 2023 and LTM ending 31 March 2024, 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 $25 billion in 2023. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. The utility is a wholly-owned subsidiary of CMS and, as the primary subsidiary of the parent company, it represents over 95% of CMS's consolidated earnings. In addition to Consumers Energy, CMS has a subsidiary called NorthStar Clean Energy, a non-utility domestic independent power producer and marketer.

Exhibit 3

Consumers Energy's Service Territory



Source: Company Presentations

Detailed credit considerations

Credit supportive regulatory environment

Consumers Energy is regulated by the MPSC, which has a regulatory framework that we view to be more credit supportive than most other states. 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.

In November 2023, new energy legislation (2023 Energy Law) was enacted. Under the new law, the state's 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. CMS's utility subsidiary Consumers Energy will file updates to its renewable energy plans in 2024 and its Clean Energy Plan in or before 2027. Given the existing regulatory framework in Michigan, we expect the company's collaborative dialogue with both stakeholders and regulator to continue under the new legislation.

In June 2022, Consumers Energy and key stakeholders in Michigan reached a settlement related to the company's latest IRP. The settlement included the retirement of all of its remaining coal power plants (all three units at the Campbell power plant site) in 2025 as a result of the 2021 IRP. Consumers Energy will be able to record approximately $1.3 billion of the remaining book value of these power plants 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 will minimize the impact of the accelerated coal retirements on Consumers Energy's credit metrics. We view this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

Timeliness of cost recovery based on a prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous formulaic rate adjustment mechanisms that provide a high degree of 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, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/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. Consumers Energy's RDM compares and adjusts for differences between weather normalized actual and authorized revenues. The company's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing less than 250 miles of cast iron pipe and other high-risk components.

Active rate case filing cadence

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. The utility currently has its gas rate case pending before the MPSC, and filed its request for an electric rate increase on 31 May 2024. Over the last three years, Consumers Energy experienced downward pressure on its allowed ROE in its rate cases although the company was able to maintain a 9.9% allowed ROE. We expect Consumers Energy to maintain a stable financial profile because there are other offsetting mechanisms such as usage of forward test year to allow the utility to earn appropriate returns and to recover investment costs on a timely basis. However, further deterioration of the allowed ROE is likely to put negative pressure on the company's overall financial profile.

On 1 March 2024, the commission authorized a $92 million increase based on a 9.9% ROE, 50.02%% equity capital structure and a $13.67 billion rate base value. Also, the final order approved an Investment Recovery Mechanism (IRM) rider for distribution reliability projects totaling $99 million over two years.

On 15 December 2023, the utility filed a gas rate case, seeking a $136 million increase based on a projected test year for the 12-month period ending 30 September 2025, requesting a 10.25% ROE, 51.5% equity capital structure and a rate base value estimated around $10.97 billion. In April 2024, the MPSC Staff recommended an $70.77 million increase based on a 9.85% ROE, 49.92% equity capital structure and a $10.88 billion rate base value. A final decision is expected by 15 October 2024.

Stable credit metrics expected to be maintained through its high capital investment cycle

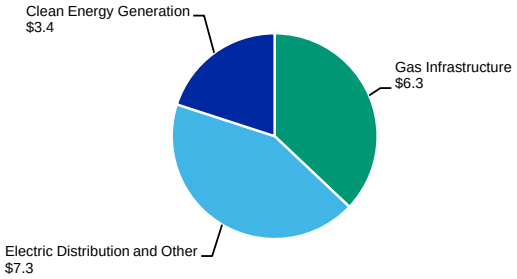
Consumers Energy's capital spending continues to be robust as it is currently in the midst of a large capital investment plan. The company increased its five-year capital expenditure plan through 2028 to $17 billion, approximately $1.5 billion higher than the previous plan. Consumers Energy will invest approximately $6.3 billion primarily to maintain and upgrade its gas utility infrastructure; $7.3 billion related to its electric distribution and other infrastructure; and $3.4 billion related to clean energy generation. These investments should enhance the company's reliability and safety as well as help it execute its decarbonization plan.

Exhibit 4
Consumers Energy's elevated capital program will extend at least through 2028
$ billions

Source: Company 10K

Through this period, Consumers Energy plans to keep rate increases modest, which should help to maintain regulatory support for investment cost recovery. 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 Consumers Energy to maintain its CFO pre-WC to debt at around 20%-21% on average over the next 2-3 years. At the end of 2023 and for the LTM period ending 31 March 2024, Consumers Energy produced a CFO pre-WC to debt ratio of 20.5% and 20%, respectively, excluding securitization debt.

Exhibit 5
Planned Capital Expenditures 2024 - 2028
$ billions



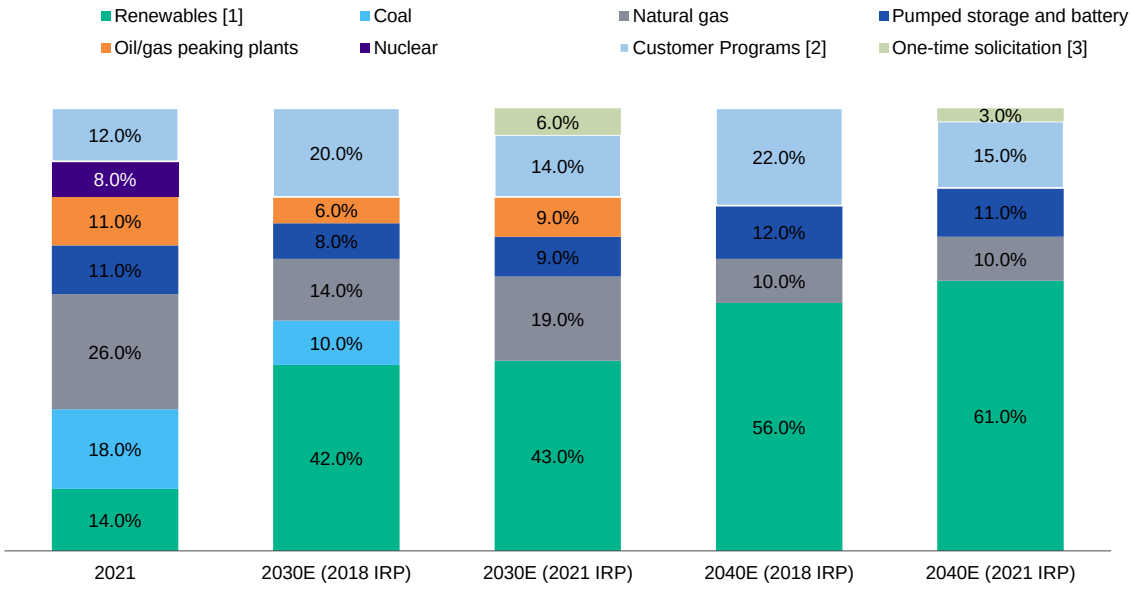
Source: Company 10K

Based on Consumers' latest IRP approved in 2022, the utility will add up to 8 GW of solar power, which is 2 GW more than what was approved in the company's 2018 IRP. As a result, by 2040, more than 60% of Consumers Energy's generation capacity will be from renewable sources. In order to replace the retiring coal capacity, the utility acquired the Covert natural gas-fired power plant for

approximately $815 million in 2023. It issued requests for proposals (RFP) for two purchased power agreements (PPA) for 500 MW of dispatchable generation and 200 MW of clean energy sources.

Exhibit 6

Based on the latest IRP settlement, more than 60% of Consumers Energy's generation sources will be renewables by 2040



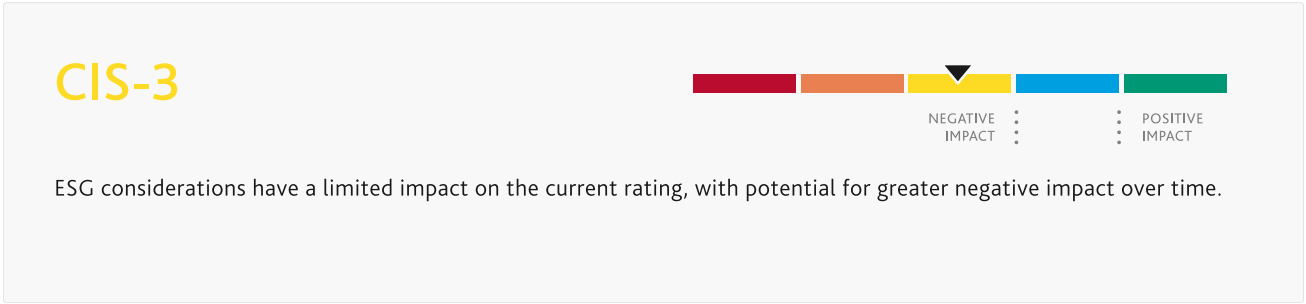
[1] Does not include renewable RECs.
[2] Includes energy waste reduction, demand response, and conservation voltage reduction program.
[3] One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.
Source: Company's 10-K in 2022 and 2021, and latest investor presentation

ESG considerations

Consumers Energy Company's ESG credit impact score is CIS-3

Exhibit 7

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 and moderating carbon transition risk. It also incorporates social risks stemming from inherent risk associated with regulated utilities and governance risk that is not a material driver.

Exhibit 8
ESG issuer profile scores

Source: Moody's Ratings

Environmental

Consumers Energy's **E-3** issuer profile score reflects its moderate position for the carbon transition with tangible strategies and plans in place that substantially mitigate its carbon transition exposure. The utility is currently in a transition to phase out its coal-fired generation and targets zero coal-fired generation output in 2025, accelerated from its prior target of 2039. The utility also established a goal of net zero methane emission for its gas delivery system by 2030; net zero carbon emissions for its electric business by 2040, including MISO market purchases and PPAs; and net zero greenhouse gas emissions for its entire business, including customer and supplier emissions, by 2050. Michigan's regulatory framework supports the utility's transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Social

S-3 issuer profile score for Consumers Energy 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 Michigan Public Service Commission, 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 and is not a material driver in the company's overall credit profile. It also incorporates its position as a subsidiary of CMS whose corporate governance considerations including financial policy and risk management influence Consumers Energy.

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 secured revolving credit facility expiring in December 2027 and, as of 31 March 2024, net availability was $1.073 billion with $27 million of letters of credit outstanding. Consumers Energy also maintains a $250 million secured credit facility terminating in November 2025 and had $197 million available as of 31 March 2024. Both facilities are secured by first mortgage bonds. 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 March 2024, 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 March 2024, debt to capital was 50%.

These facilities includes sustainability linked pricing metrics, which permits pricing adjustments for meeting targets related to sustainability. Targets include renewable generation and diverse supplier spend, highlighting its commitment to shifting its exposure to a greater renewable content and to supplier diversity.

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.

For the LTM period ended 31 March 2024, Consumers generated approximately $2.3 billion of cash from operations, invested $3.2 billion and distributed $673 million of dividends to CMS, resulting in negative free cash flow of approximately $1.6 billion. Given its robust investment plan, we expect Consumers Energy to maintain its negative free cash flow position over the 12-18 months.

In January 2024, Consumers Energy issued $600 million first mortgage bonds with 4.6% rate maturing in May 2029.

Rating methodology and scorecard factors

Exhibit 9

Methodology Scoring Factors

Consumers Energy Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2024		Moody's 12-18 Month Forward View As of 5/19/2024 [3]	
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)	6.5x	Aa	5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	20.4%	Baa	20% - 21%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	13.4%	Baa	13% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	44.5%	A	45% - 46%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A2		A3
b) Actual Rating Assigned				A3

* Senior Secured Rating.
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2024.
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 10

Cash Flow and Credit Metrics

CF Metrics (in $ millions)	2019	2020	2021	2022	2023	LTM
FFO	**1,752**	**1,994**	**2,054**	**2,125**	**2,065**	**2,136**
+/- Other	(129)	(136)	(13)	(29)	125	98
CFO Pre-WC	**1,623**	**1,858**	**2,041**	**2,096**	**2,190**	**2,234**
+/- ΔWC	(15)	25	(53)	(1,098)	243	108
CFO	**1,608**	**1,883**	**1,988**	**998**	**2,433**	**2,342**
- Div	593	638	723	770	696	674
- Capex	2,100	2,184	2,066	2,256	2,260	2,289
FCF	(1,085)	(939)	(801)	(2,028)	(523)	(621)
(CFO Pre-W/C) / Debt	20.1%	21.5%	22.6%	20.0%	19.1%	18.7%
(CFO Pre-W/C - Dividends) / Debt	12.7%	14.1%	14.6%	12.7%	13.0%	13.0%
FFO / Debt	21.6%	23.0%	22.8%	20.3%	18.0%	17.9%
RCF / Debt	14.3%	15.7%	14.8%	12.9%	12.0%	12.2%
Revenue	6,376	6,189	7,021	8,151	7,166	7,053
Interest Expense	312	332	315	342	455	482
Net Income	725	798	838	883	802	842
Total Assets	23,699	25,399	27,140	29,916	31,852	32,209
Total Liabilities	16,053	16,862	17,880	19,780	21,071	21,418
Total Equity	7,647	8,538	9,261	10,137	10,782	10,792

All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 11

Peer Comparison Table

	Consumers Energy Company (P)A3 Stable			DTE Electric Company (P)A2 Stable			DTE Gas Company A3 Stable			Northern States Power Company (Minnesota) A2 Stable			Wisconsin Power and Light Company Baa1 Stable		
(In $ millions)	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24
Revenue	8,151	7,166	7,053	6,397	5,804	5,895	1,894	1,726	1,736	6,684	6,043	5,913	1,856	1,827	1,817
CFO Pre-W/C	2,096	2,190	2,234	2,164	2,565	2,726	575	638	580	2,034	2,259	2,306	317	602	595
Total Debt	10,472	11,454	11,957	11,408	12,523	12,612	2,602	2,642	2,565	7,292	7,692	8,212	3,323	3,700	3,679
CFO Pre-W/C + Interest / Interest	7.1x	5.8x	5.6x	6.5x	6.7x	6.8x	7.2x	7.2x	6.4x	8.2x	7.8x	7.7x	4.5x	7.4x	6.6x
CFO Pre-W/C / Debt	20.0%	19.1%	18.7%	19.0%	20.5%	21.6%	22.1%	24.1%	22.6%	27.9%	29.4%	28.1%	9.5%	16.3%	16.2%
CFO Pre-W/C – Dividends / Debt	12.7%	13.0%	13.0%	12.3%	12.5%	13.6%	15.8%	16.9%	14.9%	20.2%	21.0%	20.2%	4.2%	11.3%	11.1%
Debt / Capitalization	45.1%	45.8%	46.7%	47.4%	48.4%	48.6%	44.5%	42.3%	39.4%	43.4%	43.0%	43.2%	43.8%	44.0%	43.5%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End; LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Ratings

Exhibit 12

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
LT IRB/PC	A3
Pref. Stock	Baa1
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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REPORT NUMBER 1409540

CLIENT SERVICES

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Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

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FitchRatings

Corporates
Electric-Corporate
United States

Consumers Energy Company

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

2035 Climate Vulnerability Signal: 44

Consumers Energy Company's ratings continue to derive support from its regulated utility operations in a constructive regulatory environment in Michigan. Sharpened focus on decarbonization and reliability is fueling the company's sizeable capex plans. Nevertheless, Fitch Ratings projects that Consumers Energy's funds from operations (FFO) leverage will average 4.1x through 2028, aided by increasing base rates and monetization of tax credits.

Key Rating Drivers

Constructive Regulatory Environment: Fitch believes the regulatory environment in Michigan under the Michigan Public Service Commission (MPSC) remains mostly constructive from a credit perspective. The regulatory framework allows for full pass-through of fuel costs and purchased power, forward-looking test years and a timely 10-month review period for general rate case resolution. Furthermore, Consumers Energy's authorized ROE of 9.9% compares favorably with industry averages.

Increasing storm activity in Michigan and resultant power outages have attracted regulatory focus on reliability. In March 2023, the MPSC tightened performance standards for utilities by way of enhanced outage credits, and updated reliability standards. An MPSC-led straw proposal for additional potential financial incentives and disincentives has also been underway since August 2023.

In Fitch's view, the risk of performance-based penalties is manageable within Consumers Energy's current credit profile. Fitch also does not expect a material negative outcome in the pending audit ordered by MPSC in October 2022 to assess the compliance of Consumers Energy with storm outages and safety regulations during the 2021 storms in Michigan. The final audit report is expected in summer 2024.

Electric Base Rate Case: In March 2024, the MPSC approved a largely constructive settlement authorizing an increase in Consumers Energy's annual rates by approximately $92 million based on a 9.9% authorized ROE and 50.02% equity thickness. The originally requested rate increase was $216 million, based on a 10.25% authorized ROE and 51.5% equity thickness, which was later reduced to $168.9 million by Consumers Energy.

In addition, the MPSC partially approved an infrastructure recovery mechanism for two years as well as an undergrounding pilot program. Fitch expects Consumers Energy's next electric rate case to be filed in 2Q24.

Gas Base Rate Case: In August 2023, the MPSC approved a largely constructive settlement authorizing an increase in Consumers Energy's annual rates by approximately $95 million, based on a 9.9% authorized ROE and 50.75% equity thickness, compared with a requested rate increase of $212 million, based on a 10.25% authorized ROE and 51.5% equity thickness. The rates allow for the recovery of new gas infrastructure investment and related costs.

In December 2023, Consumers Energy filed a gas rate case requesting an annual rate increase of $136 million, based on a 10.25% authorized ROE, 51.5% equity thickness and projected test year-ending September 2025. Fitch expects a decision in line with other recent decisions at MPSC by October 2024.

Applicable Criteria

Corporate Hybrids Treatment and Notching Criteria (November 2020)

Corporates Recovery Ratings and Instrument Ratings Criteria (October 2023)

Parent and Subsidiary Linkage Rating Criteria (June 2023)

Sector Navigators: Addendum to the Corporate Rating Criteria (November 2023)

Corporate Rating Criteria (November 2023)

Related Research

Global Corporates Macro and Sector Forecasts (March 2024)

North American Utilities, Power & Gas Dashboard: Fourth-Quarter 2023 (January 2024)

North American Utilities, Power & Gas Outlook 2024 (December 2023)

4Q23 North American Utilities Earnings Wrap Up Report (March 2024)

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Decarbonization and Reliability Driven Capex: Consumers Energy's current capital program is high at $17 billion for 2024-2028, increasing from $15.5 billion for 2023-2027. The increased capex is predominantly focused on system reliability and decarbonization initiatives, with 37% allocated for gas infrastructure, 43% for electric distribution and others and 20% for clean generation.

Consumers Energy is also on track to eliminate coal from its generation mix in 2025, replacing it with low-emitting gas and non-emitting renewable generation facilities. Consumers Energy was authorized to securitize previous coal retirements costs and has received proceeds of $646 million in 2023 Fitch expects continued regulatory support for Consumers Energy's future decarbonization efforts as well.

Fitch believes that an upward revision in capex is possible, given the increasing focus on reliability and the string of legislation passed in Michigan in 2023 that targets 100% clean generation by 2040 in Midcontinent Independent System Operator (MISO). Consumers Energy is expected to file its new renewable energy plan in 2H24. However, any concerns regarding the large capex plan are mitigated by the MPSC's constructive ratemaking policies and alignment of planned capex with state policy. Furthermore, the new energy legislation provides expanded incentives for energy efficiency, and could also lend improved economics for PPAs, which are beneficial in Fitch's view.

Supportive Financial Profile: Fitch believes Consumers Energy's FFO leverage will remain well within its sensitivities, averaging 4.1x through 2028. Any pressure from capex plans is largely offset by incremental earnings from rate-base growth, continued operation and maintenance savings and the ability to monetize tax credits on renewable projects using the tax credit transfer ability provisions of the Inflation Reduction Act.

Fitch forecasts Consumers Energy will sell about $400 million of tax credits over the forecast period using the tax credit transferability provisions of the Inflation Reduction Act. Fitch also assumes that any changes in the ability to monetize tax credits at the projected levels would result in adjustments to Consumers Energy's financial plan, supporting the current credit metrics.

Parent/Subsidiary Linkage: There is parent-subsidiary rating linkage between CMS and Consumers Energy. Fitch determines CMS's Standalone Credit Profile (SCP) based upon consolidated metrics. Fitch believes Consumers Energy's SCP to be stronger than CMS's SCP. Emphasis is placed on Consumers Energy'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 centrally manages the treasury function for all of its entities; however, both the parent and Consumers Energy issue their own long-term debt. Due to the aforementioned linkage considerations, Fitch will limit the difference between the Long-Term Issuer Default Ratings (IDR) of CMS and Consumers Energy to two notches.

Financial Summary

(USD Mil.)	2020	2021	2022	2023
Gross revenue	6,155	6,987	8,116	7,127
EBITDA	2,187	2,195	2,260	2,345
CFO (Fitch-defined)	1,186	1,948	954	2,387
FFO	1,239	1,974	2,052	2,144
Debt	8,318	8,727	10,230	10,613
FFO leverage (x)	5.5	3.9	4.4	4.2
FFO interest coverage (x)	5.3	8.0	8.1	6.2
EBITDA leverage (x)	3.8	4.0	4.5	4.5

Source: Fitch Ratings, Fitch Solutions

Rating Derivation Relative to Peers

The credit profile of Consumers Energy is comparable to peers like DTE Electric Company (A-/Stable), Northern States Power Company-Minnesota (A-/Stable) and Northern States Power Company-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 FFO leverage to average around 4.1x through 2028 at Consumers Energy. Financial metrics at its peers are marginally stronger, with leverage forecast to average 3.8x through 2026 at DTE and range 3.8x-4.0x for NSP-Wisconsin and 3.4x-3.8x for NSP-Minnesota through 2028.

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Rating Sensitivities

Factors that Could, Individually or Collectively, Lead to A 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.

Factors that Could, Individually or Collectively, Lead to A 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's Long-Term IDR.

Liquidity and Debt Structure

Adequate Liquidity: Consumers Energy primarily meets its short-term liquidity needs through the issuance of CP under its $500 million CP program, which is supported by its $1.1 billion revolving credit facility (RCF) as of year-end 2023. Consumers Energy's RCF will mature on Dec. 14, 2027 and is secured by the utility's first mortgage bonds (FMBs). Although the amount of outstanding CP does not reduce the RCF's available capacity, Consumers Energy states it would not issue CP in an amount exceeding the available RCF capacity.

Consumers Energy had $93 million of CP borrowings and $27 million of Letters of Credits outstanding as of year-end 2023, leaving $1 billion of unused availability under its RCF. Consumers Energy has a separate $250 million RCF that will mature on Nov. 18, 2025. This RCF had no borrowings, and $48 million of LCs outstanding at year-end 2023, leaving $202 million available. The facility is secured by the utility's FMBs.

CMS has a $550 million unsecured revolving credit facility (RCF) that will mature on Dec. 14, 2027. As of year-end 2023, CMS had $24 million of Letters of Credit outstanding and no borrowings outstanding, leaving $526 million of availability under its RCF. It also has a fully utilized LOC of $50 million as of Dec 31, 2023, which terminates in September 2024.CMS Energy's operations require modest cash on hand. The company had $237 million of unrestricted cash and cash equivalents at Dec. 31, 2023, $35 million of which was at Consumers Energy.

At the parent level, CMS has $250 million of bonds expiring in 2025 followed by $300 million in 2026, $625 million in 2027 and $800 million in 2028. Consumers Energy has bond maturities of $302 million in 2024 and subsequently lower maturities of $116 million in 2025, $237 million in 2026, $263 million in 2027 and $843 million in 2028. In Fitch's view, the aforementioned debt maturities remain manageable given the company's history of successful refinancing. Fitch expects CMS and Consumers Energy to have continued access to the capital markets.

CMS and Consumers Energy were compliant with consolidated debt/capitalization of 70% and 65%, respectively, as defined under the credit agreement, as of Dec. 31, 2023.

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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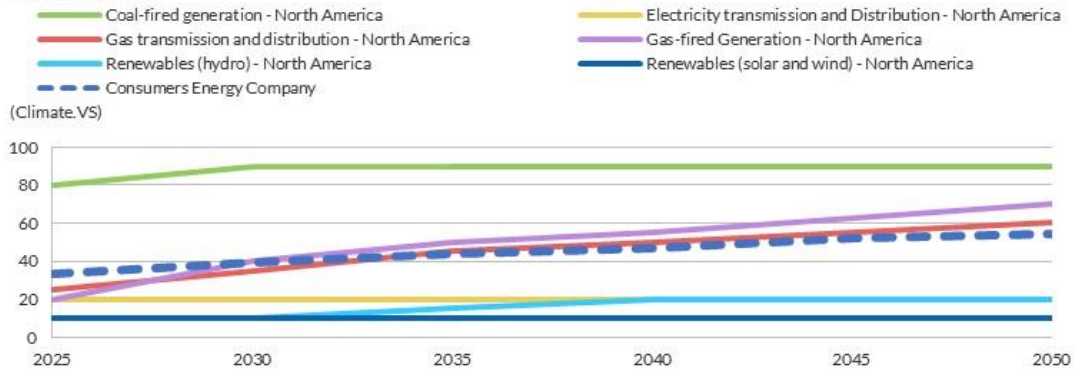
Climate Vulnerability Considerations

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.

The 2023 asset-weighted Climate.VS for Consumers Energy is 44 for 2035 out of 100. The utility's Climate.VS is a function of ownership of around 1.4 gigawatts (GW) of coal-fired generating capacity and 2.5GW 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 plans to phase out coal generation in 2025. By 2040, Consumers Energy expects to move towards a portfolio supported by around 61% renewable energy generation as it adds solar, wind and storage For further information on how Fitch perceives climate-related risks in the utilities sector, see Utilities–Long-Term Climate Vulnerability Signals Update.

Climate.VS Evolution
As of Dec. 31, 2023



Source: Fitch Ratings

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Liquidity and Debt Maturities

Cash and maturities report (USD Mil.)	Dec. 31, 2022	Dec. 31, 2023
Total cash and cash equivalents	60	56
Short-term investments		
Less not readily available cash and cash equivalents	17	21
Fitch-defined readily available cash and cash equivalents	**43**	**35**
Availability under committed lines of credit	1,274	1,182
Total liquidity	1,317	1,217
LTM EBITDA after associates and minorities	2,260	2,345
LTM FCF	-2,056	-1,368

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Scheduled debt maturities (USD Mil.)	December 31, 2023
2024	395
2025	116
2026	237
2027	263
2028	843
Thereafter	8,777
Total	**10,631**

Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

Key Assumptions

Fitch's Key Assumptions Within Its Rating Case for the Issuer Include:

- Constructive regulatory environment in Michigan with authorized ROE of 9.9% for both electric and gas utility operations;
- Gas rate case decision in 4Q24;
- Annual rate case filings;
- Largely flat annual electric and natural gas sales;
- Total utility capex in line with management's assumptions;
- Dividend growth of 6%-8% a year;
- Normal weather;
- No material equity issuances in 2024 (other than the conversion of equity forwards and CMS's running Dividend Reinvestment Plan and subsequently up to $350 million annually through 2028.

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Financial Data

(USD Mil.)	2020	2021	2022	2023
Summary income statement				
Gross revenue	6,155	6,987	8,116	7,127
Revenue growth (%)	-2.9	13.5	16.2	-12.2
EBITDA before income from associates	2,187	2,195	2,260	2,345
EBITDA margin (%)	35.5	31.4	27.9	32.9
EBITDA after associates and minorities	2,187	2,195	2,260	2,345
EBITDAR	2,187	2,195	2,260	2,345
EBITDAR margin (%)	35.5	31.4	27.9	32.9
EBIT	1,197	1,152	1,212	1,249
EBIT margin (%)	19.4	16.5	14.9	17.5
Gross interest expense	-298	-291	-316	-416
Pretax income including associate income/loss	989	1,024	1,085	1,028
Summary balance sheet				
Readily available cash and equivalents	20	22	43	35
Debt	8,318	8,727	10,230	10,613
Lease-adjusted debt	8,318	8,727	10,230	10,613
Net debt	8,298	8,705	10,187	10,578
Summary cash flow statement				
EBITDA	2,187	2,195	2,260	2,345
Cash interest paid	-283	-277	-290	-401
Cash tax	-51	10	2	-31
Dividends received less dividends paid to minorities (inflow/outflow)	—	—	—	—
Other items before FFO	-622	40	73	203
FFO	1,239	1,974	2,052	2,144
FFO margin (%)	20.1	28.3	25.3	30.1
Change in working capital	-53	-26	-1,098	243
CFO (Fitch-defined)	1,186	1,948	954	2,387
Total non-operating/nonrecurring cash flow	—	—	—	—
Capex	-2,170	-2,052	-2,239	-3,060
Capital intensity (capex/revenue) (%)	35.3	29.4	27.6	42.9
Common dividends	-639	-724	-771	-695
FCF	-1,623	-828	-2,056	-1,368
FCF margin (%)	-26.4	-11.9	-25.3	-19.2
Net acquisitions and divestitures	58	—	—	—
Other investing and financing cash flow items	-163	-131	-87	-121
Net debt proceeds	1,085	393	1,474	1,010
Net equity proceeds	650	575	685	475
Total change in cash	7	9	16	-4
Leverage ratios (x)				
EBITDA leverage	3.8	4.0	4.5	4.5
EBITDA net leverage	3.8	4.0	4.5	4.5
EBITDAR leverage	3.8	4.0	4.5	4.5
EBITDAR net leverage	3.8	4.0	4.5	4.5
FFO adjusted leverage	5.5	3.9	4.4	4.2
FFO adjusted net leverage	5.5	3.9	4.4	4.2
FFO leverage	5.5	3.9	4.4	4.2
FFO net leverage	5.5	3.9	4.4	4.2

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(USD Mil.)	2020	2021	2022	2023
Calculations for forecast publication				
Capex, dividends, acquisitions and other items before FCF	-2,751	-2,776	-3,010	-3,755
FCF after acquisitions and divestitures	-1,565	-828	-2,056	-1,368
FCF margin after net acquisitions (%)	-25.4	-11.9	-25.3	-19.2
Coverage ratios (x)				
FFO interest coverage	5.3	8.0	8.1	6.2
FFO fixed-charge coverage	5.3	8.0	8.1	6.2
EBITDAR fixed-charge coverage	7.7	7.9	7.8	5.8
EBITDAR net fixed-charge coverage	7.9	8.1	8.0	6.3
EBITDA interest coverage	7.7	7.9	7.8	5.8
Additional metrics (%)				
CFO-capex/debt	-11.8	-1.2	-12.6	-6.3
CFO-capex/net debt	-11.9	-1.2	-12.6	-6.4
CFO/capex	54.6	94.9	42.6	78.0
REIT fixed-charge coverage (x)	7.7	7.9	7.7	5.8
REIT leverage (x)	3.8	4.0	4.5	4.5

CFO – Cash flow from operations
Source: Fitch Ratings, Fitch Solutions

How to Interpret the Forecast Presented

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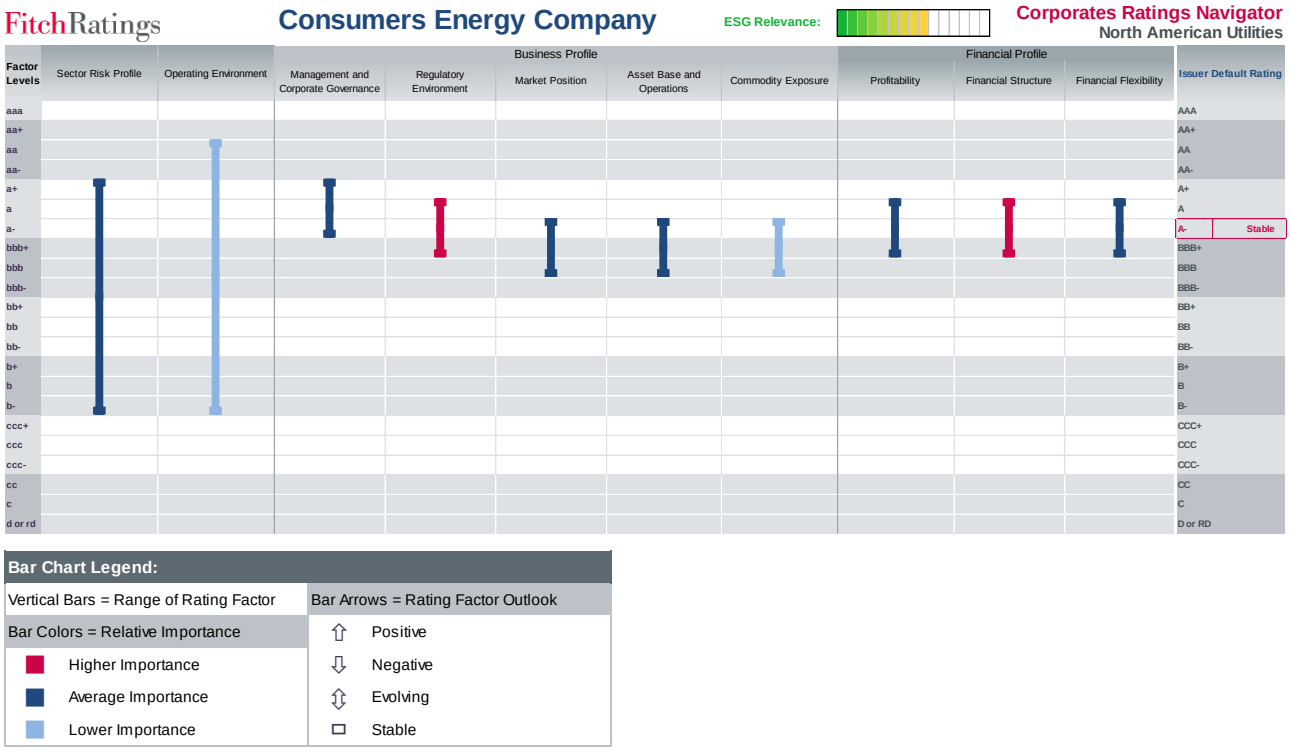

Bar Chart Legend:	
Vertical Bars = Range of Rating Factor	Bar Arrows = Rating Factor Outlook
Bar Colors = Relative Importance	⇧ Positive
Higher Importance	⇩ Negative
Average Importance	⇳ Evolving
Lower Importance	▭ Stable

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Consumers Energy Company

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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				
Impact of waste from operations	potential driver	12	issues	3
Plants' and networks' exposure to extreme weather				
Product affordability and access	not a rating driver	2	issues	2
Quality and safety of products and services; data security		0	issues	1

Showing top 6 issues

For further details on Credit-Relevant ESG scoring, see page 3.

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FitchRatings

Corporates
Electric-Corporate
United States

FitchRatings

Consumers Energy Company

Corporates Ratings Navigator
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: 5, 4, 3, 2, 1

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: 5, 4, 3, 2, 1

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: 5, 4, 3, 2, 1

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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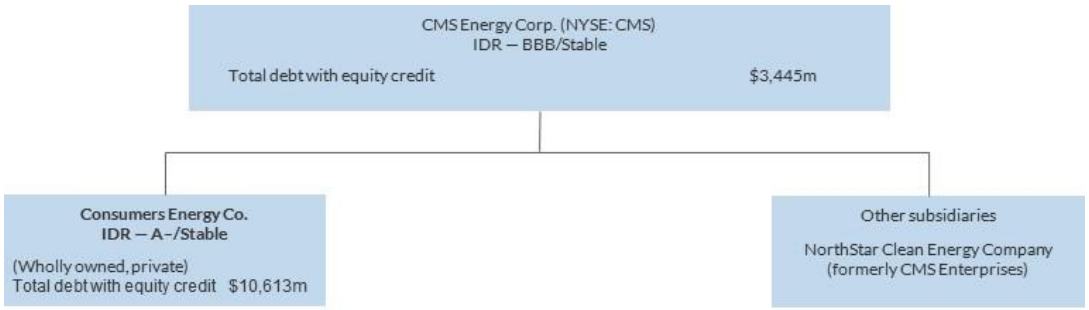
Simplified Group Structure Diagram



Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company, as of April 2024

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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-	2023	7,127	2,144	4.2	6.2	4.5
	A-	2022	8,116	2,052	4.4	8.1	4.5
	A-	2021	6,987	1,974	3.9	8.0	4.0
DTE Electric Company							
	A-	2023	5,804	1,968	4.5	5.6	4.1
	A-	2022	6,397	2,463	3.6	7.8	4.0
	A-	2021	5,809	1,842	4.2	6.5	3.8
Northern States Power Company-Minnesota							
	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-	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

Source: Fitch Ratings, Fitch Solutions

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Fitch Adjusted Financials

(USD Mil. as of Dec. 31, 2023)	Notes and formulas	Standardised values	Other adjustments	Lease treatment	Other adjustments	Adjusted values
Income statement summary						
Revenue		7,166	–	–	-39	7,127
EBITDA	(a)	2,405	–	-21	-39	2,345
Depreciation and amortization		-1,137	–	8	33	-1,096
EBIT		1,268	–	-13	-6	1,249
Balance sheet summary						
Debt	(b)	11,299	–	–	-787	10,613
Of which other off-balance-sheet debt		–	–	–	–	–
Lease-equivalent debt		–	–	–	–	–
Lease-adjusted debt		11,299	–	–	-787	10,613
Readily available cash and equivalents	(c)	35	–	–	–	35
Not readily available cash and equivalents		21	–	–	–	21
Cash flow summary						
EBITDA	(a)	2,405	–	-21	-39	2,345
Dividends received from associates less dividends paid to minorities	(d)	–	–	–	–	–
Interest paid	(e)	-417	–	13	-9	-413
Interest received	(f)	30	–	–	–	30
Preferred dividends paid	(g)	-2	–	–	–	-2
Cash tax paid		-31	–	–	–	-31
Other items before FFO		200	–	–	15	215
FFO	(h)	2,185	–	-8	-33	2,144
Change in working capital		243	–	–	–	243
CFO	(i)	2,428	–	-8	-33	2,387
Non-operating/nonrecurring cash flow		–	–	–	–	–
Capex	(j)	-3,060	–	–	–	-3,060
Common dividends paid		-695	–	–	–	-695
FCF		-1,327	–	-8	-33	-1,368
Gross leverage (x)						
EBITDA leverage	b / (a+d)	4.7	–	–	–	4.5
FFO leverage	b / (h-e-f-g)	4.4	–	–	–	4.2
(CFO-capex)/debt (%)	(i+j) / b	-5.5	–	–	–	-6.3
Net leverage (x)						
EBITDA net leverage	(b-c) / (a+d)	4.7	–	–	–	4.5
FFO net leverage	(b-c) / (h-e-f-g)	4.4	–	–	–	4.2
(CFO-capex)/net debt (%)	(i+j) / (b-c)	-5.6	–	–	–	-6.4
Coverage (x)						
EBITDA interest coverage	(a+d) / (-e)	5.8	–	–	–	5.7
FFO interest coverage	(h-e-f-g) / (-e-g)	6.1	–	–	–	6.1

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 $44 million.
Source: Fitch Ratings, Fitch Solutions, Consumers Energy Company

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Parent Subsidiary Linkage Analysis

Parent	CMS Energy Corporation
Parent LT IDR	BBB/Stable
Subsidiary	Consumers Energy Company
Subsidiary LT IDR	A-/Stable
Path	Stronger Subsidiary
Legal ring-fencing	Porous
Access and control	Porous
Notching matrix outcome	Consolidated Plus 2
Override applied	No
Notching approach	Consolidated Plus 2

LT IDR – Long-Term Issuer Default Rating
Source: Fitch Ratings

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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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Peer Company Revolver Capacity Analysis

Source: S&P Capital IQ

Case No.: U-21870
Exhibit No.: A-39 (MRB-20)
Page: 1 of 1
Witness: MRBleckman
Date: June 2025

(a)	(b)	(c)	(d)	(e)	(f)	(g)
				Dec 31, 2024 (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	300,000	9,336,000	
2			Wisconsin Power and Light Company	400,000	8,861,000	
3				700,000	18,197,000	3.8%
4						
5	Ameren Corporation	AEE	Ameren Illinois Company	1,200,000	15,530,000	
6			Union Electric Company	1,400,000	18,857,000	
7				2,600,000	34,387,000	7.6%
8						
9	Dominion Resources, Inc.	D	Dominion Energy South Carolina, Inc.	500,000	11,698,000	
10			Virginia Electric and Power Company	1,750,000	52,927,000	
11				2,250,000	64,625,000	3.5%
12						
13	DTE Energy Company	DTE	DTE Electric Company	800,000	23,060,000	
14			DTE Gas Company	300,000	6,661,000	
15				1,100,000	29,721,000	3.7%
16						
17	Duke Energy Corporation	DUK	Duke Energy Carolinas, LLC	1,400,000	39,390,000	
18			Duke Energy Florida, LLC	875,000	23,117,000	
19			Duke Energy Indiana, LLC	950,000	13,159,000	
20			Duke Energy Kentucky, Inc.	225,000	2,399,546	
21			Duke Energy Ohio, Inc.	1,050,000	10,250,000	
22			Duke Energy Progress, LLC	1,500,000	26,478,000	
23			Piedmont Natural Gas Company, Inc.	950,000	10,352,000	
24			Progress Energy, Inc.	2,375,000	49,599,000	
25				9,325,000	174,744,546	5.3%
26						
27	Entergy Corporation	ETR	Entergy Arkansas, LLC	405,000	10,674,012	
28			Entergy Louisiana, LLC	610,000	19,435,290	
29			Entergy Mississippi, LLC	300,000	5,841,073	
30			Entergy New Orleans, LLC	25,000	1,453,408	
31			Entergy Texas, Inc.	300,000	7,592,834	
32			System Energy Resources, Inc.	120,000	2,394,715	
33				1,760,000	47,391,332	3.7%
34						
35	Evergy, Inc.	EVRG	Evergy Kansas Central, Inc.	1,100,000	13,024,000	
36			Evergy Metro, Inc.	600,000	8,321,700	
37			Evergy Missouri West, Inc.	500,000	3,775,800	
38				2,200,000	25,121,500	8.8%
39						
40	IDACORP, Inc.	IDA	Idaho Power Company	400,000	6,505,685	6.1%
41						
42	NextEra Energy, Inc.	NEE	Florida Power & Light Company	4,500,000	76,166,000	5.9%
43						
44	OGE Energy Corporation	OGE	Oklahoma Gas and Electric Company	550,000	11,531,900	4.8%
45						
46	Pinnacle West Capital Corporation	PNW	Arizona Public Service Company	1,250,000	20,210,913	6.2%
47						
48	TXNM Energy	TXNM	Public Service Company of New Mexico	440,000	5,404,167	
49			Texas-New Mexico Power Company	200,000	3,198,396	
50				640,000	8,602,563	7.4%
51						
52	PPL Corporation	PPL	Kentucky Utilities Company	400,000	8,334,000	
53			Louisville Gas and Electric Company	500,000	6,548,000	
54			PPL Electric Utilities Corporation	650,000	13,315,000	
55			The Narragansett Electric Company	250,000	4,920,000	
56				1,800,000	33,117,000	5.4%
57						
58	Southern Company	SO	Alabama Power Company	1,365,000	26,893,000	
59			Georgia Power Company	2,050,000	45,369,000	
60			Mississippi Power Company	275,000	4,125,000	
61			Southern Company Gas	1,600,000	17,546,000	
62				5,290,000	93,933,000	5.6%
63						
64	Xcel Energy Inc.	XEL	Northern States Power Company - MN	700,000	21,253,000	
65			Northern States Power Company - WI	150,000	3,670,000	
66			Public Service Company of Colorado	700,000	23,609,000	
67			Southwestern Public Service Company	500,000	9,622,000	
68				2,050,000	58,154,000	3.5%
69						
70						
71	Average Proxy Group					5.4%
72						
73						
74			**Consumers Energy**	**1,350,000**	**25,580,000**	**5.3%**

Industry Credit Outlook 2025

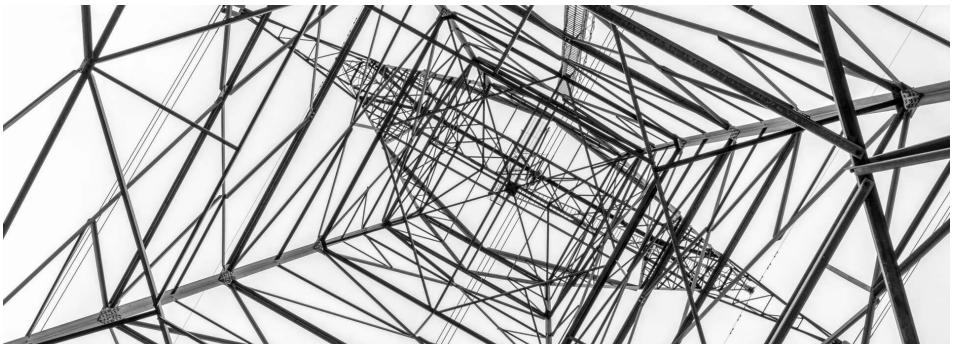
S&P Global Ratings

North America Regulated Utilities

Capex and climate change pressures credit quality

January 14, 2025

This report does not constitute a rating action.



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What's changed?

Lower ratings headroom. A high percentage of companies are operating with only minimal financial cushion from our downgrade threshold.

Rising capital spending, higher cash flow deficits, and increased wildfire risks led to downgrades outpacing upgrades for the fifth consecutive year.

Data centers spur electricity sales growth at about 1% annually, which will provide modest support to credit quality.

What are the key assumptions for 2025?

High cash flow deficits of about $100 billion, which could harm financial performance if not funded in a credit-supportive manner.

Robust dividends of about $50 billion for 2025 and at a dividend payout ratio of about 60%.

Record amount of hybrid securities. The industry issued $26 billion of them in 2024, and we expect this trend will persist.

What are the key risks around the baseline?

Rising wildfire risks stemming from climate change.

Tax legislation could weaken financial measures if the new Republican administration lowers the corporate tax rate, reduces tax credits, or eliminates their transferability.

Common equity issuance is below our base-case expectations, and has been for the last several years, leading to weaker financial measures.

Ratings Trends: North America Regulated Utilities

Chart 1

Ratings distribution

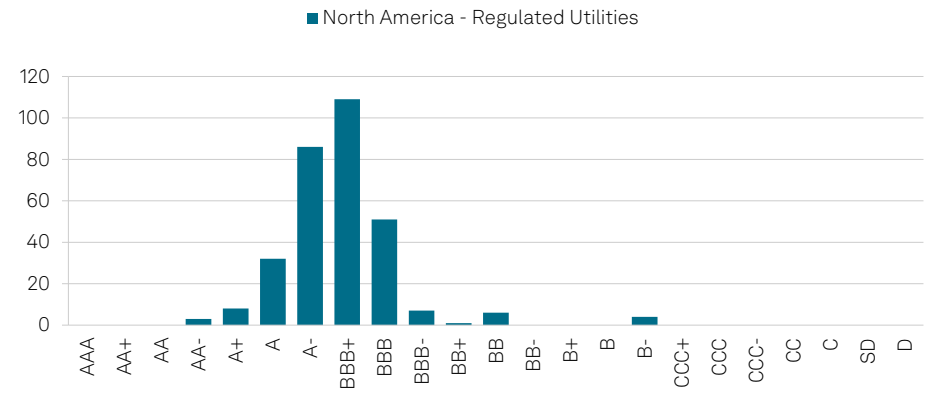


Chart 2

Ratings outlooks

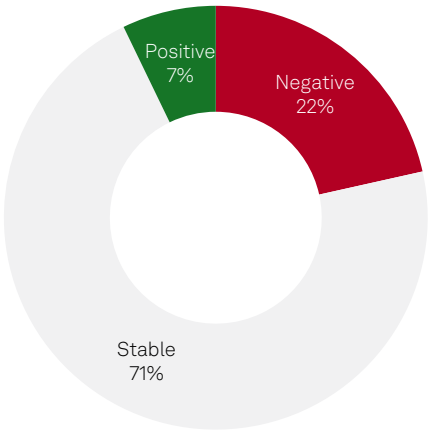
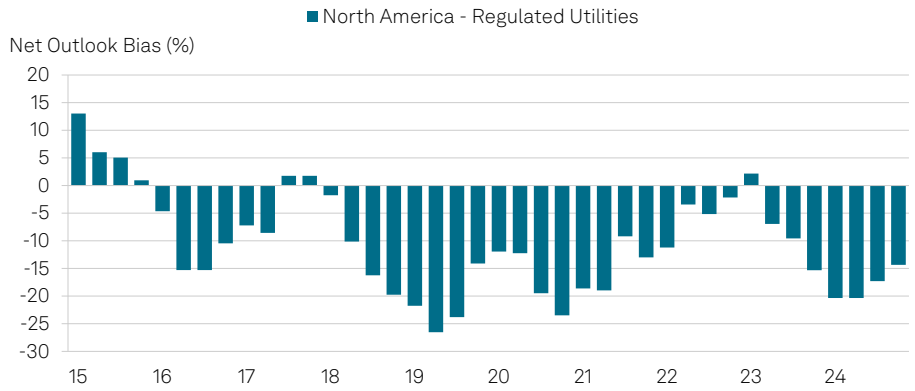


Chart 3

Ratings outlook net bias



Source: S&P Global Ratings. Ratings data measured at quarter-end.

Industry Credit Metrics: North America Regulated Utilities

Chart 4

Debt / EBITDA (median, adjusted)

Chart 5

FFO / Debt (median, adjusted)

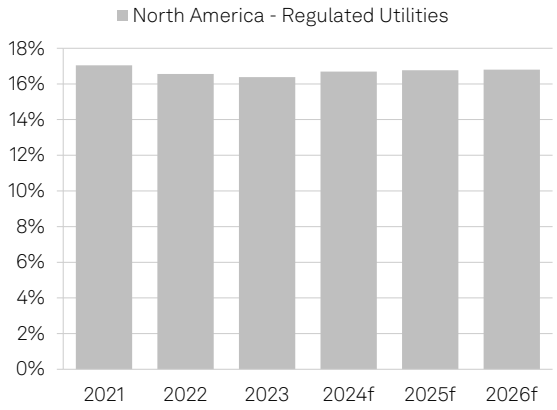


Chart 6

Cash flow and primary uses

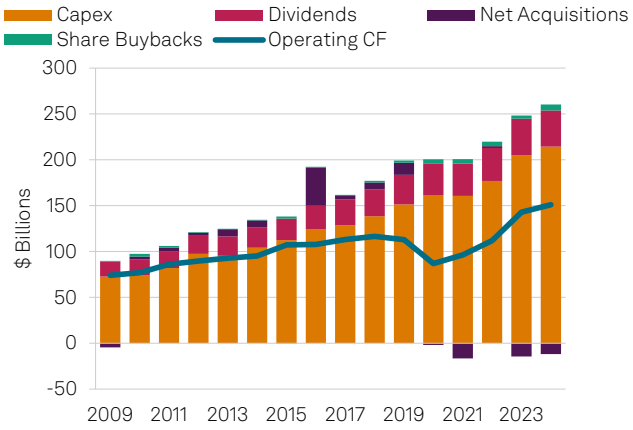
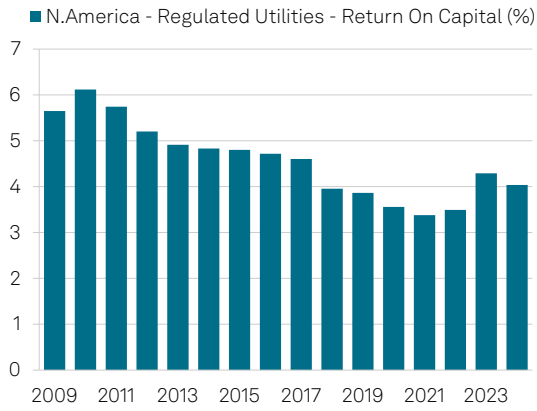


Chart 7

Return on capital employed



Source: S&P Global Ratings, S&P Capital IQ.
Revenue growth shows local currency growth weighted by prior-year common-currency revenue share. All other figures are converted into U.S. dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO—Funds from operations. Most recent (2024) figures for cash flow and primary uses and return on capital employed use the last 12 months' data.

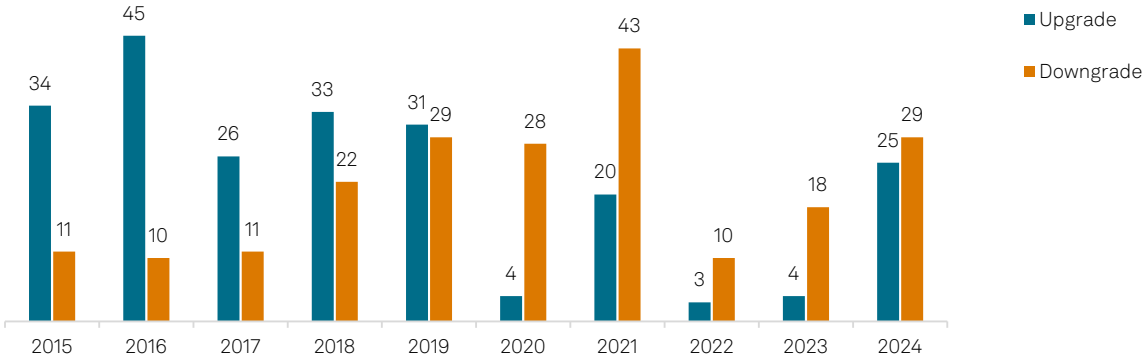
Industry Outlook

Ratings trends and outlook

In 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year (see chart 8). Most were directly attributable to rising wildfire risks, robust capital spending, and challenging regulatory constructs. We expect these risks will persist for 2025, further pressuring the industry's credit quality.

Chart 8

North America regulated utilities' upgrades and downgrades



Source: S&P Global Ratings.

Main assumptions about 2025 and beyond

1. Record capital spending.

The industry is heavily investing in safety, reliability, energy transition, and data centers. We expect this spending will exceed $300 billion before the end of the decade.

2. Management of regulatory risk.

This includes constructive rate case orders, minimizing regulatory lag, and earning the authorized return on equity (ROE).

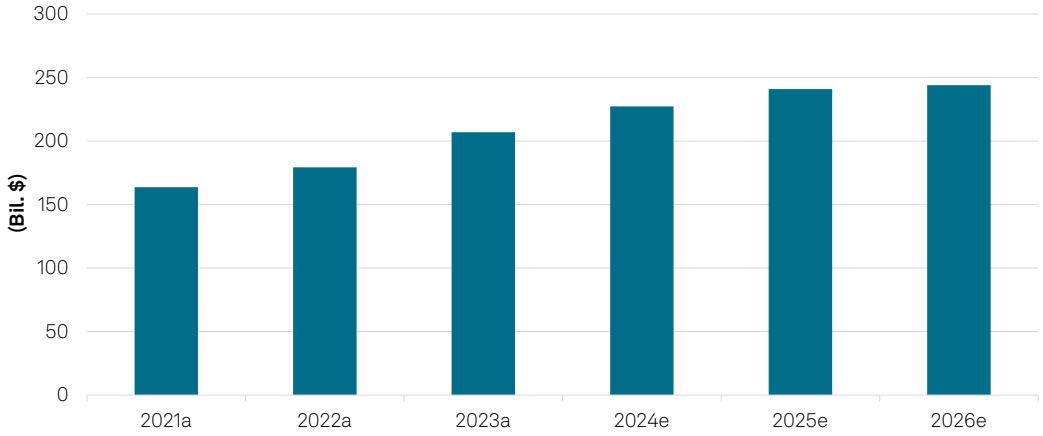
3. Climate change increases risks.

The growing frequency of devastating physical events, including hurricanes, storms, and wildfires, is elevating the industry's credit risks.

Capital spending continues to break records. We expect capital spending for North America's electric, gas, and water utilities will grow by a compound annual growth rate (CAGR) of about 10%. Accordingly, we expect 2025 capital spending to reflect about $240 billion (see chart 9). To date, the industry's capital spending has been primarily focused on safety, reliability, and energy transition.

Chart 9

North America regulated utilities' rising capital expenditures

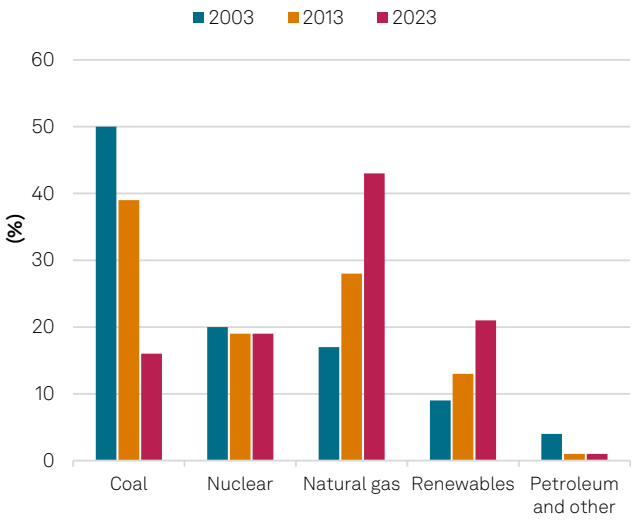


a—Actual. e—Estimate. Capital expenditures represent North American investor-owned electric gas, and water utilities.
Source: S&P Global Ratings.

Energy transition remains key. Over the past decade the industry has invested billions on reducing its reliance on coal-fired generation by about 50% (see chart 10), and today, coal represents only about 15% of total electric generation. Most of the coal was replaced with natural gas, which has about half the carbon emissions. We expect the industry will replace most of its remaining coal-fired generation by about 2030 with renewables and batteries, further reducing its carbon and greenhouse gas (GHG) emissions. The industry has reduced its GHG emissions by nearly 30% over the past decade (see chart 11), and we expect it will reduce them by another 30% by 2035.

Chart 10

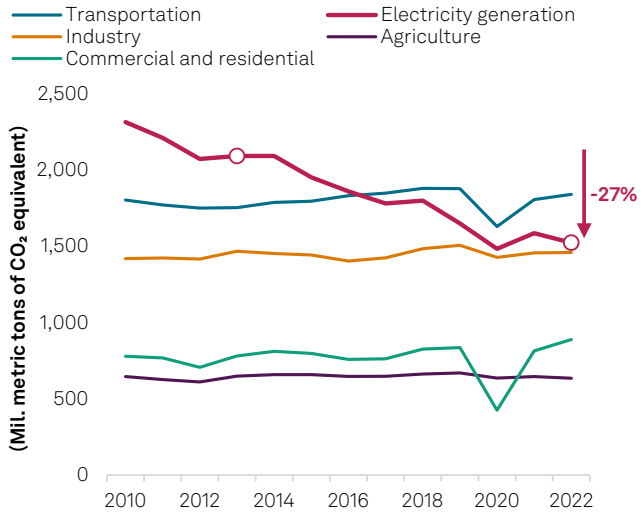
U.S. generation transformation



Source: U.S. Energy Information Administration.

Chart 11

GHG emissions by economic sector (2010-2022)

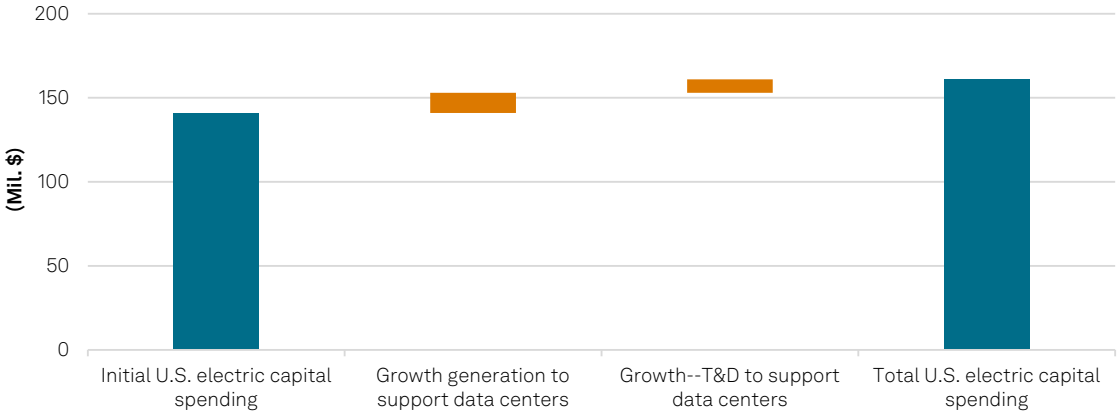


Source: U.S. Environmental Protection Agency.

Data center growth is relatively new, and our current base-case assumptions do not fully incorporate the incremental spending necessary for it. The higher spending for data centers is more likely to begin in 2026. Accordingly, 2026 capex could potentially increase by about another 15% above our current base case (see chart 12).

Chart 12

Data center growth will increase U.S. electric utility annual capital spending by about 15%

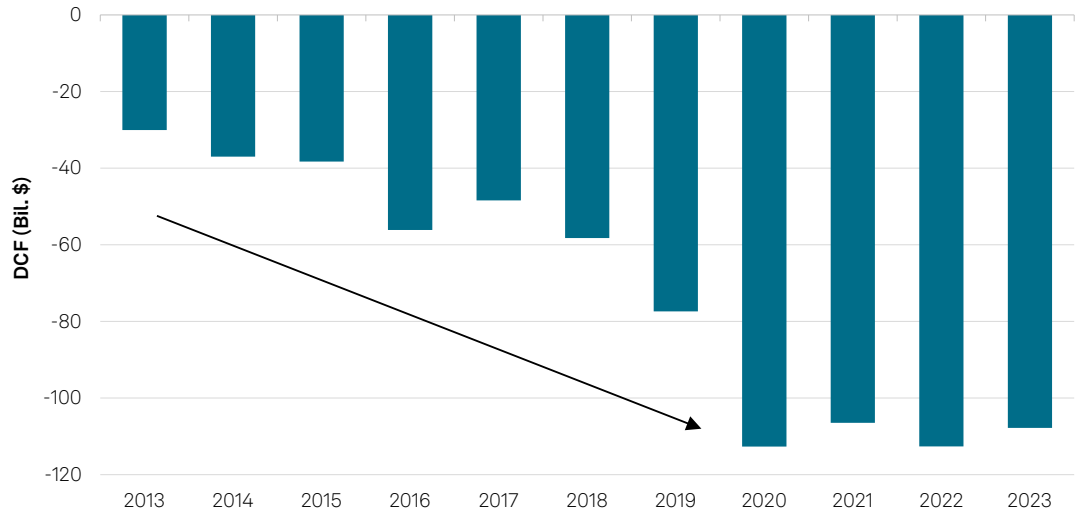


T&D—Transmission and distribution. Source: S&P Global Ratings.

Cash flow deficits will rise as a result, increasing the pressure on the industry's credit quality. Over the past decade the industry's cash flow deficits have grown from about $50 billion to consistently over $100 billion (see chart 13), and we expect this trend will continue.

Chart 13

North America regulated utilities' cash flow deficits



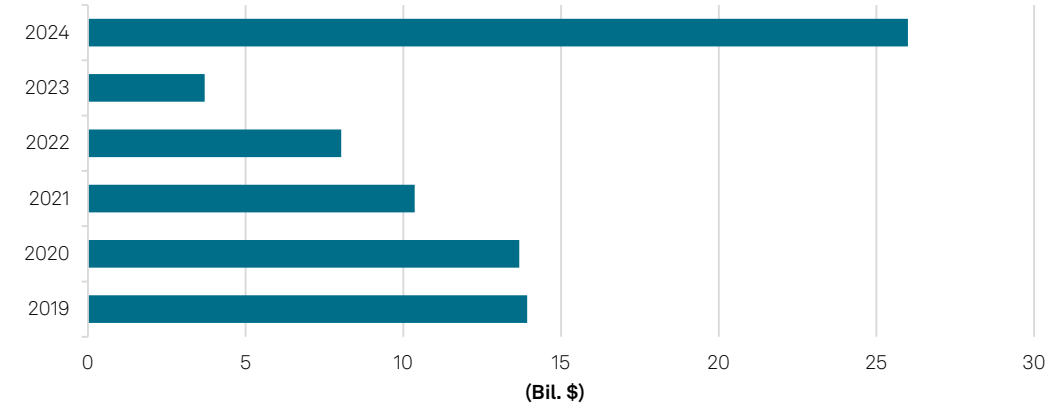
DCF—Discretionary cash flow. Sources: S&P Global Capital IQ, S&P Global Ratings.

Hybrid security issuance reached an all-time high of about $26 billion in 2024, far exceeding the previous record of about $14 billion in 2019 (see chart 14). We expect the industry will maintain this level of issuance in 2025 given its increased capital spending. This robust issuance supported the industry's 2024 financial measures because we typically assess hybrid securities as more

credit supportive than debt, with most of these securities having intermediate (50%) or high (100%) equity content.

Chart 14

North America regulated utilities' annual hybrid securities issuance

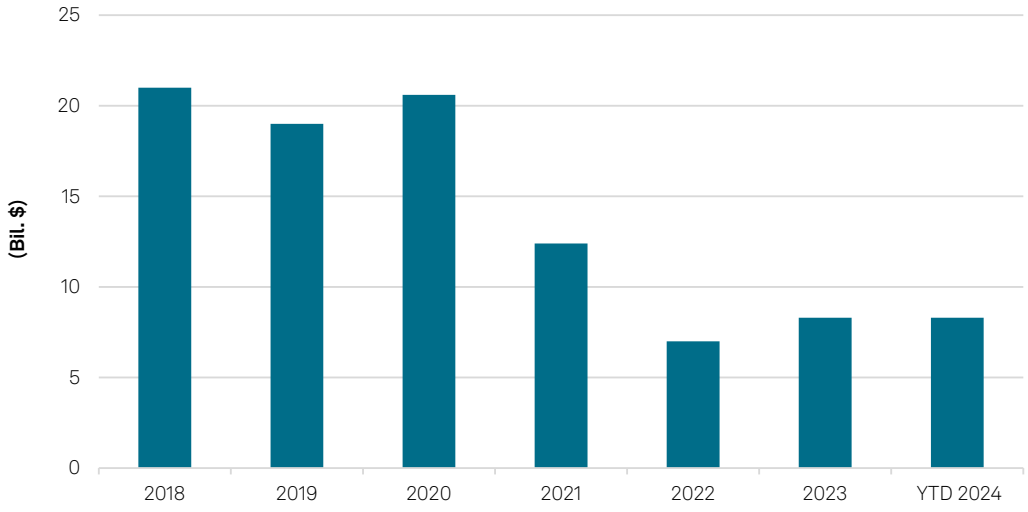


Sources: S&P Global Ratings, S&P Global Market Intelligence.

Common equity issuance has been weak and consistently below our expectations since 2021, pressuring the industry's financial measures. It raised only about $8 billion in 2024, and we estimate that the full year will reflect only about $10 billion. This is well below the industry's average run rate of about $20 billion annually between 2018-2020 (see chart 15). We expect 2025 common equity issuance will again be relatively weak and more reflective of 2024 levels. Without significantly more common equity issuance, we expect the industry's financial measures will continue to weaken, albeit gradually, supporting our negative outlook.

Chart 15

North America regulated utilities' common equity issuance



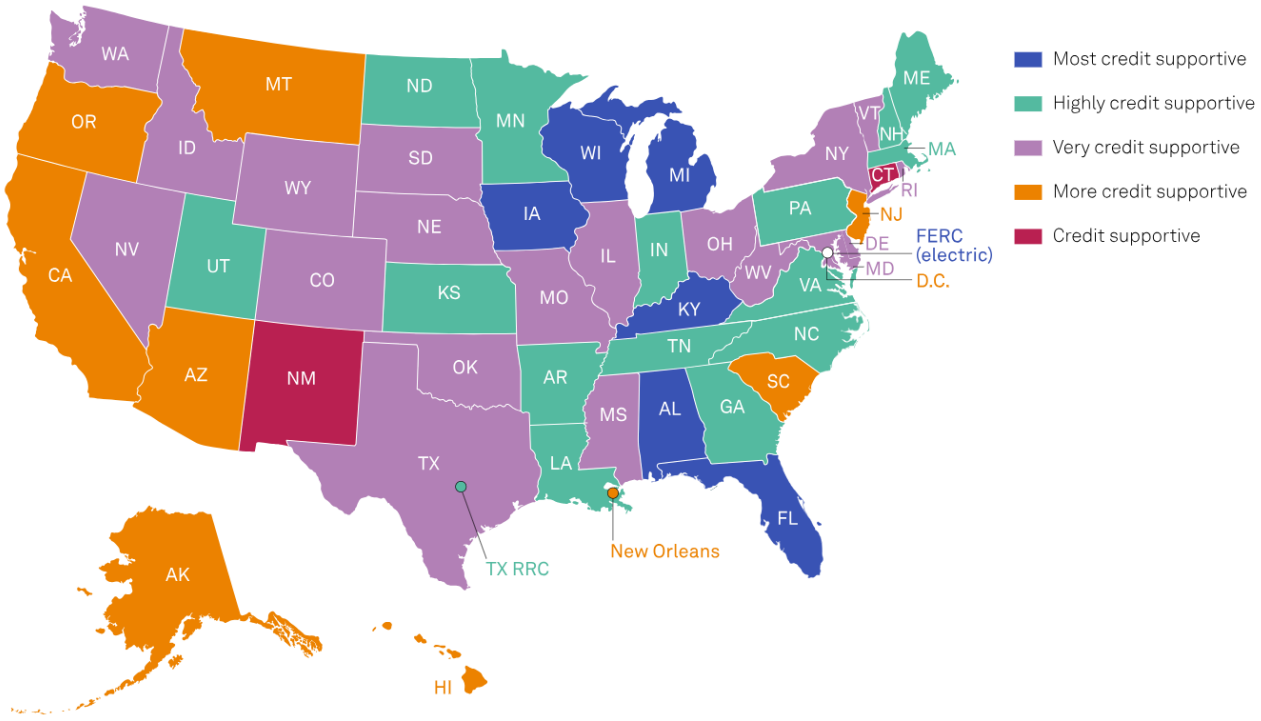
YTD—Year-to-date as of Dec. 15, 2024. Sources: S&P Global Ratings, S&P Global Market Intelligence.

Effective management of regulatory risk will continue. We assess all North America's regulatory jurisdictions as credit supportive or better, reflecting the industry's generally stable and predictable cash flows (see chart 16). 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 (that is, the timing difference between when a utility incurs costs and when it's recovered from ratepayers).

Chart 16

Regulatory assessment by state

As of November 2024



Source: S&P Global Ratings.

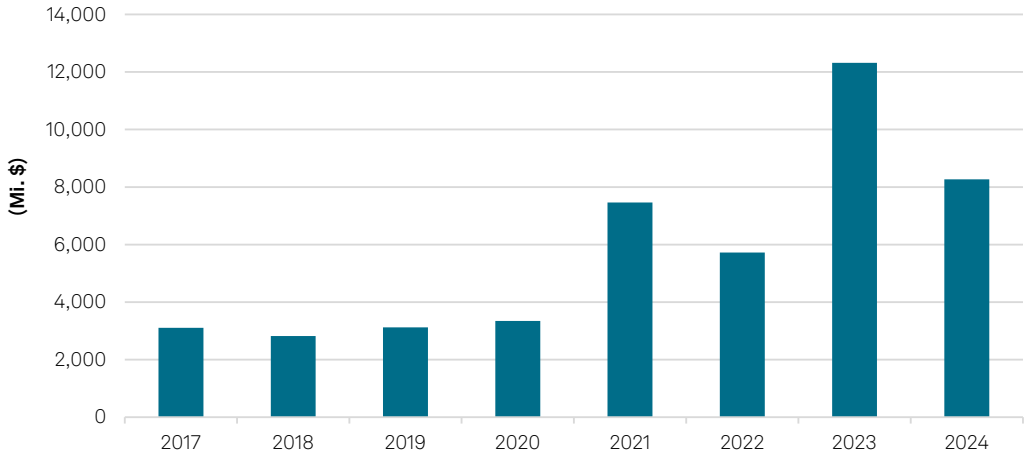
In general, we expect utilities will operate in a regulatory jurisdiction that is supportive of their credit quality by allowing for the full recovery of all their operating and capital costs in a timely manner. We also expect the regulatory jurisdiction will provide a consistent and predictable regulatory framework that results in cash flow stability. Our view of the industry's regulatory constructs supports the industry's mostly investment-grade ratings despite the industry continuing to operate with material cash flow deficits.

Recently, we revised downward our assessment of Connecticut's regulatory construct to credit supportive from more credit supportive. We now expect the state's regulated utilities will be increasingly subject to below-average authorized ROEs, regulatory lag, and an inconsistent ability to earn their lower authorized ROEs. These developments will increase the utilities' cash flow volatility, decrease the stability of their financial performances, and weaken their ability to consistently manage regulatory risk. Other regulatory jurisdictions that we continue to carefully monitor include Arizona, Colorado, District of Columbia, Illinois, Maryland, Michigan, New Mexico, Texas, and West Virginia.

Regulatory rate case order increases have substantially risen over the past four years, reflecting the industry's robust capital spending. Rate case increases for 2021-2024 have increased by more than 2.5x compared to 2017-2020 (see chart 17), and there are more than 100 U.S. rate cases pending, for which utilities are requesting over $16 billion more in revenue. This is in line with our base case that this year's rate case orders will again be robust and most likely in the top three years for rate case order increases.

Chart 17

U.S. rate case orders

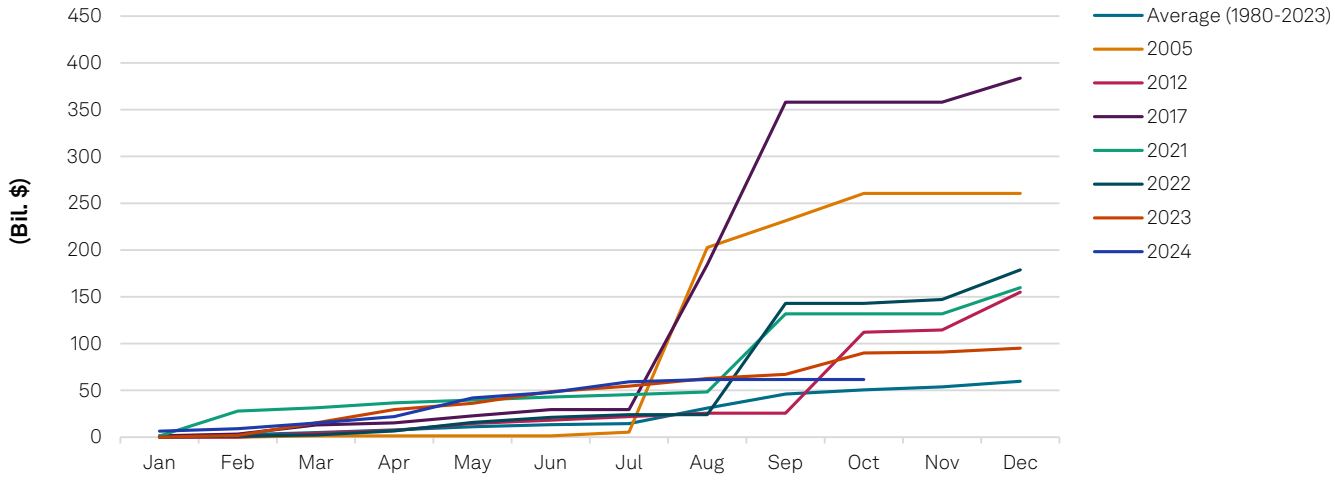


Source: S&P Global Commodity Insights.

Utilities' exposure to physical risks are increasing. According to the National Oceanic and Atmospheric Administration (NOAA), on an inflation-adjusted basis, 2021 and 2022 represent two of the most destructive years for extreme weather events since 1980 (see chart 18). We assume these trends will persist, magnifying physical risks for the utility industry.

Chart 18

U.S. billion-dollar weather disaster year-to-date event cost (CPI-adjusted)



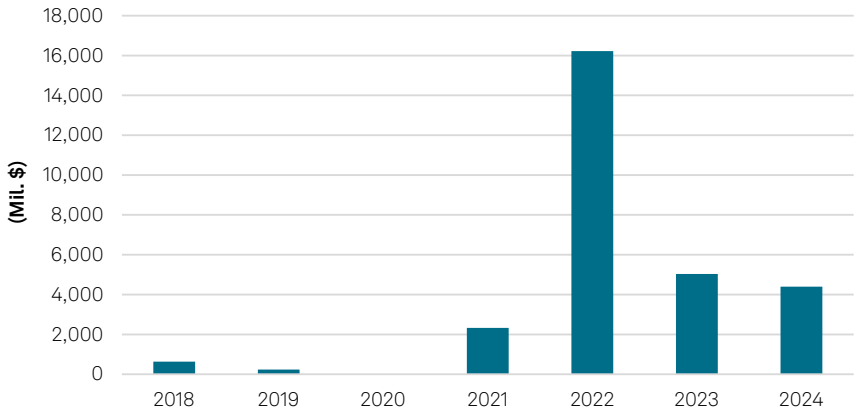
Source: National Ocean and Atmospheric Administration.

Drier, hotter weather has increased the acreage designated as high-fire-risk across the U.S. This is already taking a toll on credit ratings. For example, in 2024 we downgraded parent Xcel Energy Inc. and subsidiary Southwestern Public Service Co. (SPS) because of the scale and severity of the wildfires in the Texas panhandle, which highlights their increasing wildfire exposure. Overall, because of climate change, we expect the industry's wildfire risk will increase.

Securitization increased, which we assess as supportive of credit quality (see chart 19). Securitization allows for the issuance of debt secured by a non-bypassable charge to the customer's bill, allowing the utility to fully recover storm-related costs at a lower interest rate for customers. Because the debt is secured by the high likelihood of customers paying their bills, the associated interest costs are typically lower. We often deconsolidate such debt, resulting in stronger credit measures.

Chart 19

S&P Global Ratings-rated utility-related securitization issuance (2018-2024)



Source: S&P Global Ratings.

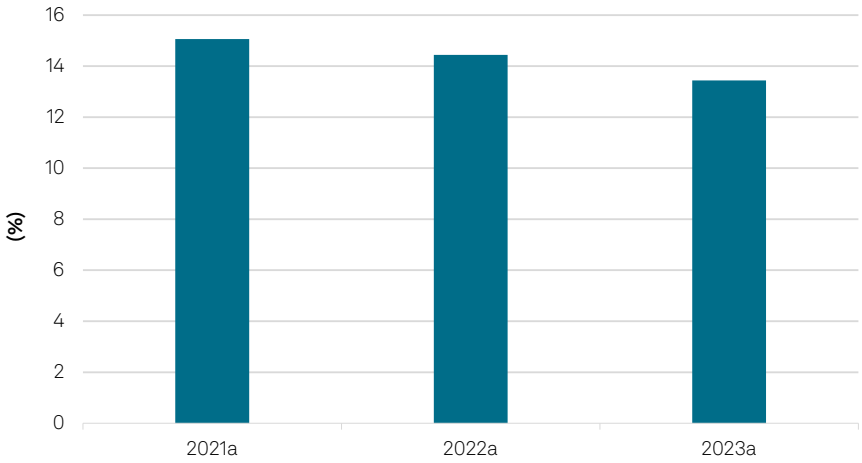
We expect securitization will remain an effective tool that the industry will continue to use. Our base case includes increasing severe natural disasters and weather events as well as continued efforts to decarbonize the energy sector, which sometimes requires securitization to fully recover under-depreciated retiring fossil-fuel generating plants.

Credit metrics and financial policy

We expect rising capital spending and increasing cash flow deficits that are not sufficiently funded in a credit-supportive manner will continue to pressure the industry's financial performance. Its average funds from operations (FFO) to debt was about 15% in 2021 and has gradually fallen to about 13.5%, primarily reflecting rising leverage (see chart 20). Given our expectations for continued increasing capital spending over the next decade, we expect financial performance and credit quality will continue to be pressured.

Chart 20

North American regulated utilities' average FFO to debt



a—Actual. Source: S&P Global Ratings.

Key risks or opportunities around the baseline

1. Wildfire mitigation efforts.

Wildfire risk mitigation, while clearly a credit positive, may not fully address the threats associated with extreme weather events.

2. Data centers and sales growth.

Data center electricity demand will likely boost revenues at North American investor-owned regulated utilities and provide modest support for the industry's credit quality.

3. Managing the customer bill.

The average electric customer bill is about 2% of U.S. median household income, which represents good value for customers relative to other typical household bills. Preserving this value is critical for the industry to maintain credit quality.

Wildfire risk has expanded. Recent events in the Northeast U.S. lead us to believe wildfire risk has spread and now potentially affects nearly every utility across North America. (About 15 years ago, it was primarily limited to just Southern California.)

Wildfire risk is highly negative for credit quality. The scale of potential liabilities, unpredictable nature of exposures, and frequency of events have materially increased wildfire risk for many utility stakeholders. From a credit standpoint, litigation risk is more problematic than risk of damage to infrastructure because it is difficult to predict or quantify and is so far without sufficient mitigation or containment. Also, wildfire-related litigation payments are typically not recoverable in rates or through other regulatory mechanisms, making them more problematic than physical risk.

Additional wildfire risks to credit quality include:

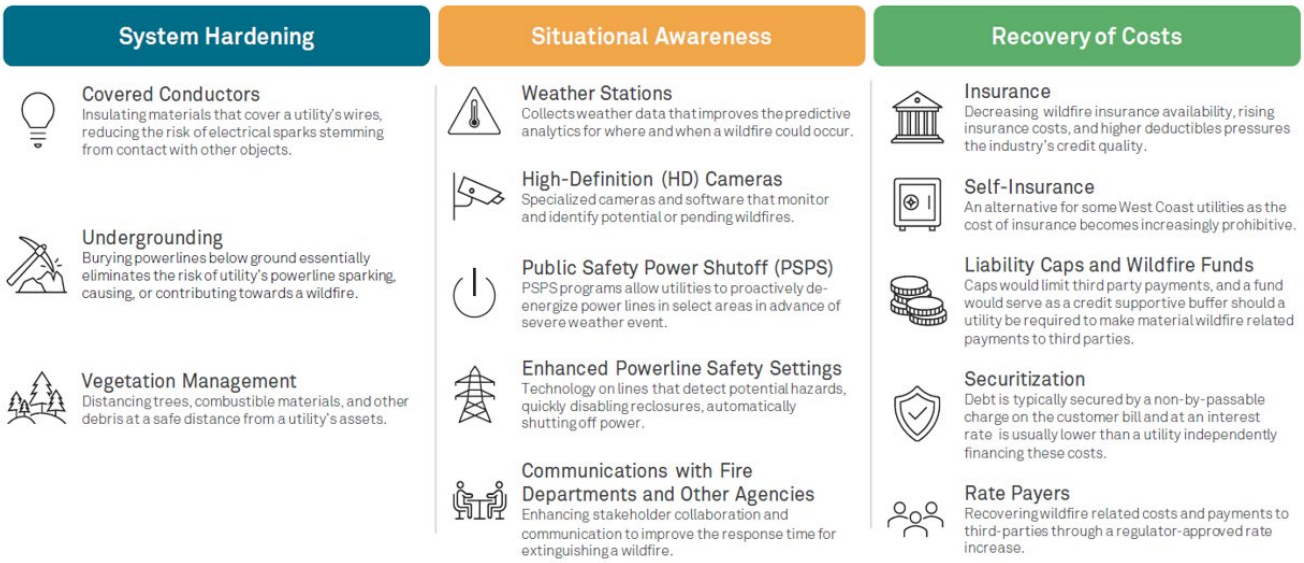
- Insurance is becoming more expensive and less available.
- It only requires a relatively small percentage of damaged or destroyed structures from a wildfire to have a material negative effect on a utility's credit quality.

- The utility industry's relatively high leveraged balance sheets and modest authorized ROEs are not a backstop for wildfire risk.
- Utilities that are impacted by a catastrophic wildfire and material third-party claims typically cannot implement other strategic initiatives.

Mitigation strategies. We expect the industry will develop plans that reduce damages, minimize litigation risk, and expand capabilities for cost recovery from wildfires. We believe the industry will be able to implement much of these strategies over the nearer term because most are not predicated on the development of new technologies or products. That said, because the industry operates in many different service territories and topographies, we expect each utility's mitigation plan will be customized to its unique exposure. Chart 21 represents an array of wildfire mitigation strategies that either have or are being implemented by many utilities across North America.

Chart 21

North American regulated utilities' wildfire mitigation efforts



Source: S&P Global Ratings.

Data centers will likely deliver a return to electricity sales growth. We expect electricity sales will increase at a CAGR of about 1.1%. This reflects our view that systematic and careful planning across the investor-owned utility sector will likely limit its realistic capability to grow at a substantially faster pace. In general, the expansion of utility infrastructure assets is a long-term planning process that requires permitting, siting, and regulatory approvals.

However, even a 1% CAGR for electricity sales will likely prove transformative for the utility industry, which has experienced flat sales growth over the past two decades. In particular, the growing number of data centers will allow the industry to spread its fixed costs over a wider base. We anticipate this will provide some cushion for the industry to effectively manage regulatory risk and maintain credit quality without necessarily requiring that every rate case order is highly supportive of credit quality.

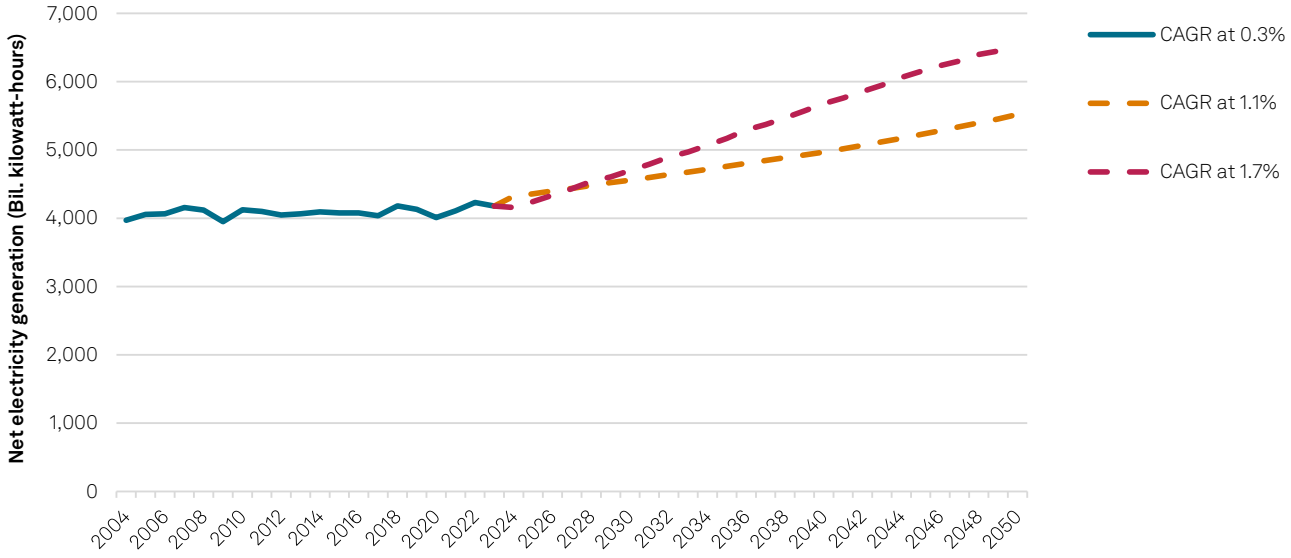
We also expect electric utilities' sales CAGR will be maintained over the longer term (see chart 22), which will support the industry's long-term credit quality. We expect growth in data center numbers will support most of the industry's growth through 2030. In the following decade,

increased onshoring of manufacturing and wider spread adoption of electric vehicles will also support growth.

Chart 22

Growth will be transformative for utilities used to stagnation

Electricity demand: U.S. regulated electric utilities



Data as of June 2024. CAGR—Compound annual growth rate. Sources: U.S. Energy Information Administration (historical and 1.1% CAGR) and S&P Global Commodity Insights (1.7% CAGR).

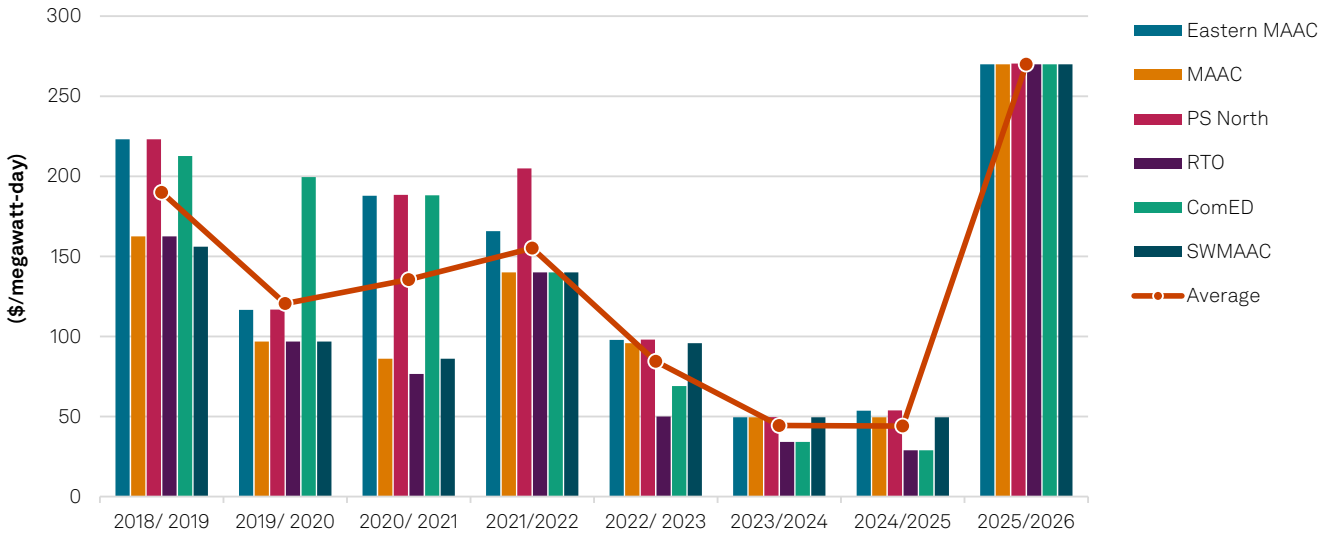
Data center credit risks. The industry must structure rates and contracts to ensure that the new data center customers are paying their share of electricity costs. Meeting the demands of relatively few, but very large, data center customers will require significant capital spending and infrastructure investments. If utilities assign a significant portion of data center-related infrastructure costs to existing residential customers, customer bills would increase. This, in turn, pressures regulators to limit rate case increases, which can negatively affect the industry's ability to effectively manage regulatory risk.

Therefore, we expect the increased capital spending needed to accommodate data center growth will be primarily recovered from data center customers over decades. Such a plan comes with risks. For example, a technological breakthrough that reduces or eliminates the need for data centers could shift the recovery of these long-term infrastructure investments onto residential customers.

Capacity prices. Pennsylvania-New Jersey-Maryland (PJM) Interconnection capacity prices materially increased during its latest capacity auction (see chart 23). These higher prices are directly passed onto customers, significantly increasing the electric utility bill. If these higher prices persist, it will likely result in higher customer complaints, pressuring regulators to limit increases to other areas of the customer bill that could potentially pressure a utility’s ability to effectively manage regulatory risk.

Chart 23

PJM capacity auction results



Source: PJM website.

U.S. Environmental Protection Agency (EPA). In 2024 the EPA released final rules aimed at reducing pollution from fossil fuel-fired power plants, which included carbon pollution standards and effluent limitation guidelines and standards for coal-fired power plants. These rules would have increased costs for utilities, specifically regarding the requirement to install carbon capture and sequestration or storage technology on coal-fired power plants intending to operate beyond 2039.

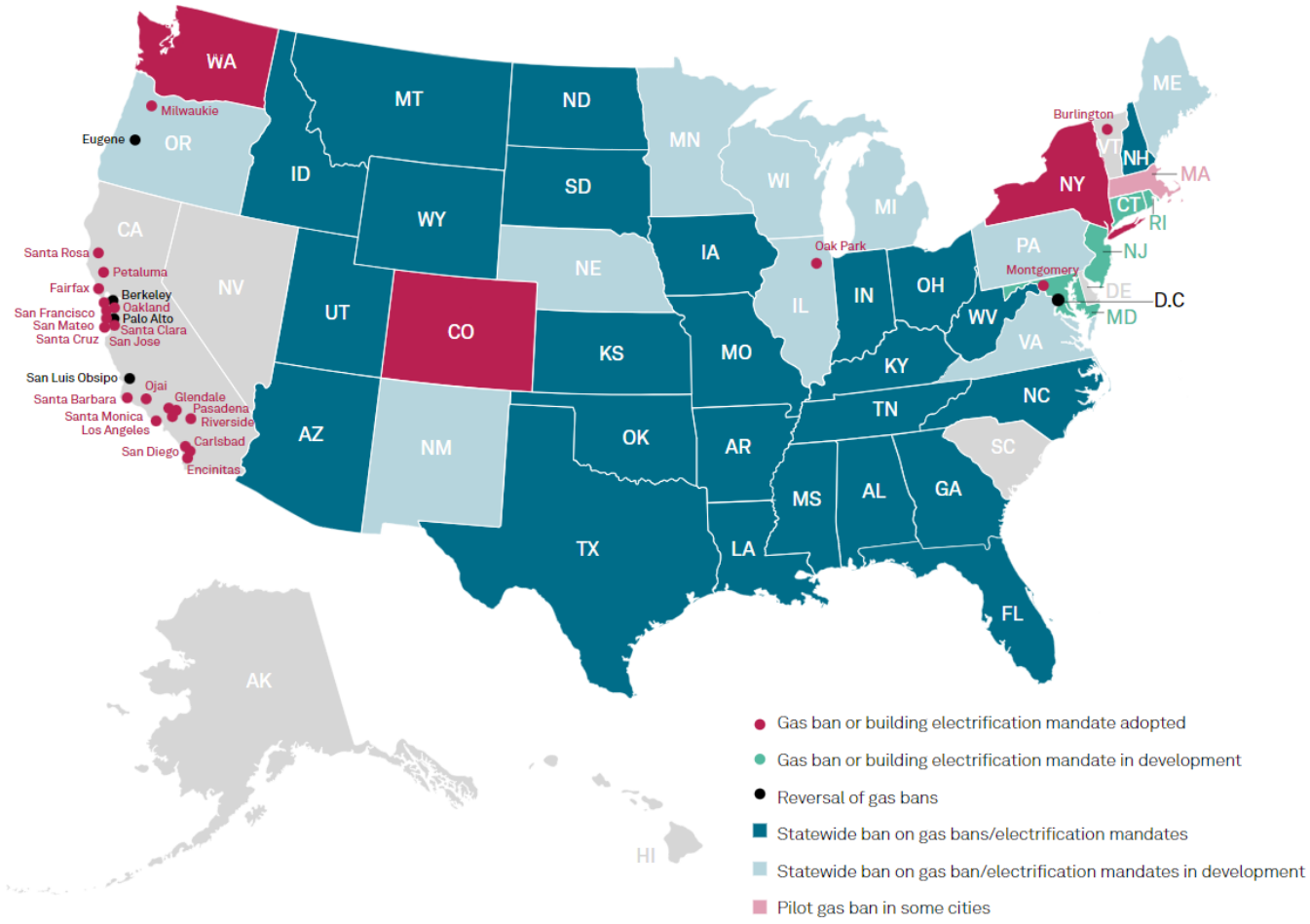
However, we note that the incoming U.S. presidential administration and Republican majority in congress could modify or eliminate these rules. We will monitor executive, legislative, or legal actions that could impact the industry's credit quality.

Full electrification. We expect the longer-term credit quality for some natural gas local distribution companies (LDC) will become increasingly challenging, especially for utilities that operate in warmer climates or whose cities or states have banned new gas connections, severely limiting the growth of natural gas LDCs (see chart 24). We expect this trend will also gradually persist through the passage of local city and town building codes that limit carbon and other emissions.

Offsetting some of this risk is that a majority of states have imposed a ban on the ban of new gas connections. Furthermore, gas LDCs are attempting to reduce their environmental risks by decreasing their carbon footprint through investing in renewable natural gas, blending hydrogen, and initiating various hydrogen infrastructure projects.

Chart 24

Gas bans and electrification mandates



Data as of April 26, 2024. *Municipalities shown on map are a subset of municipalities in the U.S. that have gas ban policies or electric reach codes in place. §Colorado and Burlington mandates target emissions requirements set out in respective laws or regulations. Source: S&P Global Commodity Insights.

Cybersecurity. While cybersecurity breaches against infrastructure assets have been relatively low, we believe the threat of cyberattacks remains high. The 2024 cybersecurity breach against American Water Works Co. Inc. underscores the risks. But the sector has heavily invested to limit this risk. We believe the sector's ongoing vigilance in this area is critical to maintaining credit quality.

Related Research

- Wildfire-Exposed U.S. Investor-Owned Utilities Face Increasing Credit Risks Without Comprehensive Solutions, Nov. 6, 2024
- Data Centers: Rapid Growth Creates Opportunities And Issues, Oct. 30, 2024
- Evolving Risks In North American Corporate Ratings: Climate Change, Oct. 29, 2024
- Data Centers: Welcome Electricity Growth Will Fall Short Of U.S. Data Center Demand, Oct. 22, 2024
- Energy Transition: U.S. Investor-Owned Regulated Electric Utilities Face Hurdles With The EPA's Finalized Rules For Fossil-Fueled Power Plants, Oct. 17, 2024
- North American Utility Regulatory Jurisdictions Update: Some Notable Developments, Sept. 24, 2024

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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Generating Unit Periodic Outages
May 1, 2026 Through April 30, 2027

Case No.: U-21870
Exhibit No.: A-41 (RTB-1)
Page: 1 of 1
Witness: RTBlumenstock
Date: June 2025

MAJOR OUTAGES: FOSSIL GENERATION AND LUDINGTON

Line No.	(a) Unit	(b) Planned Days in test year	(c) Start	(d) Stop
1	Covert 3	59	3/15/2026	5/13/2026
2	Covert 1	59	9/1/2026	10/30/2026
3	Ludington 3	274	9/2/2026	6/3/2027
4	Ludington 6	49	9/8/2026	10/27/2026
5	Ludington 5	42	9/10/2026	10/22/2026
6	Ludington 4	683	10/19/2026	9/1/2028
7	Karn 3	30	10/12/2026	11/10/2026
8	Karn 4	30	10/12/2026	11/10/2026
9	Karn 3	29	3/22/2027	4/19/2027
10	Karn 4	29	3/22/2027	4/19/2027

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Generating Unit Availability Projections
May 1, 2026 Through April 30, 2027

Case No.: U-21870
Exhibit No.: A-42 (RTB-2)
Page: 1 of 1
Witness: RTBlumenstock
Date: June 2025

Line No.	(a) Plant	(b) Actual ROR 2020-2024	(c) Projected ROR	(d) Periodic Factor	(e) Projected Availability	(f) Actual NEV 2020-2024
1	Karn 3	38.70%	18.00%	15.69%	69.13%	-$5,693,158
2	Karn 4	24.76%	18.00%	11.01%	72.97%	-$11,209,496
3	Ludington 1	5.06%	3.50%	14.98%	82.05%	$25,377,430
4	Ludington 2	4.94%	3.50%	16.49%	80.59%	$4,496,863
5	Ludington 3	6.81%	3.50%	81.59%	17.77%	$7,915,021
6	Ludington 4	7.75%	3.50%	100.00%	0.00%	$1,546,713
7	Ludington 5	7.34%	3.50%	15.77%	81.28%	$2,597,848
8	Ludington 6	4.97%	3.50%	12.94%	84.01%	$32,440,361
9	Hydros	9.48%	5.60%	5.32%	89.38%	$44,905,317
10	Zeeland CC	7.48%	4.00%	8.54%	87.80%	$212,622,574
11	Zeeland 1A	3.89%	4.00%	6.27%	89.98%	$23,489,877
12	Zeeland 1B	4.45%	4.00%	6.27%	89.98%	$26,619,605
13	Jackson	8.22%	4.50%	3.57%	92.09%	$179,394,987
14	Covert 1 (3)	4.09%	7.00%	20.30%	74.12%	$48,357,129
15	Covert 2 (3)	6.25%	7.00%	5.87%	87.54%	$39,786,258
16	Covert 3 (3)	6.08%	7.00%	8.81%	84.80%	$43,506,152
17	Cross Winds EP					$119,073,933
18	Lake Winds EP					$43,165,858
19	Gratiot Farms Wind(1)					$44,384,560
20	Crescent Wind(1)					$44,829,098
21	Heartland (2)					$9,604,705
22	Solar Gardens					$1,339,535

(1) Reflects NEV for 2022-2024 only.
(2) Reflects NEV for 2023-2024 only.
(3) Reflects NEV for 2023-2024 only.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of the Generation O&M Expense
For the Years 2024 through April 2027
($000's)

Case No.: U-21870
Exhibit No.: A-43 (RTB-4)
Page: 1 of 3
Witness: RTBlumenstock
Date: June 2025

GENERATION OPERATION AND MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2024	(c) Projected Bridge Period 16 Months Ending 04/30/2026	(d) Projected Test Year 12 Months Ending 04/30/2027
1	**BASE O&M**	$ 91,056	$ 105,324	$ 68,705
2	**ADJUSTED O&M**			
3	Environmental Operations	$ 8,539	$ 5,110	$ 2,045
4	Major Maintenance	$ 28,844	$ 40,012	$ 32,982
5	Retention & Separation	$ 8,626	$ 5,182	$ -
6	**TOTAL O&M**	**128,438**	**150,445**	**103,732**

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-43 (RTB-4)
Page: 2 of 3
Witness: RTBlumenstock
Date: June 2025

Consumers Energy Company
Summary of the Generation O&M Expense
For the Years 2024 through April 2027
($000's)

Line No.	Description	2024 Actual	Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 12 Mos Ending Dec 31, 2026	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	Merit & Inflation 4 Mos Ending 4/30/2027	Other Adjustments	Projected O&M 12 Mos Ending 4/30/2027
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
	Total O&M	**128,438**	**128,438**	**2,697**	**131,136**	**3,147**	**134,283**	**1,074**	**-31,625**	**103,732**
1	Labor	74,738	74,738	1,570	76,308	1,831	78,139	625	-18,402	60,362
2	Material	5,597	5,597	118	5,715	137	5,852	47	-1,378	4,520
3	Contractor	23,210	23,210	487	23,697	569	24,266	194	-5,715	18,745
4	Non-Labor Overheads	100	100	2	103	2	105	1	-25	81
5	Non-Labor Other	24,793	24,793	521	25,314	608	25,921	207	-6,105	20,024

Notes

		2025	2026	2027
*	Annual merit increase			
	Annual merit increase	2.10%	2.4%	2.4%
	Number of months in the period	12	12	4
	Pro-rated merit increase	2.10%	2.4%	0.8%
	Annual inflation rates per WP-JCA-51			
	Annual inflation rates	2.10%	2.4%	2.4%
	Number of months in the period	12	12	4
	Pro-rated inflation rate	2.10%	2.4%	0.8%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of the Generation O&M Expense
For the Years 2024 through April 2027
($000's)

Case No.: U-21870
Exhibit No.: A-43 (RTB-4)
Page: 3 of 3
Witness: RTBlumenstock
Date: June 2025

GENERATION MAJOR MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2024	(c) Projected Bridge Period 16 Months Ending 04/30/2026	(d) Projected Test Year 12 Months Ending 04/30/2027
	Major Maintenance			
1	Campbell 1&2	$ 903	$ 483	$ -
2	Campbell 3	$ 591	$ 709	$ 279
3	Karn 1&2	$ -	$ -	$ -
4	Karn 3&4	$ 2,027	$ 2,732	$ 1,824
5	Classic 7	$ -	$ 291	$ 218
6	Zeeland Generating Station	$ 4,954	$ 7,063	$ 5,419
7	Jackson Generating Station	$ 5,669	$ 5,712	$ 4,112
8	Covert Generating Stations	$ 6,553	$ 8,681	$ 7,771
9	Ludington	$ 3,314	$ 5,842	$ 4,708
10	Hydros	$ 4,832	$ 7,937	$ 8,374
11	Battery	$ -	$ 412	$ 126
12	Admin & Other	$ -	$ 150	$ 150
13	**TOTAL Major Maintenance**	**$ 28,844**	**$ 40,012**	**$ 32,982**

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Consumers Energy Count on Us®

Concept Approval

Zeeland Phase 1 Gas Turbine upgrades.

Date: 2/22/2024

Prepared by: Paul Ohep

Figure 1. Zeeland Generating station.

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Executive Summary

The Zeeland Generating Station, an integral component of Consumers Energy's generation portfolio, is poised for significant technological enhancements. Scheduled Major Inspection outages in 2025 for Phase 1 turbines provide a strategic opportunity for substantial improvements through the implementation of Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies. These upgrades aim to boost turbine performance, efficiency, and operational flexibility, aligning with the shift towards a more renewable-centric energy mix.

Technological Enhancements and Economic Justification:

- **Advanced Gas Path (AGP):** AGP technology will replace existing turbine components with high-performance alternatives, aiming to increase output and improve heat rate efficiency without compromising reliability.
- **Axial Fuel Staging (AFS):** Complementing AGP, AFS enhances output turndown capability, vital for flexible operation amidst fluctuating renewable energy inputs. This technology allows the turbines to operate at lower loads while maintaining emissions compliance, ensuring Zeeland Phase 1 turbines can adeptly support the transition to renewable energy.

Alternatives Considered:

1. **Do Nothing:** Foregoing the upgrades results in missed potential savings of $133M over the period from 2025 to 2040, risking the station's competitiveness and operational flexibility in a rapidly evolving market.
2. **AGP Only:** This upgrade, with an initial capital investment of $44.4M, leverages AGP technology to enhance turbine efficiency and performance, yielding estimated customer savings of $57M over fifteen years. The AGP upgrade alone is a step towards modernization but doesn't fully capture the operational flexibility provided by AFS.
3. **AFS Only:** Focusing solely on AFS technology, this option involves a $22M investment but results in a marginal loss of $1.7M over fifteen years, primarily due to the absence of capacity revenue increases and insufficient energy revenue to cover the investment and operational costs.
4. **AGP and AFS Combined:** A comprehensive approach with a $49.1M investment in both AGP and AFS technologies is projected to offer the most significant benefits. This option not only enhances turbine performance and efficiency but also ensures operational flexibility to manage the variability of renewable energy sources. The combined upgrade is expected to yield considerable savings of an estimated $132.8M, factoring in improved maintenance cycles, reduced start requirements, and operational cost savings.

Financial Summary

Estimated investment: $49,100,000

Proposed Start Implementation Year and duration

Start 2024 and complete in 2025.

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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. 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 2025, the Zeeland Phase 1 site is scheduled for Major Inspection outages, presenting an opportune moment to undertake substantial improvements in both Phase 1 gas turbines. This project is centered around the implementation of upgraded replacement parts that significantly enhance performance and reliability.

Advanced Gas Path (AGP): This improvement technology aims to elevate the output and efficiency of the turbines. AGP involves replacing existing turbine and combustion parts with high-performance, technologically advanced counterparts. The enhancement is expected to deliver notable improvements in output and heat rate efficiency, maintaining the same level of reliability.

Axial Fuel Staging (AFS): In conjunction with AGP, AFS is another pivotal 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 1 simple cycle gas turbines maintain operational flexibility to support this transition, accommodating the variability inherent in renewable energy sources.

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Alternative Solutions/Alternatives Considered

1. Do Nothing – Cost: $133M (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:** $133M (Unrealized Savings)
- **Impact:** Choosing this option results in forgoing the potential savings that could be achieved through Alternatives #2 and #3.

Detailed Analysis

- **Unrealized Potential Savings:** If neither Alternative #2 (AGP installation) nor Alternative #3 (AGP & AFS installation) is selected, Zeeland Phase 1 stands to lose potential savings $133M 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 1 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 $44,400,000

This alternative entails the installation of an Advanced Gas Path (AGP) in Zeeland Phase 1's gas turbines, a significant upgrade to enhance performance and efficiency.

Financial Overview:

- **Cost:** Total customer cost of $57M 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 $110.5M through 2040.
  - The projected incremental capacity revenue is projected to be $128.3M through 2040.
- **Impact:** The AGP only option will provide a favorable NPV gain of $90,835,000 through 2040. This is based on an Aurora internal economic model performed in February of 2024.

Table 1 below summarizes the incremental revenues and costs for the AGP only option.

NPV Results AGP only

	Zeeland 1A	Zeeland 1B	Entire station
Current Nameplate Capacity (MW)	180	180	
Upgraded Capacity (MW)	205	205	
NPV, Incremental Energy Revenue AGP Only (K$)	($55,182)	($55,293)	($110,476)
NPV, Incremental Capacity Revenue AGP Only (K$)	($64,123)	($64,123)	($128,247)
NPV, Incremental Operating Costs AGP Only (K$)	$45,459	$45,413	$110,859
NPV, Investment customer cost - AGP Only (K$)	$57,015		
NPV, Total Value of AGP Only (K$)	**$90,835 (savings)**		

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:

Output Improvement

- **Improvement:** +25MW at Full/Base Load, based on GE's quotes showing approximately 22MW improvement in warmer months and 28MW in cooler months.

Heat Rate Improvement

- **Improvement:** -2.8% Efficiency Improvement across Load Range.

Utilization Factor Improvement

- **Justification:** Assumed 20% Utilization Increase based on a comparison of Zeeland's GT 1B hours to CMS's DIG (Deerborn industrial generation) simple cycle GT hours.

- 20% is likely conservative as the DIG 7FA.04 turbine has been more valuable to the market than ZGS's GT1B for the last three years (ZGS GT1A not considered due to Electrical Transformer failure in 2021-2022)

Parts Longevity Improvement

- **Improvement:** One Hot gas path inspection (HGPI) Deleted from Maintenance Cycle, increasing the interval from 900 starts to 1350 starts. This eliminates an entire HGPI from 2025 to 2040.

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 2023 base by 3% per year with an added 10% contingency.
- 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 1 turbines. The project is anticipated to result in significant Net Present Value (NPV) savings of $57 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.Opting for the AGP-only upgrade thus emerges as a financially viable decision. With a total investment of $57M, this option not only enhances the turbines' efficiency and competitiveness but also secures substantial savings of $57M in NPV over the fifteen-year period.

3. Install AFS only – initial investment $22,000,000

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.

Financial Overview:
The investment for the AFS-only upgrade is quantified at $22M, encompassing the costs associated with implementing AFS technology across both Zeeland 1A and 1B units.

Detailed financials

- **Cost:** Total customer cost of $28.3M 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 $118.3M through 2040.
- **Impact:** The AFS only option will provide a NPV loss of $1.7M through 2040. This is based on an Aurora internal economic model performed in February of 2024.

Table 2 below summarizes the incremental revenues and costs for the AFS only option.

NPV Results AFS only

	Zeeland 1A	Zeeland 1B	Entire station
Current Nameplate Capacity (MW)	180	180	
Upgraded Capacity (MW)	205	205	
NPV, Incremental Energy Revenue AFS Only (K$)	($58,435)	($59,869)	($118,304)
NPV, Incremental Capacity Revenue AFS Only (K$)	$0	$0	$0
NPV, Incremental Operating Costs AFS Only (K$)	$45,377	$46,369	$91,746
NPV, Investment Customer cost - AFS Only (K$)	$28,251		
NPV, Total Value of AFS Only (K$)	**$1,692 (loss)**		

Table 2. Revenue and costs table for AFS only option

Operational and Economic Implications: The AFS-only upgrade offers notable operational benefits, such as enhanced emissions control, yet 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. Consequently, a projected financial loss of $1,692K over a fifteen-year span underscores the economic limitations of implementing

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the AFS technology by itself, devoid of the synergistic advantages provided by AGP upgrades.
Crucially, the AFS-only strategy misses out on the considerable operational improvements associated with AGP enhancements, including a capacity boost of 25MW per unit and a heat rate improvement of 2.7%.

4. Install AGP and AFS – initial investment cost - $49.1M

This alternative proposes a comprehensive upgrade to the Zeeland Phase 1 gas turbines by installing both Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies.

Financial Overview:

- **Cost:** Total customer cost of $63,051,000 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 savings of an estimated $132,753M from 2025 through 2040 from the upgrade alone plus an additional $1.75M from reduced LTSA fees. This is based on an Aurora internal economic model performed in February of 2024.

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 install Economic benefits breakdown and assumptions:

- **Maintenance Cycle Interval Improvement (2025-2040):**
  - Major Inspection / Rotor Replacement Outage Avoided from Maintenance Cycle.
  - Starts Reduction**:**
    - Estimated at 25% (from 200 starts per year to 150 starts per year)
    - Starts reduction pushes the Major Inspection / Rotor Replacement Outage out to 2041.
- **Reduced LTSA Fees ($1.75M in NPV savings over 15 years):** $185k/year. 25% less starts changes LTSA Fees structure yielding savings.

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Table 3 below shows a summary of the NPV incremental costs and revenues for this option.

Net Present Value Results	Zeeland 1A	Zeeland 1B
Current Nameplate Capacity (MW)	180	180
Upgraded Capacity (MW)	205	205
NPV, Incremental Energy Revenue Full Upgrade (K$)	($152,118)	($155,119)
NPV, Incremental Capacity Revenue Full Upgrade (K$)	($64,123)	($64,123)
NPV, Incremental Operating Costs Full Upgrade (K$)	$118,839	$120,841
NPV, Investment customer cost, Full Upgrade (K$)	$63,051	
NPV, LTSA Savings (K$)	($1,748)	
NPV, Total Value of Full Upgrade (K$)	($132,753)	

Table 3. Revenue and costs table for AGP and AFS option

In summary, the comprehensive upgrade of Zeeland Phase 1 with Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies is a significant undertaking with a total customer cost of $63.1 million (in today's dollars) and an initial investment of $49M. This cost includes all components, work scope, additional loadings, and a major upgrade of the turbine model. Despite the sizeable initial expenditure, the upgrade is projected to yield substantial customer savings of an estimated $132.8 million. These savings are expected to arise from improved maintenance cycles, a reduction in the number of starts, enhanced gas supply efficiency, and reduced Long-Term Service Agreement (LTSA) fees.

Other benefits for Options 2, 3 and 4

- **Minimum Output Improvement:** Improves Minimum Output (turndown) down to 80 MW with AGP or 50 MW with AFS.
- **Demand Response Flexibility:** Enhanced flexibility, especially with AFS, due to faster ramp rates and potential for providing spinning reserve.
- **Long-term Maintenance Planning:**
  - Maintenance interval every 1350 starts for AGP or 1250 starts for AFS allows the 10% grace on the maintenance interval from GE to go from 90 starts to 135 or 125 starts.
  - Extended maintenance intervals allow greater flexibility in planning.
  - 45 or 35 more grace starts to work with to ensure outages longer than 30 days span two MISO seasons if needed for the Major/Rotors outage.
  - AGP/AFS implementation opens the opportunity for GE LTSA contract negotiation to reduce contract design and costs.

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Recommended Alternative: #4 – Install AGP and AFS – initial investment - $49.1M

The scheduled Major Inspection outages in 2025 for the Phase 1 gas turbines at Zeeland Generating Station present an ideal moment for substantial technological advancements. This project proposes the integration of Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies during these outages, aimed at boosting turbine performance and operational flexibility.

Economic and Operational Benefits:

1. **Increased Revenue and Efficiency:**
    - AGP and AFS upgrades are poised to enhance output, heat rate efficiency, and utilization factor.
    - The project contributes to future goals of rate reduction by enabling more efficient and cost-effective operations.
    - Reduction in Long Term Service Agreement (LTSA) fees adds to the cost savings.
2. **Significant Cost Savings:**
    - The implementation of AGP and AFS is projected to realize an estimated $132,753,000 in savings from 2025 through 2040, offering substantial financial returns over the mid to long term.
3. **Market Competitive Advantage:**
    - The integration of AGP and AFS ensures that Zeeland Phase 1 remains a competitive and adaptable player among gas turbine facilities in the MISO system.
    - The adoption of AGP is already a trend in the industry, with the uptake of AFS expected to follow.
4. **Operational Flexibility Benefits:**
    - AFS technology enables a wider range of emissions-compliant operation, enhancing flexibility from low-load to full baseload operation.
    - The improved operating profiles lead to fewer starts and more operating hours, reducing annual starts and cumulative start-up emissions.
5. **Long-term Maintenance and Contractual Benefits:**
    - AGP and AFS contribute to extended maintenance intervals, offering more flexibility in long-term outage planning.
    - The implementation paves the way for potential renegotiations of the GE LTSA contract, which could reduce associated costs.

The integration of AGP and AFS technologies at Zeeland Generating Station's Phase 1 turbines 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 evolving energy portfolio. This investment is justified by the considerable potential savings, improved efficiency, and the strategic positioning of Zeeland Phase 1 for future energy demands.

Scope of Work

Scope of Work Activities for Erickson's and GE's Major Inspection at Zeeland Phase 1:

1. **Erickson's Responsibilities**:
    - Provide cranes and lifting services as part of the already scheduled and budgeted GE LTSA Major Inspection work.
2. **GE Parts/Software Scope of Supply**:
    - **Advanced Gas Path (AGP)** Components:
        - Stage 1, 2, and 3 Nozzle and Bucket Kits.
        - Stage 1, 2, and 3 Shroud Kits.
        - Modifications for cooling and sealing air orifices.
        - Provision of installation and modification documents.
        - OpFlex Enhanced Transient Stability Model Based Controls platform.
        - Firing temperature increase and updated Model Based Control (MBC) software.
        - Length 1AO, 2FO, 2AO wheelspace thermocouples.
    - **DLN 2.6+** Components:
        - Major Disassembly Tool Kit.
        - Gas-Only Fuel Nozzle Assembly and Emergency Stop Valve.
        - Combustion Chamber, Transition Piece, and Combustion Liner Arrangements.
        - Aft Combustion Case, Combustion Tuning Piping, and Spark Plug Assembly.
    - **Gas Control Valves (GCVs)/Stop Ratio Valve (SRV)**:
        - High Recovery GCVs.
        - SRV and supporting components.
        - Modifications to Gas Turbine Controls.
3. **Axial Fuel Staging (AFS)** Components:

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- AFS injectors and sealing.
- Fuel delivery tubing and valving.
- Additional 5th fuel circuit and manifold for AFS.
- Manway covers.

4. **GE Work Scope**:
    - Removal of old turbine parts.
    - Installation of new AGP and AFS components.
    - Modifications to existing parts.
    - Revision of control curves and constants.

Funding and Timing

- No funding has been previously committed for this project.
- An Scheduled outage is required for this project.
- Desired implementation year: 2024
- 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 1 to a year beyond the recommended 2024 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

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Conceptual Estimate

Year	Loaded Cost	Description
2024	**$12,275,000**	25% Payment for Lump Sum
2025	**$36,825,000**	75% Payment for Lump Sum

Total Cost: $49,100,000

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.

This investment **has not** been included in the 2023 electric rate case. A strategic decision was taken to reallocate capital from another project, which, upon reassessment, was found to offer less value to our customers compared to the proposed initiative. This reallocation is based on a comprehensive evaluation of project priorities and the potential impact on service and safety. It was concluded that redirecting funds to this new project represents the most prudent and beneficial approach, ensuring that we continue to deliver maximum value and reliability to our customers without compromising the safety or integrity of existing infrastructure.

Key terms to note about electric rate case:

1. Inclusion in Rate Case: The rate case typically encompasses the Capital component of projects planned for the bridge year (the year of filing, which is 2023 in this scenario) and the test year (usually the following year, in this case, 2024).

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Approvals

Title	Approver Name	Date
Generation Planning Manager John D Slinkard	DocuSigned by: John D Slinkard D640D95639854BE...	2/22/2024 | 2:19 PM EST
Director of Generation Asset Strategy Scott Hugo	DocuSigned by: Scott Hugo 31EC7A87F8F34C6...	2/22/2024 | 1:34 PM EST
Exec Director of Electric Supply Engineering Richard T. Blumenstock	DocuSigned by: Richard T. Blumenstock C3E2F0B9920949B...	2/22/2024 | 2:48 PM EST
VP of Electric Supply Srikanth Maddipati	DocuSigned by: 67DA622787D2488...	2/22/2024 | 3:57 PM EST

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Zeeland CT Capacity Increase Analysis

2/21/2024

The below analysis considers three scenarios:
AGP Only: models an increase of 25 MW at each Zeeland station and a 2.7% heat rate efficiency incre
Full Upgrade: AGP Scenario + an adjustment to the minimum capacity of the resource of 45 MW
AFS Only: models only a minimum capacity of 45 MW

Note that the analysis was completed using Aurora simulations and that there are a couple years in v
This projection is unlikely, as the unit can be expected to run, at least for reliability purposes. Howev

Values are represented as negative (reduction to customer cost)
Expenses are represented as positive (customer expense)

Net Present Value Results

	Zeeland 1A	Zeeland 1B
Current Nameplate Capacity (MW)	180	180
Upgraded Capacity (MW)	205	205
NPV, Incremental Energy Revenue AGP Only (K$)	($55,182)	($55,293)
NPV, Incremental Energy Revenue Full Upgrade (K$)	($152,118)	($155,119)
NPV, Incremental Energy Revenue AFS Only (K$)	($58,435)	($59,869)
NPV, Incremental Capacity Revenue AGP Only (K$)	($64,123)	($64,123)
NPV, Incremental Capacity Revenue Full Upgrade (K$)	($64,123)	($64,123)
NPV, Incremental Capacity Revenue AFS Only (K$)	$0	$0
NPV, Incremental Operating Costs AGP Only (K$)	$45,459	$45,413
NPV, Incremental Operating Costs Full Upgrade (K$)	$118,839	$120,841
NPV, Incremental Operating Costs AFS Only (K$)	$45,377	$46,369
NPV, Investment Rev Req AGP Only (K$)	$57,015	
NPV, Investment Full Upgrade (K$)	$63,051	
NPV, Investment AFS Only (K$)	$28,251	
NPV, Total Value of AGP Only (K$)	**($90,835)**	
NPV, Total Value of Full Upgrade (K$)	**($132,753)**	
NPV, AFS Value of AFS Only (K$)	**$1,692**	

Notes:
Capacity value is assumed at 75% of the cost of new entry
Capacity accreditation is estimated at 90% for all seasons
Energy price projections were developed based on the 2024 0+12 commodity price outlook

Annual Detailed Results

Incremental Energy Revenue (K$)

	Zeeland 1A	
	AGP Only	Full Upgrade
2025	($8,696)	($24,630)
2026	($6,121)	($17,020)
2027	($6,981)	($19,174)

2028	($6,797)	($18,711)
2029	($7,145)	($16,699)
2030	($10,543)	($24,990)
2031	($9,612)	($26,252)
2032	($6,084)	($21,300)
2033	($4,936)	($18,351)
2034	($6,366)	($18,326)
2035	($1,896)	($6,770)
2036	($1,744)	($3,076)
2037	($1,169)	($2,860)
2038	($1,908)	($2,818)
2039	($988)	($2,333)
2040	$0	$0

Incremental Operating Costs (K$)

Zeeland 1A

	AGP Only	Full Upgrade
2025	$7,188	$19,302
2026	$5,059	$13,351
2027	$5,887	$14,701
2028	$5,650	$14,555
2029	$5,523	$12,288
2030	$8,586	$18,805
2031	$8,032	$20,778
2032	$5,123	$17,178
2033	$3,955	$14,652
2034	$5,487	$14,838
2035	$1,600	$5,714
2036	$1,494	$2,494
2037	$848	$2,175
2038	$1,518	$2,251
2039	$714	$1,917
2040	$0	$0

Incremental Capacity Revenue (K$)

Zeeland 1A and 1B

	AGP Only	Full Upgrade
2025	($2,988)	($2,988)
2026	($3,054)	($3,054)
2027	($3,121)	($3,121)
2028	($3,189)	($3,189)
2029	($3,260)	($3,260)
2030	($3,331)	($3,331)
2031	($3,405)	($3,405)
2032	($3,479)	($3,479)
2033	($3,556)	($3,556)
2034	($3,634)	($3,634)
2035	($3,714)	($3,714)
2036	($3,796)	($3,796)

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2037	($3,879)	($3,879)
2038	($32,511)	($32,511)
2039	($33,226)	($33,226)
2040	($33,957)	($33,957)

Annual Revenue Requirement (K$)

	AGP Investment	$44,400
2025	$6,036	
2026	$6,036	
2027	$6,036	
2028	$6,036	
2029	$6,036	
2030	$6,036	
2031	$6,036	
2032	$6,036	
2033	$6,036	
2034	$6,036	
2035	$6,036	
2036	$6,036	
2037	$6,036	
2038	$6,036	
2039	$6,036	
2040	$6,036	
NPV	**$57,015**	

Fixed Charge Rate	13.59%

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vhich *no generation* is predicted from these resources.
er, this is a strictly economic study.

Zeeland 1B

AFS Only		AGP Only	Full Upgrade
($10,629)	2025	($8,421)	($25,061)
($5,611)	2026	($6,160)	($17,580)
($9,069)	2027	($7,128)	($19,640)

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($6,868)	2028	($6,631)	($18,598)
($6,389)	2029	($7,231)	($16,851)
($9,399)	2030	($10,869)	($25,240)
($9,648)	2031	($9,381)	($26,831)
($8,630)	2032	($6,146)	($22,204)
($5,714)	2033	($4,948)	($18,635)
($8,445)	2034	($6,539)	($18,491)
($1,831)	2035	($2,021)	($7,220)
($1,214)	2036	($1,767)	($3,218)
($722)	2037	($1,176)	($3,052)
$0	2038	($1,908)	($2,837)
$0	2039	($993)	($2,470)
$0	2040	$0	$0

Zeeland 1B

AFS Only		AGP Only	Full Upgrade
$8,340	2025	$6,921	$19,612
$4,221	2026	$5,084	$13,757
$7,066	2027	$5,996	$15,032
$5,258	2028	$5,459	$14,346
$4,691	2029	$5,585	$12,325
$6,875	2030	$8,855	$18,862
$7,428	2031	$7,767	$21,162
$7,102	2032	$5,168	$17,918
$4,417	2033	$3,969	$14,838
$7,157	2034	$5,644	$14,923
$1,487	2035	$1,719	$6,111
$1,052	2036	$1,511	$2,620
$524	2037	$852	$2,351
$0	2038	$1,517	$2,264
$0	2039	$717	$2,046
$0	2040	$0	$0

AFS Only
$0
$0
$0
$0
$0
$0
$0
$0
$0
$0
$0
$0

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$0
$0
$0
$0

Annual Revenue Requirer

2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
NPV

(2023 FCR model, peaker-Zeeland)

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AFS Only
($11,128)
($5,862)
($9,025)

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($6,686)
($6,398)
($9,746)
($9,854)
($8,794)
($6,360)
($8,653)
($1,839)
($1,215)
($719)
$0
$0
$0

AFS Only

$8,770
$4,428
$6,968
$5,040
$4,661
$7,076
$7,541
$7,211
$5,050
$7,292
$1,486
$1,050
$516
$0
$0
$0

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ment (K$)		Annual Revenue Requirer
Everything Investment	$49,100	
$6,674		2025
$6,674		2026
$6,674		2027
$6,674		2028
$6,674		2029
$6,674		2030
$6,674		2031
$6,674		2032
$6,674		2033
$6,674		2034
$6,674		2035
$6,674		2036
$6,674		2037
$6,674		2038
$6,674		2039
$6,674		2040
$63,051		**NPV**

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nent (K$)

AFS Investment	$22,000
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$2,991	
$28,251	

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Run ID	Year	Name	Capacity Factor	Energy Revenue(000s)
Zeeland Base	2025	Zeeland 1A	17%	$ 12,729
Zeeland Base	2026	Zeeland 1A	13%	$ 11,161
Zeeland Base	2027	Zeeland 1A	14%	$ 10,949
Zeeland Base	2028	Zeeland 1A	12%	$ 9,811
Zeeland Base	2029	Zeeland 1A	17%	$ 15,643
Zeeland Base	2030	Zeeland 1A	21%	$ 18,103
Zeeland Base	2031	Zeeland 1A	17%	$ 14,721
Zeeland Base	2032	Zeeland 1A	10%	$ 8,785
Zeeland Base	2033	Zeeland 1A	9%	$ 8,350
Zeeland Base	2034	Zeeland 1A	8%	$ 8,036
Zeeland Base	2035	Zeeland 1A	3%	$ 2,960
Zeeland Base	2036	Zeeland 1A	1%	$ 1,750
Zeeland Base	2037	Zeeland 1A	2%	$ 3,255
Zeeland Base	2038	Zeeland 1A		
Zeeland Base	2039	Zeeland 1A		
Zeeland Base	2040	Zeeland 1A		
Total	**ALL**		**11%**	**$ 126,251**
				NPV

Run ID	Year	Name	Capacity Factor	Energy Revenue(000s)
Zeeland Base	2025	Zeeland 1B	17%	$ 13,035
Zeeland Base	2026	Zeeland 1B	13%	$ 11,141
Zeeland Base	2027	Zeeland 1B	14%	$ 11,054
Zeeland Base	2028	Zeeland 1B	13%	$ 10,066
Zeeland Base	2029	Zeeland 1B	17%	$ 15,600
Zeeland Base	2030	Zeeland 1B	22%	$ 18,384
Zeeland Base	2031	Zeeland 1B	18%	$ 15,004
Zeeland Base	2032	Zeeland 1B	10%	$ 8,756
Zeeland Base	2033	Zeeland 1B	9%	$ 8,361
Zeeland Base	2034	Zeeland 1B	8%	$ 8,026
Zeeland Base	2035	Zeeland 1B	3%	$ 2,973
Zeeland Base	2036	Zeeland 1B	1%	$ 1,747
Zeeland Base	2037	Zeeland 1B	2%	$ 3,248
Zeeland Base	2038	Zeeland 1B		
Zeeland Base	2039	Zeeland 1B		
Zeeland Base	2040	Zeeland 1B		
Total	**ALL**		**11%**	**$ 127,395**
				NPV

Output DB **2024Adhoc_Zeeland_021224 for base; 2024Adhoc_Zeeland_021224 for sc**

*This analysis was done dispatching the Zeeland unit against the prices from our base case (103

*"Zeeland Case" are the Zeeland 1A and 1B units untouched; "Zeeland AGP Only" contains a red

Year	Capacity Price ($/mw-year)
2023	127,135
2024	129,932

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2025	132,790
2026	135,712
2027	138,698
2028	141,749
2029	144,867
2030	148,054
2031	151,312
2032	154,640
2033	158,043
2034	161,520
2035	165,073
2036	168,705
2037	172,416
2038	176,209
2039	180,086
2040	184,048

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Energy Revenue	Capacity Revenue	Total Revenue	Total Cost MWh	Total Cost
$ 12,728,570	$ 21,512,057	$ 34,240,627	$ 42	10,634,327.98
$ 11,161,270	$ 21,985,322	$ 33,146,592	$ 47	9,519,247.50
$ 10,948,550	$ 22,468,999	$ 33,417,549	$ 46	9,464,896.98
$ 9,811,290	$ 22,963,317	$ 32,774,607	$ 44	8,211,933.44
$ 15,643,130	$ 23,468,510	$ 39,111,640	$ 45	11,810,468.79
$ 18,102,680	$ 23,984,817	$ 42,087,497	$ 46	14,684,789.25
$ 14,720,940	$ 24,512,483	$ 39,233,423	$ 46	12,312,149.72
$ 8,784,500	$ 25,051,758	$ 33,836,258	$ 50	7,408,811.97
$ 8,349,500	$ 25,602,896	$ 33,952,396	$ 53	7,007,021.76
$ 8,035,650	$ 26,166,160	$ 34,201,810	$ 57	6,582,787.20
$ 2,959,550	$ 26,741,816	$ 29,701,366	$ 64	2,470,101.10
$ 1,749,830	$ 27,330,136	$ 29,079,966	$ 66	1,410,285.48
$ 3,255,100	$ 27,931,399	$ 31,186,499	$ 68	2,208,001.28
$ 126,250,560	**$ 319,719,669**	**$ 445,970,229**		**$ 103,724,822**
$87,723,094.56	**$201,385,988.42**	**$289,109,082.98**		**$72,302,967.62**

Energy Revenue	Capacity Revenue	Total Revenue	Total Cost MWh	Total Cost
$ 13,035,180	$ 21,512,057	$ 34,547,237	$ 42	10,905,961.85
$ 11,140,630	$ 21,985,322	$ 33,125,952	$ 46	9,503,161.36
$ 11,053,790	$ 22,468,999	$ 33,522,789	$ 45	9,566,013.38
$ 10,066,200	$ 22,963,317	$ 33,029,517	$ 44	8,452,730.88
$ 15,600,140	$ 23,468,510	$ 39,068,650	$ 45	11,772,781.14
$ 18,383,870	$ 23,984,817	$ 42,368,687	$ 46	14,946,826.16
$ 15,004,250	$ 24,512,483	$ 39,516,733	$ 46	12,586,928.10
$ 8,756,350	$ 25,051,758	$ 33,808,108	$ 50	7,386,929.75
$ 8,360,530	$ 25,602,896	$ 33,963,426	$ 53	7,003,101.90
$ 8,026,000	$ 26,166,160	$ 34,192,160	$ 57	6,574,175.91
$ 2,973,010	$ 26,741,816	$ 29,714,826	$ 64	2,482,731.90
$ 1,746,840	$ 27,330,136	$ 29,076,976	$ 66	1,409,750.28
$ 3,247,920	$ 27,931,399	$ 31,179,319	$ 68	2,199,356.22
$ 127,394,710	**$ 319,719,669**	**$ 447,114,379**		**$ 104,790,449**
$88,591,941.89	**$201,385,988.42**	**$289,977,930.30**		**$73,110,809.20**

enarios

), with shaping applied to better replicate peaks and valleys of a normal price stream

luction on heat rate by 2.7%, and an increase in capacity by 25 MW; "Zeeland Everything" is AGP only + mini

	Capacity (MW)
Zeeland	180

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Zeeland Modified	205
eFOR	0.9

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Total Value	Dispatch Cost	Output (MWh)	Fuel Usage (mmBTU)
23,606,298.70	$ 32	251,462	2,741,096
23,627,344.43	$ 35	204,715	2,229,859
23,952,652.03	$ 35	207,837	2,267,491
24,562,673.55	$ 35	187,316	2,049,207
27,301,171.17	$ 36	261,931	2,861,509
27,402,707.93	$ 36	320,979	3,507,019
26,921,273.44	$ 37	265,577	2,905,145
26,427,445.82	$ 37	148,861	1,631,148
26,945,374.70	$ 39	131,316	1,436,875
27,619,022.98	$ 42	116,160	1,265,826
27,231,264.61	$ 45	38,686	421,356
27,669,680.17	$ 46	21,459	235,874
28,978,497.36	$ 48	32,576	354,022
$ 342,245,407	**$ 504**	**$ 2,188,875**	**$ 23,906,427**
$216,806,115.35			

Total Value	Dispatch Cost	Output (MWh)	Fuel Usage (mmBTU)
23,641,274.83	$ 32	259,357	2,823,155
23,622,790.57	$ 35	204,457	2,224,547
23,956,775.63	$ 35	210,566	2,294,445
24,576,786.11	$ 35	194,048	2,119,566
27,295,868.82	$ 36	261,269	2,851,861
27,421,861.02	$ 36	327,494	3,573,511
26,929,805.06	$ 36	270,978	2,961,089
26,421,178.04	$ 37	148,481	1,625,930
26,960,324.56	$ 39	131,910	1,442,217
27,617,984.27	$ 41	116,131	1,264,149
27,232,093.81	$ 44	39,006	424,514
27,667,225.37	$ 46	21,477	235,925
28,979,962.42	$ 48	32,482	352,568
$ 342,323,931	**$ 39**	**2217656.0**	**24193477.0**
$216,867,121.11			

mum load set to 25%; "Zeeland AFS Only" only includes minimum capacity rampdown

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Run ID	Year	Name	Capacity Factor	Energy Revenue(000s)
Zeeland AGP Only	2025	Zeeland 1A	25%	$ 21,424
Zeeland AGP Only	2026	Zeeland 1A	18%	$ 17,282
Zeeland AGP Only	2027	Zeeland 1A	20%	$ 17,929
Zeeland AGP Only	2028	Zeeland 1A	19%	$ 16,608
Zeeland AGP Only	2029	Zeeland 1A	22%	$ 22,788
Zeeland AGP Only	2030	Zeeland 1A	30%	$ 28,646
Zeeland AGP Only	2031	Zeeland 1A	26%	$ 24,333
Zeeland AGP Only	2032	Zeeland 1A	15%	$ 14,869
Zeeland AGP Only	2033	Zeeland 1A	12%	$ 13,286
Zeeland AGP Only	2034	Zeeland 1A	12%	$ 14,402
Zeeland AGP Only	2035	Zeeland 1A	4%	$ 4,855
Zeeland AGP Only	2036	Zeeland 1A	3%	$ 3,494
Zeeland AGP Only	2037	Zeeland 1A	3%	$ 4,424
Zeeland AGP Only	2038	Zeeland 1A	1%	$ 1,908
Zeeland AGP Only	2039	Zeeland 1A	1%	$ 988
Zeeland AGP Only	2040	Zeeland 1A	0%	$ -
Total	**ALL**		**13%**	**$ 207,236**
				NPV

Run ID	Year	Name	Capacity Factor	Energy Revenue(000s)
Zeeland AGP Only	2025	Zeeland 1B	25%	$ 21,457
Zeeland AGP Only	2026	Zeeland 1B	18%	$ 17,301
Zeeland AGP Only	2027	Zeeland 1B	20%	$ 18,181
Zeeland AGP Only	2028	Zeeland 1B	19%	$ 16,698
Zeeland AGP Only	2029	Zeeland 1B	23%	$ 22,831
Zeeland AGP Only	2030	Zeeland 1B	30%	$ 29,253
Zeeland AGP Only	2031	Zeeland 1B	26%	$ 24,385
Zeeland AGP Only	2032	Zeeland 1B	15%	$ 14,903
Zeeland AGP Only	2033	Zeeland 1B	12%	$ 13,309
Zeeland AGP Only	2034	Zeeland 1B	13%	$ 14,565
Zeeland AGP Only	2035	Zeeland 1B	4%	$ 4,994
Zeeland AGP Only	2036	Zeeland 1B	3%	$ 3,514
Zeeland AGP Only	2037	Zeeland 1B	3%	$ 4,424
Zeeland AGP Only	2038	Zeeland 1B	1%	$ 1,908
Zeeland AGP Only	2039	Zeeland 1B	1%	$ 993
Zeeland AGP Only	2040	Zeeland 1B	0%	$ -
Total	**ALL**		**13%**	**$ 208,714**
				NPV

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Energy Revenue	Capacity Revenue	Total Revenue	Total Cost MWh	Total Cost
$ 21,424,100	$ 24,499,842	$ 45,923,942	$ 40	17,822,006.84
$ 17,282,370	$ 25,038,839	$ 42,321,209	$ 44	14,578,325.19
$ 17,929,100	$ 25,589,693	$ 43,518,793	$ 43	15,351,894.82
$ 16,607,860	$ 26,152,667	$ 42,760,527	$ 41	13,862,203.15
$ 22,788,400	$ 26,728,025	$ 49,516,425	$ 43	17,333,496.42
$ 28,645,730	$ 27,316,042	$ 55,961,772	$ 44	23,271,044.16
$ 24,332,830	$ 27,916,995	$ 52,249,825	$ 44	20,343,857.26
$ 14,868,990	$ 28,531,169	$ 43,400,159	$ 47	12,532,251.24
$ 13,285,680	$ 29,158,854	$ 42,444,534	$ 50	10,962,491.55
$ 14,401,800	$ 29,800,349	$ 44,202,149	$ 54	12,069,776.22
$ 4,855,480	$ 30,455,957	$ 35,311,437	$ 60	4,069,901.57
$ 3,493,770	$ 31,125,988	$ 34,619,758	$ 62	2,903,928.56
$ 4,423,630	$ 31,810,760	$ 36,234,390	$ 65	3,056,403.46
$ 1,908,120	$ 32,510,596	$ 34,418,716	$ 70	1,517,923.22
$ 987,650	$ 33,225,829	$ 34,213,479	$ 72	713,539.96
$ -	$ 33,956,798	$ 33,956,798		-
$ 207,235,510	**$ 463,818,402**	**$ 671,053,912**		**$ 170,389,044**
$142,905,357.16	**$265,509,346.13**	**$408,414,703.29**		**$117,761,607.89**

Energy Revenue	Capacity Revenue	Total Revenue	Total Cost MWh	Total Cost
$ 21,456,610	$ 24,499,842	$ 45,956,452	$ 40	17,827,455.76
$ 17,300,960	$ 25,038,839	$ 42,339,799	$ 44	14,586,718.50
$ 18,181,410	$ 25,589,693	$ 43,771,103	$ 43	15,562,023.52
$ 16,697,590	$ 26,152,667	$ 42,850,257	$ 41	13,911,700.92
$ 22,831,020	$ 26,728,025	$ 49,559,045	$ 43	17,358,039.02
$ 29,252,940	$ 27,316,042	$ 56,568,982	$ 44	23,802,098.76
$ 24,385,020	$ 27,916,995	$ 52,302,015	$ 44	20,353,484.45
$ 14,902,820	$ 28,531,169	$ 43,433,989	$ 47	12,555,352.80
$ 13,308,720	$ 29,158,854	$ 42,467,574	$ 49	10,972,347.06
$ 14,564,690	$ 29,800,349	$ 44,365,039	$ 54	12,218,537.10
$ 4,993,570	$ 30,455,957	$ 35,449,527	$ 60	4,201,659.84
$ 3,514,060	$ 31,125,988	$ 34,640,048	$ 61	2,920,905.15
$ 4,423,630	$ 31,810,760	$ 36,234,390	$ 65	3,051,686.06
$ 1,908,120	$ 32,510,596	$ 34,418,716	$ 70	1,516,841.77
$ 992,780	$ 33,225,829	$ 34,218,609	$ 71	717,319.98
$ -	$ 33,956,798	$ 33,956,798		-
$ 208,713,940	**$ 463,818,402**	**$ 672,532,342**		**$ 171,556,171**
$143,885,391.24	**$265,509,346.13**	**$409,394,737.38**		**$118,524,235.43**

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Total Value	Dispatch Cos	Output (MWh)	Fuel Usage (mmBTU)
28,101,935.49	$ 31	448,804	4,744,320
27,742,883.67	$ 34	329,901	3,487,252
28,166,898.50	$ 34	358,187	3,790,373
28,898,323.42	$ 34	338,185	3,580,572
32,182,928.82	$ 35	403,386	4,272,378
32,690,727.63	$ 35	532,762	5,642,247
31,905,967.45	$ 36	465,961	4,946,282
30,867,907.35	$ 36	265,739	2,821,437
31,482,042.75	$ 38	221,241	2,347,912
32,132,372.88	$ 40	223,763	2,365,053
31,241,535.21	$ 43	67,843	716,999
31,715,829.27	$ 45	47,203	501,893
33,177,986.10	$ 47	47,174	498,435
32,900,793.05	$ 50	21,629	230,598
33,499,939.43	$ 52	9,974	104,775
33,956,797.63	$ 24		
$ 500,664,869	**$ 615**	**$ 3,781,752**	**$ 40,050,526**
$290,653,095.41			

Total Value	Dispatch Cos	Output (MWh)	Fuel Usage (mmBTU)
28,128,996.57	$ 31	449,734	4,749,329
27,753,080.36	$ 34	330,390	3,488,799
28,209,079.80	$ 34	363,344	3,840,855
28,938,555.65	$ 34	340,806	3,604,423
32,201,006.22	$ 35	404,522	4,280,680
32,766,883.03	$ 35	546,421	5,781,011
31,948,530.26	$ 35	467,359	4,957,605
30,878,635.79	$ 36	266,568	2,827,789
31,495,227.24	$ 38	221,798	2,351,857
32,146,502.00	$ 40	226,689	2,393,941
31,247,866.94	$ 43	70,168	741,125
31,719,142.68	$ 44	47,595	505,646
33,182,703.50	$ 47	47,174	497,896
32,901,874.50	$ 49	21,629	230,489
33,501,289.41	$ 51	10,062	105,396
33,956,797.63	$ 23		
$ 500,976,172	**$ 38**	**3814259.0**	**40356841.0**
$290,870,501.95			

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Run ID	Year	Name
Zeeland Everything	2025	Zeeland 1A
Zeeland Everything	2026	Zeeland 1A
Zeeland Everything	2027	Zeeland 1A
Zeeland Everything	2028	Zeeland 1A
Zeeland Everything	2029	Zeeland 1A
Zeeland Everything	2030	Zeeland 1A
Zeeland Everything	2031	Zeeland 1A
Zeeland Everything	2032	Zeeland 1A
Zeeland Everything	2033	Zeeland 1A
Zeeland Everything	2034	Zeeland 1A
Zeeland Everything	2035	Zeeland 1A
Zeeland Everything	2036	Zeeland 1A
Zeeland Everything	2037	Zeeland 1A
Zeeland Everything	2038	Zeeland 1A
Zeeland Everything	2039	Zeeland 1A
Zeeland Everything	2040	Zeeland 1A
Total	**ALL**	

Run ID	Year	Name
Zeeland Everything	2025	Zeeland 1B
Zeeland Everything	2026	Zeeland 1B
Zeeland Everything	2027	Zeeland 1B
Zeeland Everything	2028	Zeeland 1B
Zeeland Everything	2029	Zeeland 1B
Zeeland Everything	2030	Zeeland 1B
Zeeland Everything	2031	Zeeland 1B
Zeeland Everything	2032	Zeeland 1B
Zeeland Everything	2033	Zeeland 1B
Zeeland Everything	2034	Zeeland 1B
Zeeland Everything	2035	Zeeland 1B
Zeeland Everything	2036	Zeeland 1B
Zeeland Everything	2037	Zeeland 1B
Zeeland Everything	2038	Zeeland 1B
Zeeland Everything	2039	Zeeland 1B
Zeeland Everything	2040	Zeeland 1B
Total	**ALL**	

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Capacity Factor	Energy Revenue(00(	Energy Revenue	Capacity Revenue	Total Revenue
49%	$ 37,358	$ 37,358,290	$ 24,499,842	$ 61,858,132
33%	$ 28,181	$ 28,180,960	$ 25,038,839	$ 53,219,799
38%	$ 30,122	$ 30,122,090	$ 25,589,693	$ 55,711,783
36%	$ 28,522	$ 28,522,150	$ 26,152,667	$ 54,674,817
35%	$ 32,342	$ 32,341,790	$ 26,728,025	$ 59,069,815
48%	$ 43,092	$ 43,092,320	$ 27,316,042	$ 70,408,362
47%	$ 40,973	$ 40,973,300	$ 27,916,995	$ 68,890,295
34%	$ 30,084	$ 30,084,090	$ 28,531,169	$ 58,615,259
29%	$ 26,700	$ 26,700,050	$ 29,158,854	$ 55,858,904
26%	$ 26,362	$ 26,362,140	$ 29,800,349	$ 56,162,489
9%	$ 9,730	$ 9,729,760	$ 30,455,957	$ 40,185,717
4%	$ 4,825	$ 4,825,440	$ 31,125,988	$ 35,951,428
4%	$ 6,115	$ 6,115,490	$ 31,810,760	$ 37,926,250
2%	$ 2,818	$ 2,817,680	$ 32,510,596	$ 35,328,276
2%	$ 2,333	$ 2,333,270	$ 33,225,829	$ 35,559,099
0%	$ -	$ -	$ 33,956,798	$ 33,956,798
25%	**$ 349,559**	**$ 349,558,820**	**$ 463,818,402**	**$ 813,377,222**
	NPV	**$239,840,914.81**	**$265,509,346.13**	**$505,350,260.94**

Capacity Factor	Energy Revenue(00(	Energy Revenue	Capacity Revenue	Total Revenue
50%	$ 38,097	$ 38,096,640	$ 24,499,842	$ 62,596,482
34%	$ 28,721	$ 28,720,990	$ 25,038,839	$ 53,759,829
38%	$ 30,694	$ 30,693,950	$ 25,589,693	$ 56,283,643
36%	$ 28,664	$ 28,663,780	$ 26,152,667	$ 54,816,447
35%	$ 32,451	$ 32,450,780	$ 26,728,025	$ 59,178,805
49%	$ 43,623	$ 43,623,390	$ 27,316,042	$ 70,939,432
49%	$ 41,836	$ 41,835,500	$ 27,916,995	$ 69,752,495
35%	$ 30,960	$ 30,960,470	$ 28,531,169	$ 59,491,639
29%	$ 26,995	$ 26,995,110	$ 29,158,854	$ 56,153,964
26%	$ 26,517	$ 26,517,350	$ 29,800,349	$ 56,317,699
9%	$ 10,193	$ 10,193,410	$ 30,455,957	$ 40,649,367
4%	$ 4,964	$ 4,964,460	$ 31,125,988	$ 36,090,448
4%	$ 6,300	$ 6,300,180	$ 31,810,760	$ 38,110,940
2%	$ 2,837	$ 2,837,170	$ 32,510,596	$ 35,347,766
2%	$ 2,470	$ 2,470,480	$ 33,225,829	$ 35,696,309
0%	$ -	$ -	$ 33,956,798	$ 33,956,798
25%	**$ 355,324**	**$ 355,323,660**	**$ 463,818,402**	**$ 819,142,062**
	NPV	**$243,711,407.16**	**$265,509,346.13**	**$509,220,753.29**

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Total Cost MWh	Total Cost	Total Value	Dispatch Cos	Output (MWh)
$ 34	29,936,219.56	31,921,912.77	$ 31	878,926
$ 38	22,870,501.59	30,349,297.27	$ 34	598,861
$ 36	24,166,233.30	31,545,550.02	$ 34	673,905
$ 35	22,766,849.35	31,907,967.22	$ 34	644,041
$ 38	24,098,186.90	34,971,628.34	$ 35	631,835
$ 39	33,489,598.29	36,918,763.50	$ 35	867,831
$ 39	33,089,865.90	35,800,428.81	$ 36	851,734
$ 40	24,587,063.51	34,028,195.08	$ 36	609,647
$ 42	21,658,544.64	34,200,359.66	$ 38	514,944
$ 46	21,420,688.52	34,741,800.58	$ 40	469,546
$ 51	8,184,462.28	32,001,254.50	$ 43	159,479
$ 55	3,904,698.80	32,046,729.03	$ 45	71,410
$ 59	4,383,251.18	33,542,998.38	$ 47	74,723
$ 63	2,251,281.60	33,076,994.67	$ 50	35,940
$ 65	1,917,131.10	33,641,968.29	$ 52	29,654
	-	33,956,797.63	$ 24	
	$ 278,724,577	**$ 534,652,646**	**$ 615**	**$ 7,112,476**
	$191,142,083.17	**$314,208,177.77**		

Total Cost MWh	Total Cost	Total Value	Dispatch Cos	Output (MWh)
$ 34	30,517,779.24	32,078,703.09	$ 31	899,964
$ 38	23,259,791.87	30,500,036.99	$ 34	614,201
$ 36	24,597,519.14	31,686,124.18	$ 34	689,779
$ 35	22,798,763.64	32,017,682.93	$ 34	648,429
$ 38	24,097,756.65	35,081,048.59	$ 35	634,987
$ 38	33,808,394.20	37,131,037.59	$ 35	881,345
$ 39	33,749,150.96	36,003,343.75	$ 35	872,522
$ 40	25,305,078.12	34,186,560.47	$ 36	630,892
$ 42	21,841,124.76	34,312,839.54	$ 38	521,766
$ 45	21,496,695.54	34,821,003.56	$ 40	473,287
$ 51	8,594,108.70	32,055,258.08	$ 43	168,843
$ 55	4,029,706.26	32,060,741.57	$ 44	73,926
$ 58	4,550,645.26	33,560,294.30	$ 47	77,882
$ 62	2,263,836.32	33,083,929.95	$ 49	36,326
$ 64	2,046,148.86	33,650,160.53	$ 51	31,738
	-	33,956,797.63	$ 23	
	$ 282,956,500	**$ 536,185,563**	**$ 38**	**7255887.0**
	$193,951,772.11	**$315,268,981.19**		

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Fuel Usage (mmBTU)	Run ID	Year
8,306,608	Zeeland AFS Upgrade	2025
5,664,100	Zeeland AFS Upgrade	2026
6,375,111	Zeeland AFS Upgrade	2027
6,107,720	Zeeland AFS Upgrade	2028
5,981,174	Zeeland AFS Upgrade	2029
8,218,710	Zeeland AFS Upgrade	2030
8,057,805	Zeeland AFS Upgrade	2031
5,780,718	Zeeland AFS Upgrade	2032
4,874,764	Zeeland AFS Upgrade	2033
4,444,496	Zeeland AFS Upgrade	2034
1,513,215	Zeeland AFS Upgrade	2035
674,264	Zeeland AFS Upgrade	2036
704,534	Zeeland AFS Upgrade	2037
339,852	Zeeland AFS Upgrade	2038
279,812	Zeeland AFS Upgrade	2039
	Zeeland AFS Upgrade	2040
$ 67,322,883	**Total**	**ALL**

Fuel Usage (mmBTU)	Run ID	Year
8,474,883	Zeeland AFS Upgrade	2025
5,789,800	Zeeland AFS Upgrade	2026
6,501,396	Zeeland AFS Upgrade	2027
6,126,151	Zeeland AFS Upgrade	2028
5,988,921	Zeeland AFS Upgrade	2029
8,316,637	Zeeland AFS Upgrade	2030
8,224,231	Zeeland AFS Upgrade	2031
5,962,201	Zeeland AFS Upgrade	2032
4,919,744	Zeeland AFS Upgrade	2033
4,463,054	Zeeland AFS Upgrade	2034
1,596,605	Zeeland AFS Upgrade	2035
695,508	Zeeland AFS Upgrade	2036
731,785	Zeeland AFS Upgrade	2037
342,280	Zeeland AFS Upgrade	2038
298,303	Zeeland AFS Upgrade	2039
	Zeeland AFS Upgrade	2040
68431499.0	**Total**	**ALL**

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Name	Capacity Factor	Energy Revenue(000s)	Energy Revenue	Capacity Revenue
Zeeland 1A	34%	$ 23,357	$ 23,357,120	$ 21,512,057
Zeeland 1A	22%	$ 16,772	$ 16,771,920	$ 21,985,322
Zeeland 1A	28%	$ 20,017	$ 20,017,350	$ 22,468,999
Zeeland 1A	24%	$ 16,680	$ 16,679,650	$ 22,963,317
Zeeland 1A	27%	$ 22,032	$ 22,031,820	$ 23,468,510
Zeeland 1A	35%	$ 27,502	$ 27,501,560	$ 23,984,817
Zeeland 1A	32%	$ 24,369	$ 24,368,990	$ 24,512,483
Zeeland 1A	22%	$ 17,415	$ 17,414,640	$ 25,051,758
Zeeland 1A	17%	$ 14,064	$ 14,063,520	$ 25,602,896
Zeeland 1A	18%	$ 16,480	$ 16,480,240	$ 26,166,160
Zeeland 1A	5%	$ 4,791	$ 4,790,680	$ 26,741,816
Zeeland 1A	3%	$ 2,964	$ 2,964,310	$ 27,330,136
Zeeland 1A	3%	$ 3,977	$ 3,977,430	$ 27,931,399
Zeeland 1A				
Zeeland 1A				
Zeeland 1A				
	21%	**$ 210,419**	**$ 210,419,230**	**$ 319,719,669**
		NPV	**$146,158,409.20**	**$201,385,988.42**

Name	Capacity Factor	Energy Revenue(000s)	Energy Revenue	Capacity Revenue
Zeeland 1B	36%	$ 24,164	$ 24,163,540	$ 21,512,057
Zeeland 1B	23%	$ 17,003	$ 17,002,710	$ 21,985,322
Zeeland 1B	28%	$ 20,079	$ 20,078,980	$ 22,468,999
Zeeland 1B	24%	$ 16,752	$ 16,752,150	$ 22,963,317
Zeeland 1B	27%	$ 21,998	$ 21,997,810	$ 23,468,510
Zeeland 1B	36%	$ 28,130	$ 28,130,280	$ 23,984,817
Zeeland 1B	33%	$ 24,858	$ 24,858,180	$ 24,512,483
Zeeland 1B	22%	$ 17,550	$ 17,550,470	$ 25,051,758
Zeeland 1B	17%	$ 14,721	$ 14,720,750	$ 25,602,896
Zeeland 1B	19%	$ 16,679	$ 16,678,960	$ 26,166,160
Zeeland 1B	5%	$ 4,812	$ 4,811,690	$ 26,741,816
Zeeland 1B	3%	$ 2,962	$ 2,962,280	$ 27,330,136
Zeeland 1B	3%	$ 3,967	$ 3,966,930	$ 27,931,399
Zeeland 1B				
Zeeland 1B				
Zeeland 1B				
	21%	**$ 213,675**	**$ 213,674,730**	**$ 319,719,669**
		NPV	**$148,460,895.25**	**$201,385,988.42**

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Total Revenue	Total Cost MWh	Total Cost	Total Value	Dispatch Cost
$ 44,869,177	$ 36	18,973,989.00	25,895,187.68	$ 32
$ 38,757,242	$ 41	13,740,020.28	25,017,221.65	$ 35
$ 42,486,349	$ 39	16,530,527.20	25,955,821.81	$ 35
$ 39,642,967	$ 38	13,470,403.12	26,172,563.87	$ 35
$ 45,500,330	$ 40	16,501,178.00	28,999,151.96	$ 36
$ 51,486,377	$ 41	21,560,052.05	29,926,325.13	$ 36
$ 48,881,473	$ 41	19,740,083.40	29,141,389.76	$ 37
$ 42,466,398	$ 44	14,510,532.96	27,955,864.83	$ 37
$ 39,666,416	$ 45	11,424,297.60	28,242,118.86	$ 39
$ 42,646,400	$ 50	13,740,092.80	28,906,307.38	$ 42
$ 31,532,496	$ 56	3,957,178.68	27,575,317.03	$ 45
$ 30,294,446	$ 60	2,462,684.70	27,831,760.95	$ 46
$ 31,908,829	$ 63	2,731,602.65	29,177,225.99	$ 48
$ 530,138,899		**$ 169,342,642**	**$ 360,796,257**	**$ 504**
$347,544,397.62		**$117,679,819.09**	**$229,864,578.52**	

Total Revenue	Total Cost MWh	Total Cost	Total Value	Dispatch Cost
$ 45,675,597	$ 36	19,675,769.40	25,999,827.28	$ 32
$ 38,988,032	$ 41	13,931,639.01	25,056,392.92	$ 35
$ 42,547,979	$ 38	16,533,958.76	26,014,020.25	$ 35
$ 39,715,467	$ 37	13,492,853.84	26,222,613.15	$ 35
$ 45,466,320	$ 40	16,433,676.08	29,032,643.88	$ 36
$ 52,115,097	$ 40	22,022,505.45	30,092,591.73	$ 36
$ 49,370,663	$ 41	20,128,260.36	29,242,402.80	$ 36
$ 42,602,228	$ 43	14,597,908.30	28,004,319.49	$ 37
$ 40,323,646	$ 46	12,053,559.44	28,270,087.02	$ 39
$ 42,845,120	$ 49	13,866,652.16	28,978,468.02	$ 41
$ 31,553,506	$ 55	3,969,199.70	27,584,306.01	$ 44
$ 30,292,416	$ 60	2,459,373.00	27,833,042.65	$ 46
$ 31,898,329	$ 62	2,715,068.40	29,183,260.24	$ 48
$ 533,394,399		**$ 171,880,424**	**$ 361,513,975**	**$ 39**
$349,846,883.67		**$119,479,591.85**	**$230,367,291.82**	

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Output (MWh)	Fuel Usage (mmBTU)
521,550	5,158,652
335,286	3,312,392
428,252	4,240,567
358,828	3,560,750
408,445	4,044,930
530,905	5,260,132
480,294	4,755,780
333,116	3,307,844
251,415	2,493,862
277,018	2,740,734
71,019	704,384
41,251	408,189
43,601	430,044

$ 4,080,980	**$ 40,418,260**

Output (MWh)	Fuel Usage (mmBTU)
543,830	5,359,345
341,713	3,364,871
430,684	4,249,692
361,448	3,574,180
407,986	4,027,063
545,787	5,389,954
493,098	4,866,608
336,590	3,330,789
264,797	2,615,744
281,728	2,778,466
71,530	707,139
41,334	407,677
43,455	427,183

4163980.0	**41098711.0**

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Month	Zeeland 1A	Zeeland 1B
2024_01	922,343	920,782
2024_02	1,171,997	1,170,017
2024_03	1,214,796	1,212,762
2024_04	1,107,606	1,110,136
2024_05	1,150,019	1,193,389
2024_06	907,368	912,914
2024_07	767,090	762,386
2024_08	838,366	835,837
2024_09	557,166	554,266
2024_10	376,798	406,555
2024_11	202,692	202,349
2024_12	73,689	73,566
2025_01	221,075	250,944
2025_02	94,344	94,184
2025_03	184,988	190,215
2025_04	253,433	301,020
2025_05	192,387	192,062
2025_06	294,211	301,063
2025_07	487,869	484,542
2025_08	527,375	525,416
2025_09	261,579	260,253
2025_10	149,840	149,586
2025_11		
2025_12	73,995	73,870
2026_01	246,062	246,351
2026_02		
2026_03		
2026_04	199,787	199,449
2026_05	307,080	306,560
2026_06	278,803	276,886
2026_07	457,491	454,859
2026_08	334,228	335,266
2026_09	151,124	150,326
2026_10	98,044	97,878
2026_11	73,995	73,870
2026_12	83,245	83,104
2027_01	79,545	79,410
2027_02	38,847	38,782
2027_03	130,651	130,432
2027_04	99,893	99,724
2027_05	64,746	96,031
2027_06	154,517	153,455
2027_07	483,196	479,878
2027_08	568,122	568,605
2027_09	185,504	184,595
2027_10	270,082	271,472

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2027_11	170,189	169,901
2027_12	22,199	22,161
2028_01		
2028_02		
2028_03		
2028_04	120,242	195,755
2028_05	53,646	53,556
2028_06	393,085	391,960
2028_07	497,362	495,699
2028_08	300,126	298,068
2028_09	251,874	250,544
2028_10	299,680	299,173
2028_11	133,191	134,812
2028_12		
2029_01		
2029_02	224,305	223,930
2029_03	31,448	31,395
2029_04	284,881	286,246
2029_05	127,642	129,272
2029_06	249,740	248,028
2029_07	627,636	623,453
2029_08	555,635	551,908
2029_09	371,748	369,813
2029_10	75,845	75,717
2029_11	122,092	121,885
2029_12	190,537	190,215
2030_01	83,245	83,104
2030_02	181,537	181,928
2030_03	31,448	31,395
2030_04	196,087	197,602
2030_05	316,109	317,427
2030_06	267,193	265,874
2030_07	847,144	854,801
2030_08	624,788	623,793
2030_09	374,879	373,026
2030_10	298,549	359,003
2030_11	157,240	156,973
2030_12	128,801	128,586
2031_01	176,659	178,216
2031_02	184,569	246,475
2031_03	87,399	87,251
2031_04		
2031_05	119,012	118,811
2031_06	489,543	487,909
2031_07	676,287	674,367
2031_08	549,001	545,764
2031_09	360,477	358,686

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2031_10	128,310	129,949
2031_11	66,944	66,831
2031_12	66,944	66,831
2032_01	33,472	33,415
2032_02		
2032_03		
2032_04	31,613	31,559
2032_05	31,613	31,559
2032_06	205,096	205,390
2032_07	427,295	424,501
2032_08	356,238	355,465
2032_09	239,689	238,423
2032_10	74,383	74,257
2032_11	31,613	31,559
2032_12	200,139	199,803
2033_01	142,743	142,516
2033_02		
2033_03		
2033_04		
2033_05	46,489	46,410
2033_06	178,963	177,732
2033_07	402,116	400,394
2033_08	249,873	259,892
2033_09	213,998	212,924
2033_10	29,753	29,703
2033_11	68,804	68,687
2033_12	104,136	103,959
2034_01	255,011	255,281
2034_02		
2034_03		
2034_04		
2034_05	81,821	81,682
2034_06	136,755	135,814
2034_07	280,263	280,012
2034_08	207,665	207,913
2034_09	97,901	97,384
2034_10	63,225	63,118
2034_11	44,630	44,554
2034_12	98,557	98,390
2035_01	109,600	109,414
2035_02	39,010	38,944
2035_03	31,580	31,526
2035_04		
2035_05		
2035_06		
2035_07	94,448	98,823
2035_08	86,015	85,424

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2035_09	60,703	60,382
2035_10		
2035_11		
2035_12		
2036_01		
2036_02		
2036_03		
2036_04		
2036_05		
2036_06		
2036_07	126,361	127,165
2036_08	109,513	108,760
2036_09		
2036_10		
2036_11		
2036_12		
2037_01		
2037_02	189,083	188,763
2037_03		
2037_04		
2037_05		
2037_06		
2037_07	75,737	75,217
2037_08	89,202	88,588
2037_09		
2037_10		
2037_11		
2037_12		
2038_01		
2038_02		
2038_03		
2038_04		
2038_05		
2038_06		
2038_07	50,439	50,092
2038_08	67,252	66,789
2038_09	16,809	16,720
2038_10		
2038_11		
2038_12		
2039_01		
2039_02	70,765	70,650
2039_03		
2039_04		
2039_05		
2039_06		
2039_07		

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2039_08
2039_09
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2039_12
2040_01
2040_02
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2040_12

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Month	Zeeland 1A	Zeeland 1B
2024_01	1,300,643	1,298,441
2024_02	1,390,271	1,387,917
2024_03	1,401,286	1,401,042
2024_04	1,327,900	1,325,652
2024_05	1,325,487	1,324,823
2024_06	1,267,512	1,268,825
2024_07	1,118,017	1,118,030
2024_08	1,270,478	1,269,711
2024_09	948,942	951,546
2024_10	602,381	601,361
2024_11	377,270	412,005
2024_12	156,079	156,596
2025_01	340,582	340,010
2025_02	184,542	184,230
2025_03	302,732	304,290
2025_04	404,753	404,067
2025_05	265,808	265,358
2025_06	760,749	764,428
2025_07	724,174	725,793
2025_08	914,026	914,082
2025_09	326,505	327,503
2025_10	259,188	258,750
2025_11	178,322	178,020
2025_12	82,940	82,800
2026_01	278,656	278,972
2026_02		
2026_03		
2026_04	289,972	289,481
2026_05	384,616	383,965
2026_06	401,077	400,824
2026_07	718,987	718,588
2026_08	614,984	614,596
2026_09	232,366	232,593
2026_10	234,306	238,050
2026_11	149,819	149,571
2026_12	182,469	182,160
2027_01	91,234	91,080
2027_02	43,544	43,470
2027_03	147,219	146,970
2027_04	219,493	219,121
2027_05	167,137	170,874
2027_06	308,699	308,525
2027_07	824,778	826,314
2027_08	911,343	910,789
2027_09	349,125	349,534
2027_10	412,628	411,929
2027_11	257,115	267,030
2027_12	58,058	95,220
2028_01		
2028_02		

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Month	Zeeland 1A	Zeeland 1B
2024_01	1,300,643	1,409,023
2024_02	1,390,271	1,318,119
2024_03	1,374,481	1,369,853
2024_04	1,323,676	1,320,433
2024_05	1,307,191	1,305,355
2024_06	1,251,030	1,250,693
2024_07	1,134,241	1,132,971
2024_08	1,291,508	1,288,413
2024_09	1,134,365	1,138,250
2024_10	906,052	904,284
2024_11	788,955	868,042
2024_12	276,043	280,361
2025_01	340,582	544,214
2025_02	184,542	465,344
2025_03	552,458	550,580
2025_04	888,620	919,241
2025_05	560,561	742,971
2025_06	890,629	890,160
2025_07	1,179,649	1,181,335
2025_08	1,344,362	1,342,331
2025_09	414,125	415,272
2025_10	310,032	310,857
2025_11	538,368	542,202
2025_12	143,673	143,183
2026_01	278,656	332,366
2026_02		171,443
2026_03	114,461	176,252
2026_04	581,151	586,496
2026_05	459,718	459,433
2026_06	611,267	612,873
2026_07	954,754	1,058,499
2026_08	1,015,948	1,021,838
2026_09	392,184	390,850
2026_10	260,881	259,990
2026_11	268,307	269,281
2026_12	235,584	236,668
2027_01	91,234	114,794
2027_02	43,544	105,503
2027_03	179,592	178,979
2027_04	449,098	526,118
2027_05	416,051	462,774
2027_06	656,637	660,637
2027_07	1,163,957	1,174,016
2027_08	1,245,042	1,240,895
2027_09	684,308	703,855
2027_10	561,774	577,412

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2027_11	367,059	367,120
2027_12	144,123	143,639
2028_01		30,144
2028_02		84,066
2028_03	136,112	137,531
2028_04	677,450	678,796
2028_05	553,917	597,917
2028_06	898,006	897,628
2028_07	1,051,341	1,063,320
2028_08	822,865	880,787
2028_09	839,619	838,043
2028_10	494,575	501,596
2028_11	318,043	319,564
2028_12	85,519	117,849
2029_01	64,279	149,291
2029_02	251,421	278,701
2029_03	124,769	148,835
2029_04	572,803	576,336
2029_05	280,894	315,266
2029_06	626,341	629,795
2029_07	1,039,461	1,040,396
2029_08	920,127	932,323
2029_09	652,924	650,727
2029_10	512,801	511,087
2029_11	334,608	333,465
2029_12	386,277	386,288
2030_01	93,308	465,801
2030_02	258,941	301,309
2030_03	343,068	375,241
2030_04	731,037	731,674
2030_05	494,732	570,098
2030_06	531,532	535,972
2030_07	1,168,147	1,171,880
2030_08	1,180,785	1,179,380
2030_09	864,136	904,934
2030_10	651,879	652,328
2030_11	498,127	502,709
2030_12	642,927	648,290
2031_01	200,099	288,912
2031_02	310,073	357,162
2031_03	235,505	276,373
2031_04	254,682	257,491
2031_05	357,063	368,038
2031_06	971,000	970,297
2031_07	1,282,578	1,282,155
2031_08	1,206,788	1,216,307
2031_09	890,368	962,689

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2031_10	349,662	395,097
2031_11	796,190	793,535
2031_12	562,500	560,579
2032_01	106,303	166,659
2032_02		301,710
2032_03	96,917	96,586
2032_04	136,568	136,102
2032_05	217,771	224,385
2032_06	867,948	868,971
2032_07	932,898	934,919
2032_08	992,881	989,581
2032_09	585,286	585,901
2032_10	405,402	410,189
2032_11	372,466	371,194
2032_12	445,173	443,690
2033_01	161,554	258,481
2033_02		
2033_03	222,067	227,003
2033_04	27,683	27,588
2033_05	147,642	148,977
2033_06	690,307	728,468
2033_07	1,021,483	1,079,715
2033_08	1,304,335	1,313,214
2033_09	320,897	321,110
2033_10	215,326	220,863
2033_11	288,851	304,910
2033_12	152,027	155,296
2034_01	288,949	374,723
2034_02		64,003
2034_03		
2034_04	162,712	164,011
2034_05	164,251	163,690
2034_06	509,140	518,226
2034_07	957,510	975,438
2034_08	804,373	825,765
2034_09	289,747	290,596
2034_10	207,137	206,429
2034_11	316,087	316,932
2034_12	521,732	521,267
2035_01	127,014	122,972
2035_02	43,726	43,513
2035_03	104,410	104,053
2035_04		
2035_05		
2035_06	84,805	84,516
2035_07	362,965	392,054
2035_08	356,773	372,734

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2035_09	143,801	187,029
2035_10	17,085	17,027
2035_11	34,170	71,633
2035_12	53,154	52,973
2036_01		
2036_02		
2036_03		
2036_04		
2036_05		
2036_06	75,509	75,251
2036_07	274,410	273,473
2036_08	212,098	213,224
2036_09		
2036_10	60,684	60,477
2036_11	32,238	32,128
2036_12		
2037_01		
2037_02	211,941	224,664
2037_03		
2037_04		
2037_05		
2037_06	99,347	99,007
2037_07	185,815	185,181
2037_08	150,860	170,513
2037_09	22,077	22,002
2037_10		
2037_11		
2037_12		
2038_01		
2038_02		
2038_03		
2038_04		
2038_05		
2038_06	71,544	71,306
2038_07	123,135	122,714
2038_08	86,378	86,083
2038_09	38,594	38,463
2038_10		
2038_11		
2038_12		
2039_01		
2039_02	80,093	131,165
2039_03		
2039_04		
2039_05		
2039_06	20,195	20,126
2039_07	67,929	67,697

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2039_08	18,359	18,296
2039_09	20,195	20,126
2039_10		
2039_11		
2039_12		
2040_01		
2040_02		
2040_03		
2040_04		
2040_05		
2040_06		
2040_07		
2040_08		
2040_09		
2040_10		
2040_11		
2040_12	635,188	633,019

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Month	Zeeland 1A	Zeeland 1B
2024_01	1,217,164	1,253,564
2024_02	1,175,304	1,171,299
2024_03	1,221,558	1,218,619
2024_04	1,129,407	1,127,894
2024_05	1,185,628	1,188,679
2024_06	943,604	937,750
2024_07	858,851	852,755
2024_08	1,002,492	1,006,005
2024_09	809,464	838,193
2024_10	667,092	697,226
2024_11	584,299	584,663
2024_12	173,089	184,229
2025_01	345,138	346,307
2025_02	312,534	311,469
2025_03	334,217	361,142
2025_04	527,006	525,223
2025_05	306,189	384,673
2025_06	637,872	637,315
2025_07	815,950	818,198
2025_08	967,460	1,039,410
2025_09	271,115	268,563
2025_10	219,252	218,503
2025_11	295,427	322,483
2025_12	126,492	126,060
2026_01	261,975	263,426
2026_02	30,358	30,254
2026_03		
2026_04	319,802	322,713
2026_05	354,176	352,967
2026_06	378,611	375,043
2026_07	648,367	672,790
2026_08	576,478	605,594
2026_09	196,824	196,463
2026_10	212,506	213,461
2026_11	161,266	160,720
2026_12	172,029	171,441
2027_01	75,895	75,636
2027_02	66,297	66,073
2027_03	152,713	153,360
2027_04	375,981	375,861
2027_05	210,819	215,142
2027_06	408,313	407,453
2027_07	811,670	807,991
2027_08	872,128	866,885
2027_09	397,978	398,747
2027_10	456,050	470,049

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2027_11	318,396	318,485
2027_12	94,326	94,010
2028_01		
2028_02	43,729	43,586
2028_03	28,671	28,574
2028_04	513,234	511,484
2028_05	236,798	237,692
2028_06	618,966	616,191
2028_07	672,794	690,949
2028_08	497,223	492,589
2028_09	364,984	364,545
2028_10	339,398	341,087
2028_11	244,951	247,484
2028_12		
2029_01	79,790	82,881
2029_02	210,176	209,463
2029_03	101,715	103,051
2029_04	355,863	354,648
2029_05	168,655	168,080
2029_06	360,335	357,963
2029_07	740,300	734,903
2029_08	646,275	640,250
2029_09	498,793	494,096
2029_10	358,631	357,436
2029_11	266,476	267,246
2029_12	257,922	257,047
2030_01	170,342	169,760
2030_02	210,055	212,187
2030_03	60,716	60,509
2030_04	415,331	419,510
2030_05	427,099	437,821
2030_06	361,379	359,000
2030_07	918,640	938,281
2030_08	853,175	849,116
2030_09	569,374	566,537
2030_10	508,651	508,656
2030_11	325,543	391,574
2030_12	439,828	477,002
2031_01	187,017	186,380
2031_02	314,490	313,457
2031_03	140,717	140,236
2031_04	55,948	57,446
2031_05	171,234	237,887
2031_06	718,988	714,751
2031_07	856,436	851,361
2031_08	803,064	799,468
2031_09	460,992	520,568

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2031_10	130,545	131,788
2031_11	578,567	576,625
2031_12	337,784	336,639
2032_01	139,021	140,236
2032_02	128,849	128,409
2032_03	57,643	57,446
2032_04	57,643	57,446
2032_05	88,160	87,859
2032_06	461,985	461,651
2032_07	685,605	683,721
2032_08	672,908	670,567
2032_09	293,841	320,819
2032_10	175,552	174,962
2032_11	231,621	232,524
2032_12	315,014	315,147
2033_01	130,301	156,902
2033_02		
2033_03	133,167	133,887
2033_04		
2033_05	106,809	133,478
2033_06	362,117	360,709
2033_07	586,053	603,599
2033_08	567,425	591,660
2033_09	247,238	244,919
2033_10	72,902	99,686
2033_11	155,610	157,426
2033_12	132,240	133,478
2034_01	294,510	294,693
2034_02		
2034_03		
2034_04	83,477	90,892
2034_05	81,378	81,101
2034_06	259,361	258,430
2034_07	564,537	570,782
2034_08	467,448	478,649
2034_09	194,810	194,476
2034_10	120,372	119,961
2034_11	238,965	238,181
2034_12	435,873	451,301
2035_01	105,004	106,334
2035_02	35,566	35,445
2035_03	89,762	89,455
2035_04		
2035_05		
2035_06		
2035_07	204,146	203,245
2035_08	166,925	170,406

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2035_09	62,335	61,746
2035_10	15,243	15,191
2035_11		
2035_12	25,404	25,318
2036_01		
2036_02		
2036_03		
2036_04		
2036_05		
2036_06	15,188	16,549
2036_07	191,367	191,062
2036_08	145,803	144,425
2036_09		
2036_10	27,070	26,977
2036_11	28,761	28,663
2036_12		
2037_01		
2037_02	199,430	198,749
2037_03		
2037_04		
2037_05		
2037_06	19,724	19,537
2037_07	91,032	90,171
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Consumers Energy Count on Us®

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		

Docusign Envelope ID: F106A1E0-5C65-43AA-ABB9-8A3B4CAC0BFD

Consumers Energy Count on Us®

Concept Approval

Jackson Generating Station Generator Step-Up transformer replacement.

Date: 11/14/2024

Prepared by: Paul Ohep

Figure 1. Jackson Generating Station.

Docusign Envelope ID: F106A1E0-5C65-43AA-ABB9-8A3B4CAC0BFD

Executive Summary

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 vulnerability, meaning that a failure of any GSU could result in a significant loss of power generation, ranging from 47 MW to 104 MW. The lead time for procuring a new GSU is up to 3 years due to custom-built specifications and specialized material requirements, creating substantial operational risks. 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. As the GSUs have reached the industry life expectancy of 20 years, the likelihood of failure grows, raising serious concerns about operational reliability and financial impacts.

Consumers Energy's existing spare transformers at other facilities do not meet the specific voltage and configuration requirements for JGS, and efforts to secure a short-term lease agreement with Midland Cogeneration Venture (MCV) failed in 2024, leaving JGS without an immediate backup solution. This has escalated the need for a dedicated spare GSU on-site to mitigate the risk of prolonged derates and financial losses.

Alternative Solutions Considered:

1. **Do Nothing**: This option involves accepting the risks associated with not having a spare GSU. While avoiding immediate expenditure, it poses severe operational and financial risks, including potential losses of $49.3 million due to extended derates and lost capacity and energy value. The failure of a GSU would lead to a 1080-day 104MW derate, resulting in a direct loss of $28 million in capacity value due to MISO's multi-year accreditation impact and $21.3 million in energy value losses. This approach carries the highest long-term cost and risk, threatening reliability, safety, and financial stability.
2. **Lease a Spare Transformer and Overhaul Failed GSU**: This alternative involves renting a GSU and overhauling the failed unit if repairable, at an estimated cost of $10.8 million plus substantial ongoing rental fees. However, no available transformers currently meet JGS's specifications, making this option unviable. The financial and operational risks associated with unplanned outages, including an estimated $7.4 million in capacity and energy losses, further render this approach unfavorable compared to owning a dedicated spare.
3. **Procure and Store a Spare GSU On-Site**: Purchasing a spare GSU and installing a storage area at JGS is the most reliable, cost-effective, and strategic solution. At an estimated cost of $5 million, this option ensures immediate access to a spare GSU, significantly reducing downtime and avoiding the extended lead times associated with new procurement. It eliminates dependency on external agreements, mitigates substantial future costs, and addresses the industry-wide shortage of GSUs, safeguarding JGS's operational continuity.

Conclusion: The procurement and on-site storage of a spare GSU at JGS is a prudent investment that ensures long-term operational reliability, financial stability, and reduced risk exposure. It provides a proactive and predictable solution to GSU failures, avoiding the severe consequences of extended outages and market disruptions.

Docusign Envelope ID: F106A1E0-5C65-43AA-ABB9-8A3B4CAC0BFD

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$5,000,000

Proposed Start Implementation Year

First year spend: 2025

Delivery year: 2027

Docusign Envelope ID: F106A1E0-5C65-43AA-ABB9-8A3B4CAC0BFD

Problem Description

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.

Figure 2. Typical Step-Up transformer

Docusign Envelope ID: F106A1E0-5C65-43AA-ABB9-8A3B4CAC0BFD

Alternative Solutions/Alternatives Considered

1. Do Nothing – Cost: $54.1 million ($5M for new GSU plus $49.3M in energy value and potential capacity lost)

Overview

The “Do Nothing” approach involves continuing to operate without procuring a spare GSU transformer for the Jackson Generating Station (JGS), essentially accepting the substantial risks associated with a potential GSU failure. While this option avoids any immediate capital expenditure, it exposes JGS to significant operational, financial, and safety risks. The GSU transformer is a critical piece of infrastructure that steps up the voltage from the generator to the grid, and a failure would result in a severe operational disruption.

When the GSU is under load, a failure would lead to an immediate and significant derate, reducing the station’s output by up to 104 MW, depending on the generator configuration. This not only disrupts the plant’s generation capabilities but also risks collateral damage to other critical equipment, such as the generator itself or the high-voltage output breaker, further compounding the operational and financial impact.

The timeline for replacing or refurbishing a GSU transformer after it fails is of significant importance. Due to the specialized design of GSUs, securing a replacement can take up to 3 years, as indicated by recent transformer projects and consultations with suppliers. This prolonged downtime would severely affect the station’s ability to generate power and revenue, triggering multi-year financial impacts due to MISO’s capacity accreditation rules.

Financial Impacts of Doing Nothing

1. **Capacity Value Potential Loss - $28 Million**
   A significant financial risk posed by a GSU failure without a spare is the loss of capacity value as determined by MISO. MISO accredits capacity based on a rolling three-year historical average of Zonal Resource Credits (ZRCs). Any forced outage exceeding 30 days can affect this calculation, leading to a reduction in the station's ZRCs for multiple years.

   Assumption: For this scenario, we will assume that the unit will not be offered into the capacity market, thus avoiding the need to incur replacement charges. This means that only the capacity value itself will be affected, with no additional costs for replacement capacity.

   Based on a 75% CONE (Cost of New Entry) value of $127,135, the projected capacity value loss over the three-year period is estimated at $28 million. This figure accounts for the reduction in ZRCs over three years due to the prolonged derate and the impact on capacity accreditation. The $28 million loss is a direct result of JGS being unable to contribute its full capacity to the MISO market during this derate period, resulting in lower capacity payments. The table below summarizes the capacity losses forecasted.

Docusign Envelope ID: F106A1E0-5C65-43AA-ABB9-8A3B4CAC0BFD

	Planned (No exemption) /Forced outage (no replacement charges)					
	2023	2024	2025	2026	2027	2028
Planned Capacity (ZRCs)	525	525	525	525	525	525
Lost Capacity (ZRCs)	0	0.0	97.9	97.9	97.9	0
Delta Capacity (ZRCs)	525	525.0	427.1	427.1	427.1	525
Loss Capacity Revenue			$ 9,336,110	$ 9,336,110	$ 9,336,110	$ -
Total						$ 28,008,331

Table 1. capacity losses for 1080-day derate of 104MW

2. **Energy Value Estimated Loss - $21.3 Million**
   In addition to the loss of capacity value, JGS would also experience a significant loss in energy value due to its inability to generate power during the extended derate. The Net Energy Value (NEV) for the station, which is the measure of gross energy value minus total operating costs, is estimated at $21.3 million for the 1080-day period. Table 2 below shows the details of the NEV losses.

Net Present Value Results	1080 Day Derate
Current Nameplate Capacity (MW)	547
Upgraded Capacity (MW)	547
Derate Magnitude (MW)	104
Incremental Energy(K$)	($79,392)
Incremental Operating Costs (K$)	$58,142
Total Value of Energy losses (K$)	($21,251)

Table 2. Net energy value losses for 1080-day 104MW derate

Overall Economic Impact

The total estimated financial impact of not having a spare GSU on-site is $49.3 million, consisting of $28 million in lost capacity value and $21.3 million in lost energy value over a 1080-day derate period. These losses do not account for any potential collateral damage to other equipment, increased repair costs, or safety hazards that may arise from the failure of the GSU transformer under load.

Advantages and Disadvantages

Advantages:

- **No Immediate Expenditure**: There is no upfront capital cost for purchasing a spare transformer, nor is there a need to build and maintain storage facilities. This option conserves immediate financial resources that could be allocated elsewhere in the short term.
- **No Storage Requirements**: Without the need for a spare, the costs associated with preparing and maintaining a dedicated storage area for a spare GSU are avoided.

Disadvantages:

- **High Financial Risk**: This approach carries the highest potential cost in the long term. A GSU failure would lead to substantial financial losses from both lost capacity value and lost energy production, totaling an estimated $49.3 million.
- **Extended Downtime**: The lead time for procuring a replacement GSU can take up to 3 years, resulting in an extended derate that severely impacts both capacity and energy revenue. The risk of additional equipment damage during the failure could further prolong downtime and increase repair costs.
- **Reduced Reliability**: By not having a spare GSU on-site, JGS remains vulnerable to unplanned derates, which could lead to increased costs in purchasing replacement power, fines for unfulfilled contracts, or additional costs associated with renting a temporary transformer (if available).
- **MISO Accreditation Impact**: Any outage exceeding 30 days would trigger a multi-year financial impact due to MISO's rolling three-year average capacity accreditation. The loss of Zonal Resource Credits (ZRCs) would affect JGS's capacity value for several years following the outage.
- **Operational and Safety Risks**: The failure of a GSU transformer could have cascading effects, damaging other critical components like the generator or high-voltage breakers. This introduces significant operational risks, along with potential safety hazards for personnel and equipment.

Situations Where This Option Might Be Viable

While the “Do Nothing” approach poses significant risks, it may be a viable option in very specific circumstances:

1. **Low Probability of Failure**: If the likelihood of a GSU failure is extremely low, and the plant can operate without major incidents for a prolonged period, this option could avoid unnecessary upfront capital expenditure.
2. **Limited Unit Usage**: If the impacted generator unit is not critical to grid reliability or customer demand, and JGS can continue operations with reduced output, the financial risk of a GSU failure may be deemed acceptable.
3. **No Immediate Spare Needed**: If the plant does not need to run continuously, and a GSU failure would not significantly disrupt Consumers Energy’s ability to meet customer demand or MISO commitments, delaying the purchase of a spare transformer might be an acceptable temporary strategy.

Conclusion

The “Do Nothing” approach represents a high-risk strategy with potentially severe financial and operational consequences for the Jackson Generating Station. While it avoids immediate capital expenditure, the long-term costs associated with lost capacity value, lost energy revenue, and extended downtime far outweigh the short-term savings. Given the critical nature of the GSU transformer and the extended lead time for replacement, this option exposes JGS to substantial risks that could jeopardize operational reliability and financial stability over the long term.

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2. Lease a Spare Transformer, Overhaul the Failed GSU (If Repairable) -$10.8M plus $7.4M in energy and potential capacity losses plus $4.8M/yr in rental fees for subsequent years.

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.

This option would result in significant losses on both Net Energy Value and Capacity value. The losses are broken down as follows:

- **Net Energy Value losses - $3.1M:** A 90-day 104MW derate at Jackson Generating station is estimated to result in a net energy value (NEV) loss of $3.1 million. The calculation assumes a worst-case scenario, as such an extended derate that would result from an unplanned failure rather than scheduled maintenance. Table 3 bellow summarizes the energy revenue losses.

Net Present Value Results	90 Day derate
Current Nameplate Capacity (MW)	547
Upgraded Capacity (MW)	547
Derate Magnitude (MW)	104
Incremental Energy(K$)	($8,809)
Incremental Operating Costs (K$)	$5,694
Total Value of Energy Losses (K$)	**($3,115)**

Table 3. Energy revenue and costs for a 104MW derate

- **Potential Capacity losses - $4.3M:** If there is a unit derate of 104MW for 90 days, the estimated potential capacity losses are $4.3 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 521.5 Zonal Resource Credits (ZRCs) for the Jackson station, the loss capacity values are as follows:

	Planned (No exemption) /Forced outage					
	2023	2024	2025	2026	2027	2028
Planned Capacity (ZRCs)	521.5	521.5	521.5	521.5	521.5	521.5
Lost Capacity (ZRCs)	0	8.1	8.1	8.1	0	0
Delta Capacity (ZRCs)	521.5	513.4	513.4	513.4	521.5	521.5
Loss Capacity Revenue	$ 2,026,512	$ 772,822	$ 772,822	$ 772,822	$ -	$ -
Total						$ 4,344,980

Table 4. potential capacity losses for 90-day derate of 104 MW with capacity purchase included.

5. This estimation assumes the need to replace capacity during a forced derate to avoid future accreditation impacts (no three-year penalty), valuing capacity at 75% of CONE.

Situations Where This Could Be Viable

This option could be considered viable under two scenarios:

1. **Infrequent or Low-Usage Units**: If a failure occurs on a unit that is not critical to operations or can remain offline for an extended period without significant impact, procuring and installing a rental GSU and overhauling the failed GSU could be a suitable option.
2. **Limited Availability of Capital for Purchasing**: In situations where capital for purchasing a new spare GSU is not available or where short-term financial constraints exist, leasing a GSU may offer a temporary solution while awaiting a permanent fix.

Neither of these two options are viable options for this situation.

Conclusion

While leasing a spare transformer and overhauling the failed unit offers a potential solution for other types of equipment, it is not viable for JGS due to the specific voltage and configuration requirements. Additionally, the financial and operational risks associated with unplanned derates, including capacity and energy losses, make this a less favorable option compared to purchasing a dedicated spare GSU.

3. Procure and Store a Spare GSU on-site - Cost: $5M

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.

Several key factors support the selection of this option:

1. **Immediate Availability**: Having a spare GSU stored on-site ensures that JGS can rapidly respond to a transformer failure or planned overhaul without the extended lead times required for procuring new transformers, which can take up to 3 years due to custom specifications and material availability. This minimizes operational downtime and helps maintain system reliability.
2. **Eliminates Dependency on External Agreements**: Originally, a short-term solution was pursued through an O&M-funded lease agreement with Midland Cogeneration Venture (MCV) to provide access to their spare GSU if needed. However, an agreement with MCV could not be reached, leaving JGS without a viable leasing option. Additionally, there are no identified transformers available currently that meet JGS's specific voltage (138kV-13.2kV-13.2kV) and winding configuration (WYE-DELTA) requirements. As a result, procuring a dedicated spare GSU for JGS is the only reliable long-term solution, as relying on external sources has proven unfeasible.
3. **Cost Savings**: Once the spare GSU is procured and stored on-site, Consumers Energy can terminate the O&M lease agreement with MCV, which incurs a recurring cost of $60,000 per year. This saves ongoing operational expenses for the remainder of the plant's life. Additionally, the availability of an on-site spare GSU eliminates the need for expensive emergency rental agreements or replacement power costs, which have proven to be a significant financial burden in the past.
4. **Industry-Wide GSU Shortage**: The global shortage of GSU transformers, combined with their high cost and long lead times, makes it imperative to have a dedicated spare on hand. Transformers of this size are typically custom-built, making it difficult to source replacements quickly. By securing a spare unit, Consumers Energy is proactively mitigating the risks associated with this shortage, ensuring the continued reliability of JGS.

Benefits Over Other Alternatives

- **Compared to Leasing a GSU**: Leasing a GSU from a third party, such as MCV, is unreliable due to the conditions of the agreement, which allow MCV to deny the request for their spare unit at any time. This option also incurs ongoing O&M costs, which would be eliminated by owning a spare transformer. Moreover, a dedicated spare provides immediate access, ensuring that JGS can restore operations without delays caused by third-party negotiations or availability issues.

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- **Compared to "Do Nothing"**: Waiting until a GSU failure occurs to address the situation is highly risky. In the event of a failure, the lack of an immediate spare would result in extended derates, costly rental agreements, and significant financial losses from lost generation capacity.

Conclusion

The decision to procure and store a spare GSU at JGS is a strategic investment that ensures the facility's long-term operational reliability and financial stability. It provides a readily available solution in the event of a GSU failure or overhaul, reduces dependence on external parties, and mitigates significant future costs associated with transformer lead times, rental agreements, and lost generation capacity.

Docusign Envelope ID: F106A1E0-5C65-43AA-ABB9-8A3B4CAC0BFD

Scope of Work

The aim of this project is to ensure continuous operation at the Jackson generating 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 Jackson station. 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: First year spend 2025, 2027 delivery.
- 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 Jackson 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

Docusign Envelope ID: F106A1E0-5C65-43AA-ABB9-8A3B4CAC0BFD

Conceptual Estimate

Year	Loaded Cost	Description
2025	**$500,000**	Request for Purchase work, Engineering work, Initial PO creation and initial percent payment (10% estimated)
2026	**$2,500,000**	Manufacturing percent payments, engineering and quality manufacturing visits, storage pad design.
2027	**$2,000,000**	Final manufacturing payments, engineering and manufacturing visits, storage pad material procurement and installation, GSU delivery, Closeout and project finality costs

Total Cost: $5,000,000

Asset Strategy Approval Comments

The Asset Strategy Group strongly recommends approval, given the challenges currently faced at the Jackson Station and the extended lead times for transformers. Ensuring that our key capacity plants have a spare GSU on hand is of utmost importance.

This Project **is** included in the 2024 electric rate case.

Docusign Envelope ID: F106A1E0-5C65-43AA-ABB9-8A3B4CAC0BFD

Approvals

Title	Approver Name	Date
Generation Planning Manager	Signed by: Cornelius Thompson Jr F6F211CF147C460...	11/18/2024 | 3:40 PM EST
Director of Generation Asset Strategy	DocuSigned by: Scott Argo 31EC7A87F8F34C6...	11/18/2024 | 12:01 PM EST
Exec Director of Electric Supply Engineering	Signed by: Richard T. Blumenstock C3E2F0B9920949B...	L/2024 | 4:21 AM EST
VP of Electric Supply	Signed by: Srikanth Maddipati 67DA622787D2488...	2/11/2024 | 9:48 PM EST

Concept Approval

Covert Station Static Frequency Converter Replacement

Date: 6/15/2024

Prepared by: Paul Ohep

Figure 1. Covert Generating Station

Executive Summary

Financial Summary

Funding Type: Capital
Estimated Total Cost: $4,466,000

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 buswork 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: $4,466,000 (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 $4,466,000 (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 SFC systems 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	**$0**	Generation Planning places retrieves quote and places PO for very long lead time parts.
2025	**$4000**	EPM starts drawing engineering, outage scheduling, and labor PO.
2026	**$4,462,000**	Parts receipt, construction, and closeout.

Total Cost: $ 4,466,000

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		

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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.

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

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

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

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

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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).

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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.

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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).

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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.

Average energy value estimated loss – $4.1M:

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.

On-site spare overall advantages and disadvantages:

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.

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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-

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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

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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:

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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:

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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.

<u>Average energy value estimated loss - $13.2M:</u>

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

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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.

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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.

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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

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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.

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Approvals

Title	Approver Name	Date
Generation Planning Manager John D Slinkard	DocuSigned by: John D Slinkard D640D95639854BE...	1/9/2024 | 7:55 AM EST
Director of Generation Asset Strategy Scott Hugo	DocuSigned by: Scott Hugo 31EC7A87F8F34C6...	1/8/2024 | 9:46 AM EST
Exec Director of Electric Planning Richard T. Blumenstock	DocuSigned by: Richard T. Blumenstock C3E2F0B9920949B...	10/2024 | 9:16 AM EST
VP of Electric Grid Integration Srikanth Maddipati	DocuSigned by: Srikanth Maddipati 67DA622787D2488...	1/10/2024 | 10:00 AM EST

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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

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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)

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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.

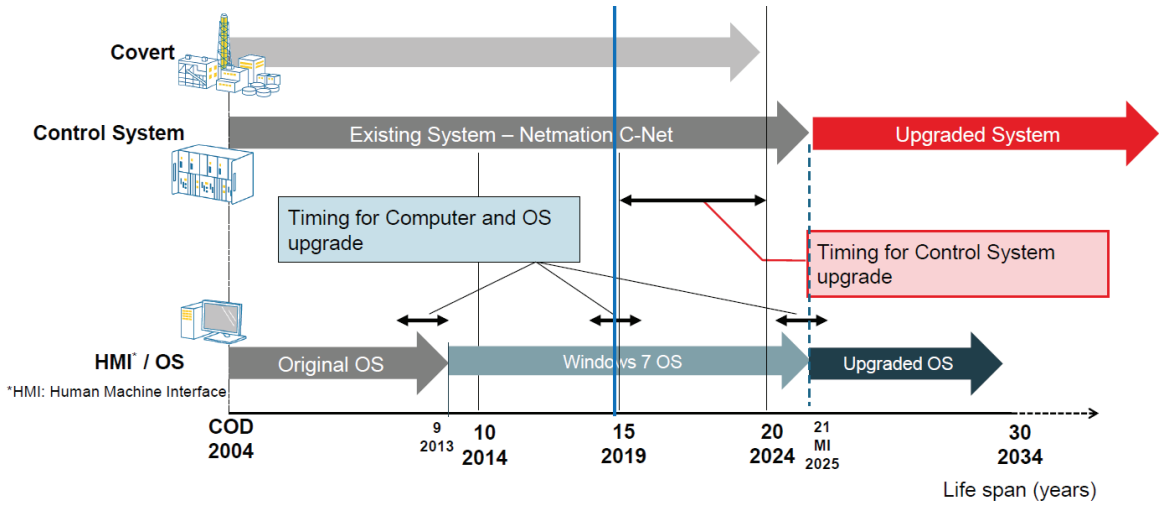

Figure 2 – Covert Netmation Control System Timeline

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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.

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- **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**.**

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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.

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- **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.

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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.

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- 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.

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- 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.

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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.

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- 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.

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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.

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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.

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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

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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

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Approvals

Title	Approver Name	Date
Generation Planning Manager John D Slinkard	DocuSigned by: John D Slinkard D640D95639854BE...	6/19/2024 | 12:26 PM EDT
Director of Generation Asset Strategy Scott Hugo	DocuSigned by: Scott Hugo 31EC7A87F8F34C6...	6/19/2024 | 10:16 AM EDT
Exec Director of Electric Supply Engineering Richard T. Blumenstock	DocuSigned by: Richard T. Blumenstock C3E2F0B9920949B...	6/19/2024 | 12:47 PM EDT
VP of Electric Supply Srikanth Maddipati	DocuSigned by: Srikanth Maddipati 67DA622787D2488...	7/31/2024 | 12:42 AM EDT

Consumers Energy Count on Us®

Concept Approval

Covert station DCS Evergreen Upgrade

Date: 1/30/2024

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 investment **is NOT** included in the current electric rate case.

Key terms to note about electric rate case:

1. Inclusion in Rate Case: The rate case typically encompasses the Capital component of projects planned for the bridge year (the year of filing, which is 2023 in this scenario) and the test year (usually the following year, in this case, 2024).

2. Capital vs. Cost of Removal (COR): Only the capital portion of a project is reflected in the rate case. The Cost of Removal (COR), on the other hand, is not included as these expenditures are covered in the Depreciation Rate Case, filed approximately every 3-5 years.

3. Impact on Projects with Mixed Costs: For projects that entail both capital and COR components, only the capital aspect appears in the rate case. Any project that is entirely COR-focused does not feature in the rate case; for instance, landfill closures are not included.

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

Docusign Envelope ID: 03B3A894-68C9-4347-A307-D20C47324D10

Consumers Energy Count on Us®

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.

Docusign Envelope ID: 03B3A894-68C9-4347-A307-D20C47324D10

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

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		

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Estimated Electric Rate Case PSCR Factor
May 2026 - April 2027

Case No.: U-21870
Exhibit No.: A-52 (EMB-6)
Page: 1 of 1
Witness: EMBreuring
Date: June 2025

Line No.	Description		(a) Total Company
	Expenses ($000)		
1	System Power Supply Costs	(1)	$ 1,681,379
2	2024 Under-Recovery PSCR	(2)	-
3	Transmission & Market Administrative Expense	(3)	631,863
4	PSCR Expenses		$ 2,313,242
	PSCR Revenue Contributions ($000)		
5	Intersystem Sales Revenue	(4)	$ 24,609
6	Self-Generation	(6)	15,603
7	GI-2		-
8	Base Jurisdictional PSCR x $0.05975		1,804,054
9	Base Non-Jurisdictional PSCR x $0.06010		-
10	Long-Term Industrial Load Retention Rate/LED	(5)	184,681
11	Wholesale Fuel Revenue		-
12	PSCR Revenue Contributions		$ 2,028,947
13	PSCR (Over)/Under Recovery		$ 284,295
	Electric Deliveries (MWh)		
14	Jurisdictional Bundled Deliveries	(7)	33,128,467
15	Less: Self-Generation	(8)	(173,301)
16	Less: GI-2		-
17	Less: Long-Term Industrial Load Retention Rate		(2,762,357)
18	Total Bundled PSCR Deliveries		30,192,808
	Estimated Jurisdictional PSCR Factor		
19	PSCR (Over)/Under Recovery ($000)		$ 284,295
20	Total Bundled PSCR Deliveries (MWh)		30,192,808
21	Total Jurisdictional PSCR Factor ($ per kWh)		**$ 0.00941**
	Estimated PSCR Recovery		
22	PSCR Revenue Contributions		$ 2,028,947
23	Plus: PSCR (Over)/Under Recovery		284,114
24	Non-jurisdictional PSCR Factor Contribution		-
25	Total PSCR Revenues		$ 2,313,061
26	Total PSCR (Over)/Under Recovery		$ 181

Total Losses	0.0678
Less: Transmission	0.0000
System Losses	0.0678
System Efficiency	1.07273
PSCR Base @ Gen	0.05570
System Efficiency	1.07273
PSCR Base @ Del	**0.05975**

Notes:
(1) Exhibit A-160 (MLM-1), page 1, line 42; plus page 3, line 64; less page 1, line 35.
(2) N/A
(3) Exhibit A-160 (MLM-1), page 1, line 35.
(4) Exhibit A-160 (MLM-1), page 3, line 64.
(5) Exhibit A-160 (MLM-1), page 1, line 43 and 44.
(6) Self-Generation PSCR Revenue from WP-LMC-15

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Customer Experience, Customer Operations
($000)

Case No.: U-21780
Corrected Exhibit No.: A-52 (JRB-2)
Page: 1 of 4
Witness: JRByrom
Date: September 2025

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2024	(c) Projected 12-Mos Ending 4/30/2027
1	Billing & Payment	10,176	11,505
	Labor	2,494	2,657
	Material	685	784
	Contractor	1,365	1,616
	Non-Labor Overhead	-	-
	Non-Labor Other	5,632	6,448
2	Customer Interactions	20,951	23,454
	Labor	15,605	17,213
	Material	69	83
	Contractor	4,579	5,087
	Non-Labor Overhead	-	-
	Non-Labor Other	698	1,070
3	Total CXCO O&M Expenses	31,127	34,959
	Labor	18,099	19,870
	Material	754	868
	Contractor	5,944	6,703
	Non-Labor Overhead	-	-
	Non-Labor Other	6,330	7,517

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Customer Experience, Customer Operations: Billing & Payment
($000)

Case No.: U-21870
Corrected Exhibit No.: A-53 (JRB-2)
Page: 2 of 4
Witness: JRByrom
Date: September 2025

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2024	(c) Projected 12-Mos Ending 4/30/2027
1	Customer Billing	8,944	10,048
	Labor	1,995	2,093
	Material	685	785
	Contractor	627	717
	Non-Labor Overhead	-	-
	Non-Labor Other	5,637	6,453
2	Customer Payment Programs	1,232	1,457
	Labor	499	564
	Material	(0)	(0)
	Contractor	738	899
	Non-Labor Overhead	-	-
	Non-Labor Other	(5)	(5)
3	Total Billing & Payment O&M Expenses	10,176	11,505
	Labor	2,494	2,657
	Material	685	784
	Contractor	1,365	1,616
	Non-Labor Overhead	-	-
	Non-Labor Other	5,632	6,448

MICHIGAN PUBLIC SERVICE COMMISSION | Case No.: | U-21870
Consumers Energy Company | Corrected Exhibit No.: | A-53 (JRB-2)
Summary of Actual & Projected O&M Expenses | Page: | 3 of 4
Customer Experience, Customer Operations: Customer Interactions | Witness: | JRByrom
($000) | Date: | September 2025

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2024	(c) Projected 12-Mos Ending 4/30/2027
1	Analytics & Outreach	2,118	2,881
	Labor	1,856	2,135
	Material	3	4
	Contractor	374	542
	Non-Labor Overhead	-	-
	Non-Labor Other	(114)	199
2	Business Customer Care	1,579	1,817
	Labor	1,419	1,584
	Material	1	2
	Contractor	113	168
	Non-Labor Overhead	-	-
	Non-Labor Other	46	63
3	Credit & Assistance	2,433	2,883
	Labor	1,598	1,822
	Material	50	64
	Contractor	710	902
	Non-Labor Overhead	-	-
	Non-Labor Other	75	95
4	Customer Contact Center	13,913	14,535
	Labor	10,149	10,961
	Material	15	14
	Contractor	3,121	2,964
	Non-Labor Overhead	-	-
	Non-Labor Other	628	597
5	Digital Customer Operations	907	1,338
	Labor	583	712
	Material	0	0
	Contractor	261	510
	Non-Labor Overhead	-	-
	Non-Labor Other	63	115
6	Total Customer Interactions O&M Expenses	20,951	23,454
	Labor	15,605	17,213
	Material	69	83
	Contractor	4,579	5,087
	Non-Labor Overhead	-	-
	Non-Labor Other	698	1,070

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Customer Experience, Customer Operations
($000)

Case No.: U-21870
Corrected Exhibit No.: A-53 (JRB-2)
Page: 4 of 4
Witness: JRByrom
Date: September 2025

Line No.	(a) Description	(b) Actual 12 Mos Ended 12/31/2024	(c) Base O&M for Merit & Inflation 12 Mos Ended 12/31/2024	(d) Merit & Inflation 12 Mos Ending 12/31/2025	(e) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2025	(f) Merit & Inflation 12 Mos Ending 12/31/2026	(g) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2026	(h) Merit & Inflation 4 Mos Ending 4/30/2027	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending 4/30/2027
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	Billing & Payment	10,176	10,176	-	11,294	-	11,424	-	1,329	11,505
	Labor	2,494	2,494	-	2,768	-	2,799	-	163	2,657
	Material	685	685	-	760	-	769	-	99	784
	Contractor	1,365	1,365	-	1,515	-	1,532	-	251	1,616
	Non-Labor Overhead	-	-	-	-	-	-	-	-	-
	Non-Labor Other	5,632	5,632	-	6,251	-	6,323	-	815	6,448
2	Customer Interactions	20,951	20,951	-	22,635	-	23,004	-	2,503	23,454
	Labor	15,605	15,605	-	16,860	-	17,134	-	1,608	17,213
	Material	69	69	-	74	-	76	-	15	83
	Contractor	4,579	4,579	-	4,947	-	5,028	-	508	5,087
	Non-Labor Overhead	-	-	-	-	-	-	-	-	-
	Non-Labor Other	698	698	-	754	-	766	-	372	1,070
3	Total CXCO O&M Expenses	31,127	31,127	-	33,930	-	34,428	-	3,832	34,959
	Labor	18,099	18,099	-	19,627	-	19,934	-	1,772	19,870
	Material	754	754	-	835	-	845	-	114	868
	Contractor	5,944	5,944	-	6,462	-	6,560	-	759	6,703
	Non-Labor Overhead	-	-	-	-	-	-	-	-	-
	Non-Labor Other	6,330	6,330	-	7,005	-	7,089	-	1,187	7,517

Notes

	12-Mo Ending 2025	12-Mo Ending 2026	4-Mo Ending 2027
Annual inflation rates per Company witness Daly	0.0%	0.0%	0.0%
Number of months in the period	12	12	4
Pro-rated inflation rate	0.0%	0.0%	0.0%

Weadock BESS Project – Milestone Schedule

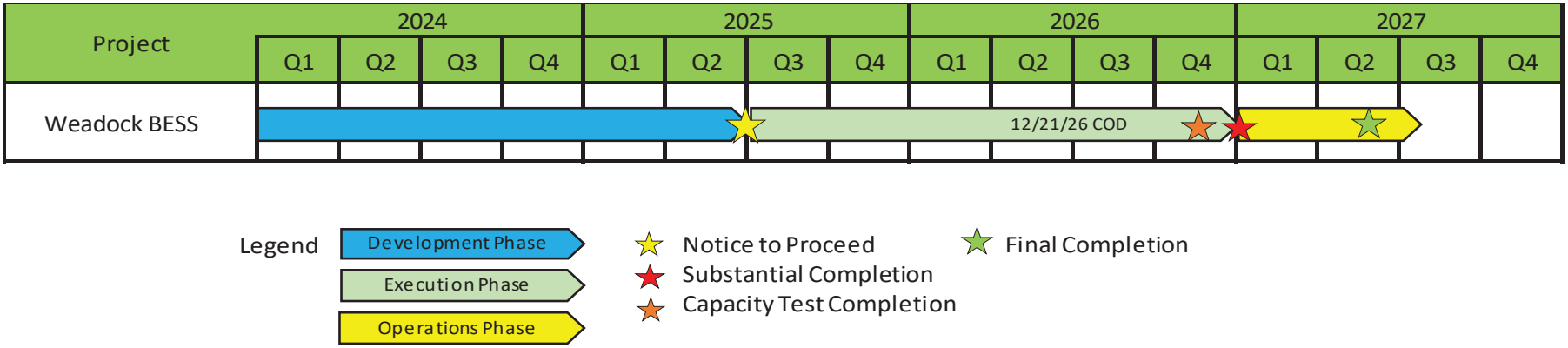

EXHIBIT A-55 (TPC-2)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-56 (TPC-3)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-57 (TPC-4)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-58 (TPC-5)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-59 (TPC-6)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

Iosco BESS Project – Milestone Schedule

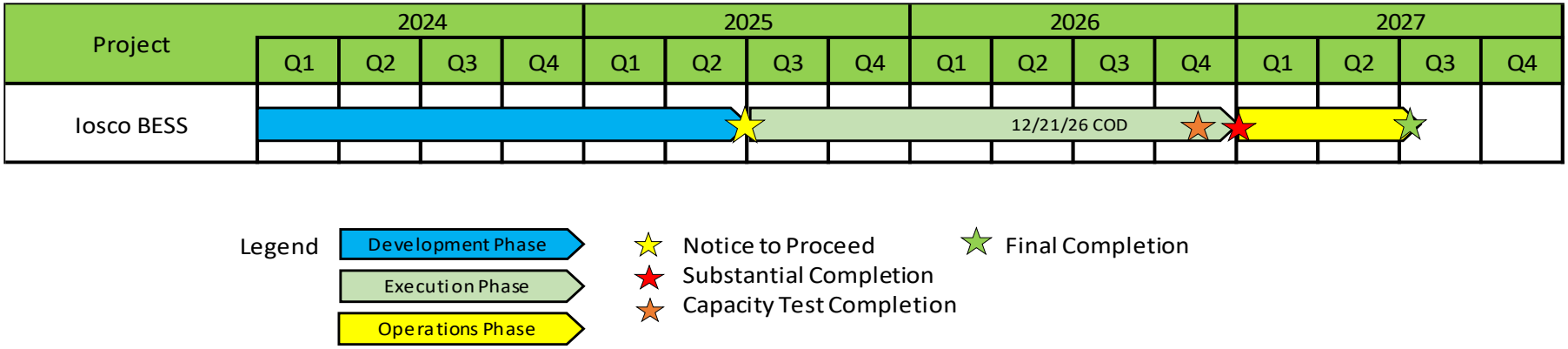

EXHIBIT A-61 (TPC-8)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-62 (TPC-9)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-63 (TPC-10)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-64 (TPC-11)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-65 (TPC-12)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response (DR) Surcharge

Case No.: U-21870
Exhibit No.: A-66 (LMC-5)
Page: 1 of 1
Witness: LMConnolly
Date: June 2025

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	0.002009	-	-	0.002009	per kWh
2	Smart Hours RSH	DR0001	0.002009	-	-	0.002009	per kWh
3	Night Time Savers RPM	DR0001	0.002009	-	-	0.002009	per kWh
4	Non-Transmitting Meters RSM	DR0001	0.002009	-	-	0.002009	per kWh
	Secondary Class						
5	Energy-only GS	DR0002	0.001831	-	-	0.001831	per kWh
6	Time-of-Use GSTU	DR0003	0.001831	-	-	0.001831	per kWh
7	Demand GSD	DR0004	0.61	-	-	0.61	per Peak kW
	Primary Class						
	Energy-only GP						
8	Voltage Level 1	DR0005	0.001553	-	-	0.001553	per kWh
9	Voltage Level 2	DR0006	0.001571	-	-	0.001571	per kWh
10	Voltage Level 3	DR0007	0.001587	-	-	0.001587	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	0.001375	-	-	0.001375	per kWh
15	Voltage Level 2	DR0012	0.001391	-	-	0.001391	per kWh
16	Voltage Level 3	DR0013	0.001405	-	-	0.001405	per kWh
	Energy Intensive EIP						
17	Voltage Level 1	DR0014	0.001144	-	-	0.001144	per kWh
18	Voltage Level 2	DR0015	0.001157	-	-	0.001157	per kWh
19	Voltage Level 3	DR0016	0.001169	-	-	0.001169	per kWh
	Lighting & Unmetered Class						
20	Metered Lighting GML	DR0017	0.000468	-	-	0.000468	per kWh
21	Universal Unmetered Lighting UUL	DR0018	0.000439	-	-	0.000439	per kWh
22	Unmetered GU	DR0019	0.001206	-	-	0.001206	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-21870
Exhibit No.: A-67 (LMC-6)
Page: 1 of 1
Witness: LMConnolly
Date: June 2025

Line No.	Description	Test-year Sales (MWh)	ERC Deferral [1] ($000)	ERC Deferral Surcharge ($ / kWh)
	FULL SERVICE			
1	Residential Class	12,685,410	$ 15,578	0.001228
	Secondary Class			
2	Energy-only GS	4,043,300	3,793	0.000938
3	Time-of-Use GSTU	83,093	78	0.000938
4	Demand GSD	2,927,804	2,117	0.000723
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,413	0	0.000117
6	Voltage Level 2	30,887	6	0.000180
7	Voltage Level 3	624,710	191	0.000306
	Demand GPD			
8	Voltage Level 1	1,158,158	91	0.000079
9	Voltage Level 2	1,441,363	174	0.000121
10	Voltage Level 3	2,395,375	496	0.000207
	Time-of-Use GPTU			
11	Voltage Level 1	461,269	36	0.000079
12	Voltage Level 2	493,168	60	0.000121
13	Voltage Level 3	3,289,071	681	0.000207
	Energy Intensive EIP			
14	Voltage Level 1	332,592	26	0.000079
15	Voltage Level 2	53,237	6	0.000121
16	Voltage Level 3	6,737	1	0.000207
	Lighting & Unmetered Class			
17	Metered Lighting GML	10,777	15	0.001395
18	Universal Unmetered Lighting UUL	54,640	329	0.006016
19	Unmetered GU	97,806	40	0.000404
	Self-generation Class			
20	Large Self-generation GSG-2			
21	Voltage Level 1	77,349	6	0.000079
22	Voltage Level 2	77,337	9	0.000121
23	Voltage Level 3	18,615	4	0.000207
24	Total Full Service		$ 23,738	

Line No.	Description	Test-year Sales (MWh)	ERC Deferral [1] ($000)	ERC Deferral Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001228
	Secondary Class			
2	Energy-only GS	18,386	17	0.000938
3	Time-of-Use GSTU	-	-	0.000938
4	Demand GSD	171,253	124	0.000723
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000117
6	Voltage Level 2	1,760	0	0.000180
7	Voltage Level 3	69,383	21	0.000306
	Demand GPD			
8	Voltage Level 1	1,265,948	100	0.000079
9	Voltage Level 2	1,076,272	130	0.000121
10	Voltage Level 3	949,620	197	0.000207
11	Total ROA Service		$ 589	
12	Total Surcharge Revenue Collected		$ 24,327	
13	Rounding		0	
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-21870
Exhibit No.: A-68 (LMC-7)
Page: 1 of 2
Witness: LMConnolly
Date: June 2025

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	$ 14,246	0.001123
	Secondary Class			
2	Energy-only GS	4,043,300	3,469	0.000858
3	Time-of-Use GSTU	83,093	71	0.000858
4	Demand GSD	2,927,804	1,935	0.000661
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,413	0	0.000107
6	Voltage Level 2	30,887	5	0.000164
7	Voltage Level 3	624,710	175	0.000280
	Demand GPD			
8	Voltage Level 1	1,158,158	83	0.000072
9	Voltage Level 2	1,441,363	160	0.000111
10	Voltage Level 3	2,395,375	450	0.000188
	Time-of-Use GPTU			
11	Voltage Level 1	461,269	33	0.000072
12	Voltage Level 2	493,168	55	0.000111
13	Voltage Level 3	3,289,071	618	0.000188
	Energy Intensive EIP			
14	Voltage Level 1	332,592	24	0.000072
15	Voltage Level 2	53,237	6	0.000111
16	Voltage Level 3	6,737	1	0.000188
	Lighting & Unmetered Class			
17	Metered Lighting GML	10,777	14	0.001276
18	Universal Unmetered Lighting UUL	54,640	301	0.005501
19	Unmetered GU	97,806	36	0.000369
	Self-generation Class			
20	Large Self-generation GSG-2			
21	Voltage Level 1	77,349	6	0.000072
22	Voltage Level 2	77,337	9	0.000111
23	Voltage Level 3	18,615	3	0.000188
24	Total Full Service		$ 21,701	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue [1] ($000)	(h) IRM Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.001123
	Secondary Class			
2	Energy-only GS	18,386	16	0.000858
3	Time-of-Use GSTU	-	-	0.000858
4	Demand GSD	171,253	113	0.000661
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000107
6	Voltage Level 2	1,760	0	0.000164
7	Voltage Level 3	69,383	19	0.000280
	Demand GPD			
8	Voltage Level 1	1,265,948	91	0.000072
9	Voltage Level 2	1,076,272	119	0.000111
10	Voltage Level 3	949,620	179	0.000188
11	Total ROA Service		$ 538	
12	Total Surcharge Revenue Collected		$ 22,239	
13	Rounding		5	
14	Total Surcharge Revenue Target		$ 22,244	

(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-21870
Exhibit No.: A-68 (LMC-7)
Page: 2 of 2
Witness: LMConnolly
Date: June 2025

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	$ 40,479	0.003191
	Secondary Class			
2	Energy-only GS	4,043,300	9,854	0.002437
3	Time-of-Use GSTU	83,093	202	0.002437
4	Demand GSD	2,927,804	5,498	0.001878
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	3,413	1	0.000304
6	Voltage Level 2	30,887	25	0.000796
7	Voltage Level 3	624,710	497	0.000796
	Demand GPD			
8	Voltage Level 1	1,158,158	210	0.000181
9	Voltage Level 2	1,441,363	683	0.000474
10	Voltage Level 3	2,395,375	1,135	0.000474
	Time-of-Use GPTU			
11	Voltage Level 1	461,269	83	0.000181
12	Voltage Level 2	493,168	234	0.000474
13	Voltage Level 3	3,289,071	1,559	0.000474
	Energy Intensive EIP			
14	Voltage Level 1	332,592	60	0.000181
15	Voltage Level 2	53,237	25	0.000474
16	Voltage Level 3	6,737	3	0.000474
	Lighting & Unmetered Class			
17	Metered Lighting GML	10,777	39	0.003625
18	Universal Unmetered Lighting UUL	54,640	854	0.015628
19	Unmetered GU	97,806	103	0.001049
	Self-generation Class			
20	Large Self-generation GSG-2			
21	Voltage Level 1	77,349	14	0.000181
22	Voltage Level 2	77,337	37	0.000474
23	Voltage Level 3	18,615	9	0.000474
24	Total Full Service		$ 61,605	

Line No.	(e) Description	(f) Test-year Sales (MWh)	(g) IRM Revenue [1] ($000)	(h) IRM Surcharge ($ / kWh)
	ROA SERVICE			
1	Residential Class	-	$ -	0.003191
	Secondary Class			
2	Energy-only GS	18,386	45	0.002437
3	Time-of-Use GSTU	-	-	0.002437
4	Demand GSD	171,253	322	0.001878
	Primary Class			
	Energy-only GP			
5	Voltage Level 1	-	-	0.000304
6	Voltage Level 2	1,760	1	0.000796
7	Voltage Level 3	69,383	55	0.000796
	Demand GPD			
8	Voltage Level 1	1,265,948	229	0.000181
9	Voltage Level 2	1,076,272	510	0.000474
10	Voltage Level 3	949,620	450	0.000474
11	Total ROA Service		$ 1,612	
12	Total Surcharge Revenue Collected		$ 63,217	
13	Rounding		(19)	
14	Total Surcharge Revenue Target		$ 63,199	

(1) A-89 (EAD-5)

EXHIBIT A-69 (LMC-8)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT A-70 (LMC-9)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC

OFFICER PLAN

Category	2024 MEASURE	Weighting
Safety	**Employee Safety** (Recordable Incident Rate & High-Risk Injuries (equally weighted) 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%**

2024 Plan Year

	50% Threshold	75%	100% Target	125%	150%	175% Max
Employee Safety	a.1.76	a.1.23	**a. 0.96**	a. 0.92	a. 0.86	a. 0.75
(Recordable Incidents Rate, High-Risk Injuries[1], & No fatalities[2])	b. 25	b.20	**b.13**	b.12	b.11	b. 10
Culture Index (Empowerment, Employee Engagement & DEI)	1 index at Target[3]	2 index at Target[3]	**All 3 indexes at Target[3]**	2 indexes at Target &1 Index above Target	1 index at Target & 2 Indexes above Target	3 Indexes above Target
Customer Experience (Survey Measuring CXi)	64	67	**69**	71	75	81
Electric Reliability (SAIDI in minutes)	185	180	**170**	160	155	150
Affordability[4] (O&M Savings through Waste Elimination)	$45M	$55M	**$63M**	$66M	$70M	$74M
Methane Emission (Reduction through replacement of mains and services)	278 MT	290 MT	**302 MT**	335 MT	366 MT	375 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 Target = 2023 Q4 actual +2 points (Averaged results from semi-annual employee survey).
4 The Company is not seeking recovery of this measure as it is financial in nature.

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%**

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.70 + 1	a.70 + 2	**a.**70 + 3	a.70 + 4	a.70 + 6	a.70 + 8
b. Empowerment (33%), &	b.64 + 1	b.64 + 2	**b.**64 + 3	b.64 + 4	b.64 + 6	b.64 + 8
c. Diversity, Equity, & Inclusion (33%)	c.72 + 1	c.72 + 2	**c.**72 + 3	c.72 + 4	c.72 + 6	c.72 + 8
(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.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Target Pay Level Market Analysis
Non-officer

Case No.: U-21870
Exhibit No.: A-72 (AMC-2)
Page: 1 of 1
Witness: AMConrad
Date: June 2025

Exempt Jobs:
2024 Market study

Job Family	# of Employees	Annual Salary	Market Data	Avg. Salary vs Market
ACCOUNTING	53	$ 121,501.53	$ 121,913.79	-0.3%
ACCOUNTS PAYABLE & RECEIVABLE	6	$ 105,804.00	$ 113,164.17	-6.5%
ADMINISTRATIVE SUPPORT	27	$ 85,900.00	$ 84,119.81	2.1%
ANALYTICS	70	$ 112,087.37	$ 127,132.29	-11.8%
ASSET PROCUREMENT	10	$ 119,448.00	$ 112,046.70	6.6%
BENEFITS	13	$ 113,963.08	$ 113,751.77	0.2%
BUSINESS DEVELOPMENT	23	$ 174,340.17	$ 183,825.09	-5.2%
BUSINESS PROCESS & SERVICE QUALITY	60	$ 113,506.12	$ 110,197.92	3.0%
BUSINESS QUALITY MANAGEMENT	34	$ 139,986.35	$ 132,192.15	5.9%
BUSINESS STRATEGY & PLANNING	111	$ 142,848.43	$ 146,419.97	-2.4%
BUSINESS SYSTEMS ANALYSIS	28	$ 112,425.46	$ 115,650.07	-2.8%
CHEMICAL	2	$ 159,828.00	$ 147,405.00	8.4%
CIVIL	31	$ 120,803.23	$ 117,942.87	2.4%
COMMUNICATIONS	22	$ 116,962.91	$ 114,108.64	2.5%
COMPENSATION	9	$ 151,332.78	$ 146,988.78	3.0%
CONSTRUCTION PROJECT MANAGEMENT	97	$ 154,729.61	$ 150,794.22	2.6%
CORPORATE AFFAIRS	31	$ 136,849.42	$ 135,238.58	1.2%
CORPORATE GOVERNANCE	5	$ 144,230.40	$ 152,691.40	-5.5%
CO-WORKER CONNECTIONS	9	$ 158,218.67	$ 157,647.22	0.4%
CUSTOMER SERVICE	43	$ 98,384.09	$ 96,270.81	2.2%
CYBER SECURITY	60	$ 140,483.80	$ 142,277.70	-1.3%
DATA SCIENCE	36	$ 134,300.67	$ 138,491.61	-3.0%
DATABASE ADMINISTRATION	4	$ 133,986.00	$ 137,494.00	-2.6%
DESIGN SERVICES	1	$ 102,048.00	$ 93,161.00	9.5%
DIVERSITY EQUITY & INCLUSION	6	$ 129,000.00	$ 132,014.50	-2.3%
DOCUMENTATION & RECORD KEEPING	7	$ 92,334.86	$ 100,834.86	-8.4%
ELECTRICAL	198	$ 121,907.92	$ 127,931.19	-4.7%
EMPLOYEE RELATIONS	20	$ 136,746.00	$ 139,649.30	-2.1%
ENGINEERING & TECHNICAL LEADERSHIP	177	$ 160,669.56	$ 170,706.50	-5.9%
ENVIRONMENTAL & EMPLOYEE HEALTH & SAFETY	66	$ 129,996.42	$ 134,869.11	-3.6%
ETHICS & COMPLIANCE	39	$ 122,044.31	$ 120,516.03	1.3%
EXPLORATION & PRODUCTION OPERATIONS	92	$ 139,557.13	$ 135,417.59	3.1%
FACILITIES MANAGEMENT & PLANNING	11	$ 128,026.91	$ 123,308.45	3.8%
FINANCIAL CONTROL	14	$ 128,370.86	$ 125,048.14	2.7%
FINANCIAL FORECASTING	83	$ 133,686.27	$ 126,986.08	5.3%
HR TECHNOLOGY	6	$ 117,402.00	$ 118,153.83	-0.6%
INDUSTRIAL	11	$ 129,165.82	$ 129,749.64	-0.4%
INFORMATION & TECHNOLOGY LEADERSHIP	59	$ 181,749.76	$ 187,434.47	-3.0%
INFORMATION & TECHNOLOGY MANAGEMENT	42	$ 135,950.86	$ 134,786.26	0.9%
INTERNAL AUDIT	8	$ 151,854.00	$ 148,818.00	2.0%
INVESTOR RELATIONS	3	$ 144,136.00	$ 143,514.33	0.4%
LABOR RELATIONS	10	$ 118,992.00	$ 121,904.80	-2.4%
LABORATORY SERVICES	26	$ 116,136.92	$ 117,100.08	-0.8%
LEARNING & DEVELOPMENT	76	$ 109,511.68	$ 110,963.63	-1.3%
LEGAL PROFESSIONALS	27	$ 175,537.04	$ 192,811.52	-9.0%
MACHINE OPERATIONS	6	$ 159,164.00	$ 145,817.17	9.2%
MANUFACTURING PLANT MANAGEMENT	4	$ 163,359.25	$ 165,219.00	-1.1%
MARKETING GENERALISTS	39	$ 116,196.31	$ 113,782.21	2.1%
MECHANICAL	103	$ 125,972.85	$ 130,358.18	-3.4%
ORGANIZATIONAL DEVELOPMENT	11	$ 115,641.82	$ 119,591.45	-3.3%
PAYROLL	4	$ 105,756.00	$ 99,783.50	6.0%
PHYSICAL SECURITY	9	$ 126,021.33	$ 140,078.56	-10.0%
POWER GEN TRANSMISSION & DISTRIBUTION	320	$ 124,388.39	$ 127,190.68	-2.2%
PROCUREMENT	54	$ 105,523.48	$ 110,463.26	-4.5%
PROGRAM MANAGEMENT	39	$ 131,620.31	$ 135,340.49	-2.7%
PROJECT & PROGRAM MANAGEMENT	76	$ 131,642.05	$ 134,917.13	-2.4%
PROPERTY MANAGEMENT	3	$ 97,968.00	$ 116,946.00	-16.2%
RATES & REGULATION	17	$ 141,940.94	$ 148,034.41	-4.1%
REAL ESTATE MANAGEMENT	18	$ 125,030.67	$ 138,267.89	-9.6%
REGULATORY AFFAIRS	6	$ 142,528.00	$ 137,235.83	3.9%
RELATIONSHIP MANAGEMENT	37	$ 136,626.81	$ 127,225.43	7.4%
REPAIR & MAINTENANCE TRADES	19	$ 135,179.47	$ 132,335.11	2.1%
RISK MANAGEMENT	22	$ 134,107.64	$ 134,280.50	-0.1%
SALES & MARKETING	35	$ 152,831.20	$ 150,467.74	1.6%
SOFTWARE DEVELOPMENT	18	$ 123,482.67	$ 128,455.83	-3.9%
SOFTWARE PRODUCT ENGINEERING	193	$ 131,971.13	$ 141,143.11	-6.5%
SUPPLY CHAIN PLANNING & OPERATIONS	41	$ 119,682.15	$ 105,292.59	13.7%
SYSTEMS ADMINISTRATION & REPORTING	8	$ 128,673.00	$ 121,396.13	6.0%
SYSTEMS ARCHITECTURE	30	$ 147,988.40	$ 145,224.07	1.9%
SYSTEMS OPS & PRODUCTION CONTROL	7	$ 117,106.29	$ 105,890.00	10.6%
TALENT ACQUISITION	11	$ 114,759.27	$ 106,441.55	7.8%
TAX	14	$ 151,348.86	$ 137,469.86	10.1%
TECHNICAL ANALYST	206	$ 111,962.96	$ 120,420.50	-7.0%
TECHNOLOGY SUPPORT	16	$ 106,557.00	$ 112,983.69	-5.7%
TELECOM & INTERNET	4	$ 114,234.00	$ 122,458.50	-6.7%
TREASURY	4	$ 134,946.00	$ 125,379.75	7.6%
UTILITIES OPERATIONS	354	$ 135,218.66	$ 133,695.19	1.1%
WAREHOUSING & DISTRIBUTION	18	$ 108,813.33	$ 103,754.67	4.9%
WORKFORCE ANALYTICS	3	$ 158,040.00	$ 174,916.00	-9.6%

Non-Exempt:
2024 Market study

Job Family	# of Employees	Annual Salary	Market Data	Avg. Salary vs Market
ACCOUNTING	9	$ 72,508.78	$ 79,252.67	-8.5%
ACCOUNTS PAYABLE & RECEIVABLE	79	$ 64,337.84	$ 59,553.71	8.0%
ADMINISTRATIVE SUPPORT	43	$ 63,534.30	$ 56,417.07	12.6%
ASSET PROCUREMENT	3	$ 66,463.00	$ 65,221.00	1.9%
BENEFITS	2	$ 75,452.00	$ 73,156.00	3.1%
BUSINESS PROCESS & SERVICE QUALITY	15	$ 73,600.07	$ 70,174.13	4.9%
CREDIT & COLLECTIONS	5	$ 60,686.00	$ 65,770.20	-7.7%
CUSTOMER SERVICE	21	$ 64,369.00	$ 66,299.90	-2.9%
CYBER SECURITY	16	$ 55,946.63	$ 64,331.88	-13.0%
DESIGN SERVICES	1	$ 122,720.00	$ 100,191.00	22.5%
DOCUMENTATION & RECORD KEEPING	13	$ 64,747.15	$ 58,365.69	10.9%
EMPLOYEE RELATIONS	5	$ 68,369.80	$ 68,332.20	0.1%
ENGINEERING TECHNOLOGISTS & TECHNICIANS	287	$ 83,419.85	$ 89,010.38	-6.3%
ENVIRONMENTAL & EMPLOYEE HEALTH & SAFETY	4	$ 64,818.25	$ 54,675.75	18.6%
ETHICS & COMPLIANCE	30	$ 64,275.43	$ 69,058.43	-6.9%
FACILITIES MANAGEMENT & PLANNING	2	$ 73,174.50	$ 63,583.00	15.1%
HEAVY EQUIPMENT & CONSTRUCTION TRADES	4	$ 68,229.25	$ 61,920.00	10.2%
LABORATORY SERVICES	31	$ 75,824.13	$ 86,520.55	-12.4%
LEGAL PROFESSIONALS	4	$ 89,835.25	$ 96,839.75	-7.2%
MACHINE OPERATIONS	73	$ 77,143.51	$ 81,074.10	-4.8%
PAYROLL	16	$ 62,561.19	$ 60,594.25	3.2%
POWER GEN TRANSMISSION & DISTRIBUTION	124	$ 72,070.82	$ 73,390.63	-1.8%
PROCUREMENT	7	$ 70,312.71	$ 76,071.71	-7.6%
PROJECT & PROGRAM MANAGEMENT	145	$ 78,933.39	$ 77,160.83	2.3%
PROPERTY MANAGEMENT	6	$ 63,065.50	$ 68,762.83	-8.3%
REGULATORY AFFAIRS	17	$ 71,635.24	$ 75,127.82	-4.6%
REPAIR & MAINTENANCE TRADES	23	$ 85,917.48	$ 82,548.39	4.1%
UTILITIES OPERATIONS	32	$ 75,026.84	$ 67,728.16	10.8%
WAREHOUSING & DISTRIBUTION	2	$ 61,641.00	$ 64,109.00	-3.8%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Annual Employee Incentive Compensation
($000)

Case No.: U-21870
Exhibit No.: A-73 (AMC-3)
Page: 1 of 2
Witness: AMConrad
Date: June 2025

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2024	(c) Projected 12-Mos Ending 4/30/2027
1	Officer	429	467
	Labor	429	467
	Material	0	0
	Contractor	0	0
	Other	0	0
	Business Expenses	0	0
2	Non-Officer	1675	1744
	Labor	1675	1744
	Material	0	0
	Contractor	0	0
	Other	0	0
	Business Expenses	0	0
3	Total "Annual Incentive" O&M Expenses	2104	2211
	Labor	2104	2211
	Material	0	0
	Contractor	0	0
	Other	0	0
	Business Expenses	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Annual Incentive
($000)

Case No.: U-21870
Exhibit No.: A-73 (AMC-3)
Page: 2 of 2
Witness: AMConrad
Date: June 2025

Line No.	Description	(a)	(b) Actual 12 Mos Ended Dec 31, 2024	(c) Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2024	(d) Merit & Inflation 12 Mos Ending Dec 31, 2025	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(f) Merit & Inflation 12 Mos Ending Dec 31, 2026	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	(h) Merit & Inflation 4 Mos Ending Apr 30, 2027	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Apr 30, 2027
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	Officer		429	429	9	452	11	463	4	14	467
	Labor		429	429	9	452	11	463	4	14	467
	Material				0		0		0		0
	Contractor				0		0		0		0
	Other				0		0		0		0
	Business Expenses				0		0		0		0
2	Non-Officer		1,675	1,675	35	1,689	41	1,730	14	(21)	1,744
	Labor		1,675	1,675	35	1,689	41	1,730	14	(21)	1,744
	Material				0		0		0		0
	Contractor				0		0		0		0
	Other				0		0		0		0
	Business Expenses				0		0		0		0
3	Total "Annual Incentive" O&M Expenses		2,104	2,104	44	2,141	51	2,193	18	(7)	2,211
	Labor		2,104	2,104	44	2,141	51	2,193	18	(7)	2,211
	Material		0	0	0	0	0	0	0	0	0
	Contractor		0	0	0	0	0	0	0	0	0
	Other		0	0	0	0	0	0	0	0	0
	Business Expenses		0	0	0	0	0	0	0	0	0

Notes

	12-Mo Ending 2025	12-Mo Ending 2026	4-Mo Ending 2027
Annual inflation rates per Company witness Rayl	2.1%	2.4%	2.4%
Number of months in the period	12	12	4
Pro-rated inflation rate	2.1%	2.4%	0.8%

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. and CEO	$1,075,000	$1,343,750	125%	$2,418,750	$4,437,940	$6,856,690
Ameren Corporation	Martin J. Lyons Jr.	Chairman, Pres. and CEO	$1,275,000	$1,593,750	125%	$2,868,750	$5,209,678	$8,078,428
Atmos Energy Corporation	John K. Akers	Pres. and CEO	$1,100,000	$1,210,000	110%	$2,310,000	$4,560,079	$6,870,079
CenterPoint Energy, Inc.	Jason P. Wells	Pres. and CEO	$1,150,000	$1,437,500	125%	$2,587,500	$5,749,994	$8,337,494
Consolidated Edison, Inc.	Timothy P. Cawley	Pres. and CEO	$1,400,000	$1,750,000	125%	$3,150,000	$7,993,638	$11,143,638
DTE Energy Company	Gerardo Norcia	Chairman and CEO	$1,340,000	$1,809,000	135%	$3,149,000	$7,687,858	$10,836,858
Edison International	Pedro J. Pizarro	Pres. and CEO	$1,400,000	$1,890,000	135%	$3,290,000	$9,310,106	$12,600,106
Entergy Corporation	Andrew S. Marsh	Chairman and CEO	$1,250,000	$1,625,000	130%	$2,875,000	$7,190,821	$10,065,821
Evergy, Inc.	David A. Campbell	Chairman, Pres., and CEO	$1,056,000	$1,320,000	125%	$2,376,000	$4,961,250	$7,337,250
Eversource Energy	Joseph R. Nolan Jr.	Chairman, Pres. and CEO	$1,384,770	$1,960,000	142%	$3,344,770	$7,510,128	$10,854,898
Hawaiian Electric Industries, Inc.	Scott W. H. Seu	Pres. and CEO	$995,750	$995,750	100%	$1,991,500	$1,695,190	$3,686,690
NiSource Inc	Lloyd Yates	Pres. and CEO	$1,150,000	$1,495,000	130%	$2,645,000	$8,266,043	$10,911,043
OGE Energy Corp.	Sean Trauschke	Chairman, CEO and Pres.	$1,204,622	$1,325,084	110%	$2,529,706	$5,099,875	$7,629,581
Pinnacle West Capital Corporation	Theodore N. Geisler	Chair of the Board, Pres. and CEO	$1,000,000	$1,200,000	120%	$2,200,000	$3,000,000	$5,200,000
PPL Corporation	Vincent Sorgi	Pres. and CEO	$1,238,060	$1,547,575	125%	$2,785,635	$6,741,435	$9,527,070
Public Service Enterprise Group Incorporated	Ralph A. LaRossa	Chair of the Board, Pres. and CEO	$1,345,600	$1,816,560	135%	$3,162,160	$8,500,035	$11,662,195
Sempra Energy	Jeffrey W. Martin	Chairman, CEO and Pres.	$1,600,000	$2,800,000	175%	$4,400,000	$13,503,977	$17,903,977
WEC Energy Group Inc	Scott J. Lauber	Pres. and CEO	$1,130,118	$1,582,165	140%	$2,712,283	$5,518,335	$8,230,618
Xcel Energy Inc.	Bob Frenzel	Chairman, Pres. and CEO	$1,400,000	$1,960,000	140%	$3,360,000	$12,078,539	$15,438,539
n=19								
		Summary Statistics [3]						
		25th Percentile	$1,115,059	$1,334,417	125%	$2,474,228	$5,030,563	$7,483,416
		50th Percentile	$1,238,060	$1,582,165	125%	$2,785,635	$6,741,435	$9,527,070
		Average	$1,236,575	$1,613,744	129%	$2,850,319	$6,790,259	$9,640,578
		75th Percentile	$1,365,185	$1,812,780	135%	$3,156,080	$8,129,841	$11,027,341
CMS Energy Corporation	**Garrick J. Rochow**	**Director, Pres. and CEO**	**$1,250,000**	**$1,562,500**	**125%**	**$2,812,500**	**$6,651,245**	**$9,463,745**

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	Robert J. Durian	EVP and CFO	$650,000	$520,000	80%	$1,170,000	$1,469,465	$2,639,465
Ameren Corporation	Michael L. Moehn	Senior EVP and CFO	$860,000	$731,000	85%	$1,591,000	$3,366,103	$4,957,103
Atmos Energy Corporation	Christopher T. Forsythe	SVP and CFO	$575,000	$402,500	70%	$977,500	$1,003,828	$1,981,328
CenterPoint Energy, Inc.	Christopher A. Foster	EVP and CFO	$725,000	$580,000	80%	$1,305,000	$3,834,987	$5,139,987
Consolidated Edison, Inc.	Kirkland Andrews	SVP and CFO	$810,000	$648,000	80%	$1,458,000	$3,201,000	$4,659,000
DTE Energy Company	David Ruud	EVP and CFO	$710,192	$616,250	87%	$1,326,442	$2,129,484	$3,455,926
Edison International	Maria Rigatti	EVP and CFO	$800,000	$680,000	85%	$1,480,000	$2,200,142	$3,680,142
Entergy Corporation	Kimberly A. Fontan	EVP and CFO	$706,250	$600,313	85%	$1,306,563	$1,861,141	$3,167,704
Evergy, Inc.	W. Bryan Buckler	EVP and CFO	$660,000	$528,000	80%	$1,188,000	$3,086,663	$4,274,663
Eversource Energy	John M. Moreira	EVP, CFO and Treasurer	$826,925	$680,000	82%	$1,506,925	$2,083,794	$3,590,719
Hawaiian Electric Industries, Inc.	Ann C. Teranishi	ASB Pres. and CEO	$800,000	$600,000	75%	$1,400,000	$520,000	$1,920,000
NiSource Inc	Shawn Anderson	EVP and CFO	$650,000	$487,500	75%	$1,137,500	$2,211,442	$3,348,942
OGE Energy Corp.	Charles B. Walworth	CFO and Treasurer	$560,019	$392,013	70%	$952,032	$840,029	$1,792,061
Pinnacle West Capital Corporation	Andrew D. Cooper	SVP and CFO	$630,000	$441,000	70%	$1,071,000	$1,602,875	$2,673,875
PPL Corporation	Dean A. Del Vecchio	EVP and Chief Technology and Innovation Officer	$650,000	$552,500	85%	$1,202,500	$2,360,112	$3,562,612
Public Service Enterprise Group Incorporated	Daniel J. Cregg	EVP and CFO	$825,000	$742,500	90%	$1,567,500	$3,597,723	$5,165,223
Sempra Energy	Trevor I. Mihalik	EVP and Group Pres., California	$950,000	$950,000	100%	$1,900,000	$4,032,724	$5,932,724
WEC Energy Group Inc	Xia Liu	EVP and CFO	$841,853	$715,575	85%	$1,557,428	$2,107,082	$3,664,510
Xcel Energy Inc.	Brian Van Abel	EVP and CFO	$800,000	$680,000	85%	$1,480,000	$2,516,691	$3,996,691
n=19								
		Summary Statistics[3]						
		25th Percentile	$650,000	$524,000	78%	$1,179,000	$1,732,008	$2,920,789
		50th Percentile	$725,000	$600,313	82%	$1,326,442	$2,200,142	$3,590,719
		Average	$738,434	$607,745	82%	$1,346,178	$2,317,120	$3,663,299
		75th Percentile	$817,500	$680,000	85%	$1,493,463	$3,143,832	$4,466,832
CMS Energy Corporation	**Rejji P. Hayes**	**EVP and CFO**	**$810,000**	**$648,000**	**80%**	**$1,458,000**	**$2,082,626**	**$3,540,626**

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	Raja Sundararajan	EVP, Strategy and Customer Solutions	$600,000	$450,000	75%	$1,050,000	$1,002,623	$2,052,623
Ameren Corporation	Mark C. Birk	Chairman and Pres., Ameren Missouri	$650,000	$520,000	80%	$1,170,000	$1,174,177	$2,344,177
Atmos Energy Corporation	Karen E. Hartsfield	SVP, GC, and Corporate Secretary	$510,000	$306,000	60%	$816,000	$718,561	$1,534,561
CenterPoint Energy, Inc.	Monica Karuturi	EVP and GC	$725,000	$580,000	80%	$1,305,000	$1,884,988	$3,189,988
Consolidated Edison, Inc.	Matthew Ketschke	Pres., Con Edison of New York	$824,000	$659,200	80%	$1,483,200	$2,470,440	$3,953,640
DTE Energy Company	Joi Harris	Pres. and COO	$626,154	$578,000	92%	$1,204,154	$1,718,346	$2,922,500
Edison International	Steven D. Powell	Pres. and CEO, SCE	$770,000	$654,500	85%	$1,424,500	$2,002,101	$3,426,601
Entergy Corporation	Roderick K. West	Former Group Pres., Utility Operations	$835,753	$668,602	80%	$1,504,355	$1,603,709	$3,108,064
Evergy, Inc.	Kevin E. Bryant	Former EVP and COO and Former EVP, Corporate Initiatives	$645,000	$516,000	80%	$1,161,000	$1,357,053	$2,518,053
Eversource Energy	Paul W. Chodak III	EVP and COO	$850,002	$680,000	80%	$1,530,002	$1,886,789	$3,416,791
Hawaiian Electric Industries, Inc.	Shelee M. T. Kimura	Hawaiian Electric Pres. and CEO	$650,000	$487,500	75%	$1,137,500	$704,346	$1,841,846
NiSource Inc	Michael Luhrs	EVP, Risk and Strategy and Chief Commercial Officer	$600,000	$450,000	75%	$1,050,000	$2,084,541	$3,134,541
OGE Energy Corp.	W. Bryan Buckler	Former CFO and VP	$509,304	$356,513	70%	$865,817	$862,455	$1,728,272
Pinnacle West Capital Corporation	Adam C. Heflin	EVP and Chief Nuclear Officer of PVGS, APS	$735,000	$551,250	75%	$1,286,250	$1,337,015	$2,623,265
PPL Corporation	Joseph P. Bergstein Jr.	EVP and CFO	$691,150	$587,478	85%	$1,278,628	$1,792,118	$3,070,746
Public Service Enterprise Group Incorporated	Kim C. Hanemann	Pres. and COO, PSE&G	$775,000	$658,750	85%	$1,433,750	$1,800,019	$3,233,769
Sempra Energy	Justin C. Bird	EVP, CEO, Sempra Infrastructure	$780,000	$702,000	90%	$1,482,000	$2,035,528	$3,517,528
WEC Energy Group Inc	Michael W. Hooper	Pres. WI Utilities	$650,000	$520,000	80%	$1,170,000	$1,116,330	$2,286,330
Xcel Energy Inc.	Amanda Rome	EVP, Group Pres., Utilities and Chief Customer Officer	$700,000	$560,000	80%	$1,260,000	$2,016,739	$3,276,739
n=19								
		Summary Statistics[3]						
		25th Percentile	$635,577	$501,750	75%	$1,149,250	$1,145,254	$2,315,254
		50th Percentile	$691,150	$560,000	80%	$1,260,000	$1,718,346	$3,070,746
		Average	$690,861	$551,884	79%	$1,242,745	$1,556,204	$2,798,949
		75th Percentile	$772,500	$656,625	83%	$1,429,125	$1,944,445	$3,255,254
CMS Energy Corporation	**Shaun M. Johnson**	**GC and SVP, Business Optimization**	**$620,000**	**$465,000**	**75%**	**$1,085,000**	**$1,249,550**	**$2,334,550**

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	David A. de Leon	SVP and Pres. of WPL	$465,000	$325,500	70%	$790,500	$545,784	$1,336,284
Ameren Corporation	Leonard P. Singh	Chairman and Pres., Ameren Illinois	$625,000	$500,000	80%	$1,125,000	$1,129,033	$2,254,033
Atmos Energy Corporation	John S. McDill	SVP, Utility Operations	$500,000	$300,000	60%	$800,000	$718,561	$1,518,561
CenterPoint Energy, Inc.	Jason M. Ryan	EVP, Regulatory Services and Government Affairs	$525,000	$367,500	70%	$892,500	$1,050,003	$1,942,503
Consolidated Edison, Inc.	Deneen L. Donnley	SVP and GC	$695,700	$486,990	70%	$1,182,690	$1,394,034	$2,576,724
DTE Energy Company	Trevor F. Lauer	Vice Chairman and Group Pres.	$669,231	$544,000	81%	$1,213,231	$1,507,506	$2,720,737
Edison International	Adam S. Umanoff	EVP, GC and Corporate Secretary	$710,000	$603,500	85%	$1,313,500	$1,562,058	$2,875,558
Entergy Corporation	Marcus V. Brown	EVP and GC	$791,754	$633,403	80%	$1,425,157	$1,493,209	$2,918,366
Evergy, Inc.	Charles A. Caisley	EVP, Public Affairs and Chief Customer Officer	$575,000	$402,500	70%	$977,500	$1,144,511	$2,122,011
Eversource Energy	Susan Sgroi	EVP, Human Resources and Information Technology	$533,654	$389,000	73%	$922,654	$1,559,857	$2,482,511
Hawaiian Electric Industries, Inc.	Scott T. DeGhetto	EVP, CFO and Treasurer	$620,000	$620,000	100%	$1,240,000	$296,863	$1,536,863
NiSource Inc	Melody Birmingham	EVP and Group Pres., Utilities	$670,000	$502,500	75%	$1,172,500	$1,583,297	$2,755,797
OGE Energy Corp.	William H. Sultemeier	GC, Corporate Secretary and Chief Compliance Officer	$517,394	$336,306	65%	$853,700	$766,669	$1,620,369
Pinnacle West Capital Corporation	Jacob Tetlow	EVP and CFO of APS	$560,000	$420,000	75%	$980,000	$1,587,016	$2,567,016
PPL Corporation	Francis X. Sullivan	EVP and COO	$682,000	$579,700	85%	$1,261,700	$1,768,409	$3,030,109
Public Service Enterprise Group Incorporated	Tamara L. Linde	Former EVP, GC and CLO	$737,400	$626,790	85%	$1,364,190	$1,800,019	$3,164,209
Sempra Energy	Karen L. Sedgwick	EVP and CFO	$630,000	$567,000	90%	$1,197,000	$2,125,712	$3,322,712
WEC Energy Group Inc	Margaret C. Kelsey	EVP, GC and Corporate Secretary	$640,665	$480,499	75%	$1,121,164	$1,090,360	$2,211,524
Xcel Energy Inc.	Timothy O'Connor	EVP and COO	$800,000	$680,000	85%	$1,480,000	$1,766,730	$3,246,730
n=19								
		Summary Statistics [3]						
		25th Percentile	$546,827	$395,750	70%	$950,077	$1,070,182	$2,032,257
		50th Percentile	$630,000	$500,000	75%	$1,172,500	$1,493,209	$2,567,016
		Average	$628,831	$492,905	78%	$1,121,736	$1,309,981	$2,431,717
		75th Percentile	$688,850	$591,600	85%	$1,250,850	$1,585,157	$2,896,962
CMS Energy Corporation	**LeeRoy Wells Jr.**	**SVP, Operations**	**$575,000**	**$431,250**	**75%**	**$1,006,250**	**$1,067,357**	**$2,073,607**

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	**Executive**	**Position**	**Base Salary**	**Target Annual Incentive ($)**	**Target Annual Incentive (%)**	**Target Total Cash Compensation [1]**	**Total Long-Term Incentive**	**Target Total Direct Compensation [2]**
Ameren Corporation	Chonda J. Nwamu	Former EVP, GC and Secretary	$658,000	$460,600	70%	$1,118,600	$1,018,855	$2,137,455
Atmos Energy Corporation	John M. Robbins	SVP and Human Resources	$383,000	$229,800	60%	$612,800	$718,561	$1,331,361
CenterPoint Energy, Inc.	Lynne Harkel Rumford	Former EVP and CHRO	$475,000	$332,500	70%	$807,500	$949,976	$1,757,476
Consolidated Edison, Inc.	Robert Sanchez	Pres., Shared Services, Con Edison of New York	$585,300	$468,240	80%	$1,053,540	$1,173,459	$2,226,999
DTE Energy Company	Mark W. Stiers	Pres. and CFO, DTE Vantage and Energy Trading	$624,769	$476,250	76%	$1,101,019	$1,317,750	$2,418,769
Edison International	Caroline Choi	EVP, Public Policy and Corporate Affairs	$542,880	$352,872	65%	$895,752	$841,635	$1,737,387
Entergy Corporation	Peter S. Norgeot Jr.	EVP and COO	$669,760	$502,320	75%	$1,172,080	$1,529,283	$2,701,363
Evergy, Inc.	Heather A. Humphrey	SVP, GC and Corporate Secretary	$547,500	$355,875	65%	$903,375	$817,075	$1,720,450
Eversource Energy	Gregory B. Butler	EVP and GC	$727,156	$512,000	70%	$1,239,156	$1,219,021	$2,458,177
Hawaiian Electric Industries, Inc.	Kurt K. Murao	EVP, GC, Chief Administrative Officer and Corporate Secretary	$499,800	$299,880	60%	$799,680	$478,622	$1,278,302
NiSource Inc	William Jefferson	EVP, Operations and Chief Safety Officer	$625,000	$468,750	75%	$1,093,750	$1,476,957	$2,570,707
OGE Energy Corp.	D.O. Jones	VP, Utility Operations	$454,553	$318,187	70%	$772,740	$721,679	$1,494,419
PPL Corporation	Wendy E. Stark	EVP, Utilities and CLO	$620,000	$527,000	85%	$1,147,000	$1,213,156	$2,360,156
Public Service Enterprise Group Incorporated	Charles V. McFeaters	Pres. and Chief Nuclear Officer	$676,000	$507,000	75%	$1,183,000	$1,200,076	$2,383,076
Sempra Energy	Diana L. Day	CLO	$510,000	$306,000	60%	$816,000	$866,171	$1,682,171
WEC Energy Group Inc	Robert M. Garvin	EVP, External Affairs	$577,692	$433,269	75%	$1,010,961	$979,768	$1,990,729
Xcel Energy Inc.	Rob Berntsen	EVP, Chief Legal and Compliance Officer	$600,000	$450,000	75%	$1,050,000	$1,716,772	$2,766,772
n=17								
		Summary Statistics[3][4]						
		25th Percentile	$510,000	$332,500	65%	$816,000	$841,635	$1,720,450
		50th Percentile	$585,300	$450,000	70%	$1,050,000	$1,018,855	$2,137,455
		Average	$575,083	$411,797	71%	$986,880	$1,072,872	$2,059,751
		75th Percentile	$625,000	$476,250	75%	$1,118,600	$1,219,021	$2,418,769
CMS Energy Corporation	**Brandon J. Hofmeister**	**SVP, Sustainability and External Affairs**	**$545,000**	**$354,250**	**65%**	**$899,250**	**$905,858**	**$1,805,108**

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.
4. Analysis does not include fifth highest-paid officers for Alliant or Pinnacle West Capital because the Executive Chairman was excluded from the analysis for Alliant and the former CFO was excluded for Pinnacle West Capital.

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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-75 (PDD-51)
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	Description	Source	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	PowerMiDrive electric vehicle expenditures	Ex. A-164 (JAM-2)	917	2,896	2,947	3,876	5,116	7,734			
2	2019 amortization expense	Line 1, col. (c) / 5 years	-	183	183	183	183	183			
3	2020 amortization expense	Line 1, col. (d) / 5 years	-	-	579	579	579	579	579		
4	2021 amortization expense	Line 1, col. (e) / 5 years	-	-	-	589	589	589	589	589	
5	2022 amortization expense	Line 1, col. (f) / 5 years	-	-	-	-	775	775	775	775	775
6	2023 amortization expense	Line 1, col. (g) / 5 years	-	-	-	-	-	1,023	1,023	1,023	1,023
7	2024 amortization expense	Line 1, col. (h) / 5 years	-	-	-	-	-	-	1,547	1,547	1,547
8	Total PowerMiDrive amortization expense	Sum of Lines 2 through 7	-	183	763	1,352	2,127	3,151	4,514	3,935	3,345
9	PowerMiFleet electric vehicle expenditures	Ex. A-164 (JAM-2)	-	-	1,009	1,785	2,906	3,548			
10	2021 amortization expense	Line 9, col. (e) / 5 years	-	-	-	202	202	202	202	202	
11	2022 amortization expense	Line 9, col. (f) / 5 years	-	-	-	-	357	357	357	357	357
12	2023 amortization expense	Line 9, col. (g) / 5 years	-	-	-	-	-	581	581	581	581
13	2024 amortization expense	Line 9, col. (h) / 5 years	-	-	-	-	-	-	710	710	710
14	Total PowerMiFleet amortization expense	Sum of Lines 10 through 13	-	-	-	202	559	1,140	1,849	1,849	1,648

Line No.			12 Months Ending 4/30/2026	12 Months Ending 4/30/2027	Average Balance 4/30/2027
15	Test year PowerMiDrive amortization expense	(Line 8, col. (j)) ÷ 12 * 8) + (Line 8, col. (k)) ÷ 12 * 4)		3,738	
16	Test year PowerMiFleet amortization expense	(Line 14, col. (j)) ÷ 12 * 8) + (Line 14, col. (k)) ÷ 12 * 4)		1,782	
17	Total test year amortization expense	Line 15 + Line 16		5,520	
18	PowerMiDrive deferred balance	See Notes {1}, {2}, and {3} below, respectively	10,085	6,347	8,216
19	PowerMiFleet deferred balance	See Notes {4}, {5}, and {6} below, respectively	4,881	3,099	3,990

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 9, col. (c) through (j) - ((line 9, col. (k) ÷ 12 * 4)
{3} (Line 18, col. (c) + line 18, col. (d)) ÷ 2
{4} (Sum of line 9, col. (e) through (i) - sum of line 14, col. (e) through (i)) - ((line 14, col. (j) ÷ 12 * 4)
{5} Sum of line 9, col. (e) through (j) - sum of line 14, col. (e) through (j) - ((line 14, col. (k) ÷ 12 * 4)
{6} (Line 19, col. (c) + line 19, 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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-76 (PDD-52)
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Actual 2021	(d) Actual 2022	(e) Actual 2023	(f) Actual 2024	(g) Forecast 2025	(h) Forecast 2026	(i) Forecast 2027
1	Karn deferred retention/separation costs	SAP Accounts 1670070 & 1757310	7,016	4,828	1,501	0			
2	2021 amortization expense	Line 1, col. (c) / 3 years	-	2,339	2,339	2,339	-	-	-
3	2022 amortization expense	Line 1, col. (d) / 3 years	-	-	1,609	1,609	1,609	-	-
4	2023 amortization expense	Line 1, col. (e) / 3 years	-	-	-	500	500	500	-
5	2024 amortization expense	Line 1, col. (f) / 3 years	-	-	-	-	0	0	0
6	Total amortization expense	Sum of Lines 2 through 5	-	2,339	3,948	4,448	2,110	500	0
7	Campbell deferred retention/separation costs	SAP Accounts 1670080 & 1757320	-	23,904	15,847	8,626	6,249		
8	2022 amortization expense	Line 7, col. (d) / 3 years	-	-	7,968	7,968	7,968	-	-
9	2023 amortization expense	Line 7, col. (e) / 3 years	-	-	-	5,282	5,282	5,282	-
10	2024 amortization expense	Line 7, col. (f) / 3 years	-	-	-	-	2,875	2,875	2,875
11	2025 amortization expense	Line 7, col. (g) / 3 years	-	-	-	-	-	2,083	2,083
12	Total amortization expense	Sum of Lines 8 through 11	-	-	7,968	13,250	16,126	10,241	4,958

Line No.	Description	Source	12 Months Ending 4/30/2026	12 Months Ending 4/30/2027	Average Balance 4/30/2027
13	Test year Karn amortization expense	(Line 6, col. (h)) ÷ 12 * 8) + (Line 6, col. (i)) ÷ 12 * 4)		334	
14	Test year Campbell amortization expense	(Line 12, col. (h)) ÷ 12 * 8) + (Line 12, col. (i)) ÷ 12 * 4)		8,480	
15	Total test year amortization expense	Line 13 + Line 14		8,813	
16	Karn deferred balance	See Notes {1}, {2}, and {3} below, respectively	334	0	167
17	Campbell deferred balance	See Notes {4}, {5}, and {6} below, respectively	13,868	5,388	9,628

Notes

{1} (Sum of line 1, col. (c) through (g) - sum of line 6, col. (c) through (g)) - ((line 6, col. (h) ÷ 12 * 4)
{2} Sum of line 1, col. (c) through (h) - sum of line 7, col. (c) through (h) - ((line 7, col. (i) ÷ 12 * 4)
{3} (Line 16, col. (c) + line 16, col. (d)) ÷ 2
{4} (Sum of line 7, col. (c) through (g) - sum of line 12, col. (c) through (g)) - ((line 12, col. (h) ÷ 12 * 4)
{5} Sum of line 7, col. (c) through (h) - sum of line 12, col. (c) through (h) - ((line 12, col. (i) ÷ 12 * 4)
{6} (Line 17, col. (c) + line 17, col. (d)) ÷ 2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-77 (PDD-53)
Page: 1 of 1
Witness: PDDalv
Date: June 2025

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Line No.	Description	Source	Actual 12/31/2024	4 Months Ending 04/30/2025	12 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)		440,495	417,612	348,963	280,315	211,666	143,018	74,369	5,721									
2	Amortization Expense	(a)		(22,883)	(68,649)	(68,649)	(68,649)	(68,649)	(68,649)	(68,649)	(5,721)									
3	Ending Balance	Sum of Line 1 + Line 2	440,495	417,612	348,963	280,315	211,666	143,018	74,369	5,721	0									
4	13-Month Average Balance					314,639														

			Actual 12/31/2024	4 Months Ending 04/30/2025	12 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 Asset																				
5	Beginning Balance	SAP Accounts (1032004, 1138100, and 11183200)		877,365	858,395	801,485	744,575	687,665	630,755	573,844	516,934	460,024	403,114	346,204	289,293	232,383	175,473	118,563	61,653	4,742
6	Amortization Expense	(b)		(18,970)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(56,910)	(4,743)
7	Ending Balance	Sum of Line 5 + Line 6	877,365	858,395	801,485	744,575	687,665	630,755	573,844	516,934	460,024	403,114	346,204	289,293	232,383	175,473	118,563	61,653	4,742	(0)
8	13-Month Average Balance					773,030														

Notes

(a) Amortization Expense for Campbell Units 1&2 is based on the total amount of $440,494,582 as of December 31, 2024 to be amortized on straight-line basis through May 2031 (or 77 months) resulting in monthly amortization expense of $5,720,709.

(b) Amortization Expense for Campbell Units 3 is based on the total amount of $877,365,405 as of December 31, 2024 to be amortized on straight-line basis through May 2040 (or 185 months) resulting in monthly amortization expense of $4,742,516.

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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-78 (PDD-54)
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	Description	Source	2022	2023	2024	2025	2026	2027
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Karn 1-2 deferred decommissioning costs	SAP Account 1670304 and 1757302	11,533	24,895	21,269			
2	2022 amortization expense	Line 1, col. (c) / 8 years /12 *10 (amortization started in March 2024 when approved in U-21389)	-	-	1,201	1,442	1,442	1,442
3	2023 amortization expense	Line 1, col. (d) / 7 years	-	-	-	3,556	3,556	3,556
4	2024 amortization expense	Line 1, col. (e) / 6 years					3,545	3,545
5	Total amortization expense	Sum of Lines 2 through 5	-	-	1,201	4,998	8,543	8,543
6	Campbell deferred decommissioning costs	SAP Account 1670302, 1670303, 1757306 and 1757307	1,382	15,353	5,244			
7	2022 amortization expense	Line 6, col. (c) / 10 years/12 * 10 (amortization started in March 2024 when approved in U-21389)	-	-	115	138	138	138
8	2023 amortization expense	Line 6, col. (d) / 10 years	-	-	-	1,535	1,535	1,535
9	2024 amortization expense	Line 6, col. (e) / 10 years					524	524
10	Total amortization expense	Sum of Lines 7 through 8	-	-	115	1,673	2,198	2,198

Line No.			12 Months Ending 4/30/2026	12 Months Ending 4/30/2027	Average Balance 4/30/2027
11	Test year Karn amortization expense	(Line 5, col. (g)) ÷ 12 * 8) + (Line 5, col. (h)) ÷ 12 * 4)		8,543	
12	Test year Campbell amortization expense	(Line 10, col. (g)) ÷ 12 * 8) + (Line 10, col. (h)) ÷ 12 * 4)		2,198	
13	Total test year amortization expense	Line 11 + Line 12		10,741	
14	Karn 1-2 deferred balance	See Notes {1}, {2}, and {3} below, respectively	48,650	40,107	44,379
15	Campbell deferred balance	See Notes {4}, {5}, and {6} below, respectively	19,457	17,259	18,358

Notes

{1} (Sum of line 1, col. (c) through (g) - sum of line 5, col. (c) through (f)) - ((line 5, col. (g) ÷ 12 * 4)
{2} Sum of line 1, col. (c) through (g) - sum of line 6, col. (c) through (g) - ((line 6, col. (h) ÷ 12 * 4)
{3} (Line 14, col. (c) + line 14, col. (d)) ÷ 2
{4} (Sum of line 6, col. (c) through (g) - sum of line 10, col. (c) through (g)) - ((line 10, col. (g) ÷ 12 * 4)
{5} Sum of line 6, col. (c) through (g) - sum of line 10, col. (c) through (g) - ((line 10, col. (h) ÷ 12 * 4)
{6} (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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-79 (PDD-55)
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) 2022	(d) 2023	(e) 2024	(f) 2025	(g) 2026	(h) 2027
1	Karn 1-2, Classic 7, and Campbell Ash Disposal Costs Deferred	SAP Accounts 1670300, 1670301, 1757303 and 1757308	11,075	18,273	52,147			
2	2022 amortization expense	Line 1, col. (c) / 10 years/12 *10 (amortization started in March 2024 when approved in U-21389)	-	-	923	1,108	1,108	1,108
3	2023 amortization expense	Line 1, col. (d) / 10 years	-	-	-	1,827	1,827	1,827
4	2024 amortization expense	Line 1, col. (d) / 10 years					5,215	5,215
5	Total amortization expense	Sum of Lines 2 through 5	-	-	923	2,935	8,150	8,150

Line No.	Description	Source	12 Months Ending 4/30/2026	12 Months Ending 4/30/2027	Average Balance 4/30/2027
6	Test year amortization expense	(Line 5, col. (g)) ÷ 12 * 8) + (Line 5, col. (h)) ÷ 12 * 4)		8,150	
7	Ash Disposal Costs Deferred Balance	See Notes {1}, {2}, and {3} below, respectively	74,921	66,771	70,846

Notes

{1} (Sum of line 1, col. (c) through (e) - sum of line 5, col. (c) through (f)) - ((line 5, col. (g) ÷ 12 * 4)
{2} (Sum of line 1, col. (c) through (e) - sum of line 5, col. (c) through (g)) - ((line 5, col. (h) ÷ 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, 2027
($000)

Case No.: U-21870
Exhibit No.: A-80 (PDD-56)
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2027
1	Pension volatility mechanism asset / (liability)	WP-KKG-3, 4, and 5	(11,466)	(10,729)	3,073			
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	-	-	-	307	307	307
5	Total amortization expense	Sum of Lines 2 through 4	-	(1,147)	(2,220)	(1,912)	(1,912)	(1,912)
6	OPEB volatility mechanism asset / (liability)	WP-KKG-3, 4, and 5	23,302	(3,579)	(1,596)			
7	2023 amortization expense	Line 6, col. (d) / 10 years	-	2,330	2,330	2,330	2,330	2,330
8	2024 amortization expense	Line 6, col. (e) / 10 years	-	-	(358)	(358)	(358)	(358)
9	2025 amortization expense	Line 6, col. (f) / 10 years	-	-	-	(160)	(160)	(160)
10	Total amortization expense	Sum of Lines 7 through 8	-	2,330	1,972	1,813	1,813	1,813

Line No.	Description	Source	12 Months Ending 4/30/2026	12 Months Ending 4/30/2027	Average Balance 4/30/2027
11	Test year pension amortization expense	(Line 5, col. (f)) ÷ 12 * 8) + (Line 5, col. (g)) ÷ 12 * 4)		(1,912)	
12	Test year OPEB amortization expense	(Line 10, col. (f)) ÷ 12 * 8) + (Line 10, col. (g)) ÷ 12 * 4)		1,813	
13	Total test year amortization expense	Line 11 + Line 12		(100)	
14	Pension volatility mechanism deferred balance	See Notes {1}, {2}, and {3} below, respectively	(15,119)	(13,207)	(14,163)
15	OPEB volatility mechanism deferred balance	See Notes {4}, {5}, and {6} below, respectively	13,220	11,407	12,314

Notes

{1} (Sum of line 1, col. (c) through (e) - sum of line 5, col. (c) through (e)) - ((line 5, col. (f) ÷ 12 * 4)
{2} Sum of line 1, col. (c) through (f) - sum of line 6, col. (c) through (f) - ((line 6, col. (g) ÷ 12 * 4)
{3} (Line 14, col. (c) + line 14, col. (d)) ÷ 2
{4} (Sum of line 6, col. (c) through (e) - sum of line 10, col. (c) through (e)) - ((line 10, col. (f) ÷ 12 * 4)
{5} Sum of line 6, col. (c) through (f) - sum of line 10, col. (c) through (f) - ((line 10, col. (g) ÷ 12 * 4)
{6} (Line 15, col. (c) + line 15, col. (d)) ÷ 2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Campbell Regulatory Asset - Return On
For the Projected 12-Month Period Ending April 30, 2027
(000)

Case No.: U-21870
Exhibit No.: A-81 (PDD-57)
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	(a) Description	(b) Source	(c) Amount
	Return on Campbell Regulatory Asset		
1	Campbell 1-2 Regulatory Asset - Average Balance	Ex. A-77 (PDD-53), Line 4	314,639
2	Campbell 3 Regulatory Asset - Average Balance	Ex. A-77 (PDD-53), Line 8	773,030
3	Total Campbell Average Regulatory Asset Balance Test Year	Line 1 + Line 2	1,087,669
	Cost of Capital		
4	Pre-tax Weighted Average Cost of Capital[1]	Note 1	7.12%
5	Return on Campbell Regulatory Asset	Line 3 * Line 4	77,486

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-PDD-39	7.12%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Forestry Ramp-Up
Revenue Deficiency Impact of O&M Deferral
($000)

Case No.: U-21870
Exhibit No.: A-82 (PDD-58)
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	Description			Source
	(a)	(b)	(c)	(d)
	Revenue Requirement included in the Case			
1	Total O&M Expense LVD Line Clearing		174,844	A-170 (SES-1), Line 12 column (o)
2	Baseline O&M Expense of LVD Line Clearing		152,606	A-170 (SES-1), Line 12 column (p)
3	Increase in O&M Expense In Excess of Baseline		22,238	Line 1 - Line 2
	Revenue Requirement under Deferred O&M			
4	Deferred O&M Expense	22,238		Line 3
5	Average test year working capital	11,119		Line 4 / 2
6	Pre-tax Rate of Return	7.85%		A-14 (MRB-1)
7	Revenue Requirement of Deferred O&M		873	Line 5 x Line 6
8	**Revenue Deficiency Impact of O&M Deferral**		**(21,365)**	Line 7 - Line 3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response Revenue Requirement
(000)

Case No.: U-21870
Exhibit No.: A-83 (PDD-59)
Page: 1 of 3
Witness: PDDaly
Date: June 2025

Total Demand Response

Line	Description	Total	Source
(a)	(b)	(c)	(d)
1	**Residential Revenue Requirement**	**$21,321**	Exhibit A-83 (PDD-59), p 2
2	**C&I Revenue Requirement**	**$22,251**	Exhibit A-83 (PDD-59), p 3
3	**Total Demand Response Revenue Requirement**	**$43,572**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response Revenue Requirement
(000)

Case No.: U-21870
Exhibit No.: A-83 (PDD-59)
Page: 2 of 3
Witness: PDDaly
Date: June 2025

Residential Demand Response

Line	Description	4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	Total	
(a)	(b)	(c)	(d)	(e)	(f)	
1	**Total Capital Spending**	$ 202	$ 662	$ 1,375	$ 2,239	Exhibit A-12 (AMG-1)
	Revenue Requirement Calculation:					
					4/30/2027 Average	
2	Beginning Plant	$ 51,066	$ 51,268	$ 51,930		
3	Closings	202	662	1,375		
4	Ending Plant	$ 51,268	$ 51,930	$ 53,305	$ 52,618	
5	Beginning CWIP	$ -	$ -	$ -		
6	Capital Spending	202	662	1,375		
7	Closings	202	662	1,375		
8	Ending CWIP	$ -	$ -	$ -	$ -	
9	Beginning Depreciation Reserve	$ 10,273	$ 11,599	$ 15,763		
10	Depreciation Expense [1]	1,326	4,164	4,246		
11	End Depreciation Reserve	$ 11,599	$ 15,763	$ 20,009	$ 17,886	
12	Total Rate Base				$ 34,732	Line 4 + Line 8 - Line11
13	Pre-Tax Rate of Return				7.85%	Exhibit A-14 (MRB-1)
14	Return on Investment				$ 2,725	Line 12 * Line 13
15	Depreciation Expense				4,246	Line 10
16	O&M				13,648	Exhibit A-95 (AMG-2)
17	R&PP Tax				702	Footnote [2]
18	**Total Residential Revenue Requirement**				**$21,321**	

Footnotes

(1)
2024 Composite Depreciation Rate	8.07%
Jan-April 2025 Depreciation portion	32.11%

(2)
Average Plant Balance Test Year	$ 52,618	
Property Tax Rate	0.013349387	Source: Exh A-180 (BJV-1)
	$ 702	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Demand Response Revenue Requirement
(000)

Case No.: U-21870
Exhibit No.: A-83 (PDD-59)
Page: 3 of 3
Witness: PDDaly
Date: June 2025

Commercial and Industrial Demand Response

Line	Description	4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	Total	
(a)	(b)	(c)	(d)	(e)	(f)	
1	**Total Capital Spending**	$ 450	$ 960	$ 180	$ 1,590	Exhibit A-12 (AMG-1)
	Revenue Requirement Calculation:					
					4/30/2027 Average	
2	Beginning Plant	$ 6,347	$ 6,797	$ 7,757		
3	Closings	450	960	180		
4	Ending Plant	$ 6,797	$ 7,757	$ 7,937	$ 7,847	
5	Beginning CWIP	$ 85	$ 85	$ 85		
6	Capital Spending	450	960	180		
7	Closings	450	960	180		
8	Ending CWIP	$ 85	$ 85	$ 85	$ 85	
9	Beginning Depreciation Reserve	$ 2,580	$ 2,810	$ 3,604		
10	Depreciation Expense (1)	230	794	856		
11	End Depreciation Reserve	$ 2,810	$ 3,604	$ 4,460	$ 4,032	
12	Total Rate Base				$ 3,900	Line 4 + Line 8 - Line11
13	Pre-Tax Rate of Return				7.85%	Exhibit A-14 (MRB-1)
14	Return on Investment				$ 306	Line 12 * Line 13
15	Depreciation Expense				856	Line 10
16	O&M				20,983	Exhibit A-95 (AMG-2)
17	R&PP Tax				106	Footnote (2)
18	**Total C&I Revenue Requirement**				**$22,251**	

Footnotes

(1)
2024 Composite Depreciation Rate	10.91%
Jan-April 2025 Depreciation portion	32.11%

(2)
Average Plant Balance Test Year	$ 7,932	
Property Tax Rate	0.013349387	Source: Exh A-180 (BJV-1)
	$ 106	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Deferral Summary
Test Year Ending 2/28/2025
(000)

Case No.: U-21870
Exhibit No.: A-84 (PDD-60)
Page: 1 of 6
Witness: PDDaly
Date: June 2025

Line	Description	Source Page	Amount $(000)
(a)	(b)	(c)	(d)
1	March 2024 - February 2025 Revenue Requirement	3	13,473
2	March 2025 Revenue Requirement	4	2,224
3	April 2025 - February 2026 Revenue Requirement	5	7,325
4	March 2026 - April 2026 Revenue Requirement	6	1,305
5	**Total Deferred Revenue Requirement**		$ 24,327

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Deferral
(000)

Case No.: U-21870
Exhibit No.: A-84 (PDD-60)
Page: 2 of 6
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Date: June 2025

Line	Description	Actual 3/1/24 - 2/28/2025	U-21389 Approved 3/1/24 - 2/28/2025	Difference 3/1/24 - 2/28/2025	U-21585 Approved 3/1/24 - 2/28/2025	Difference 3/1/24 - 2/28/2025
(a)	(b)	(c)	(d)	(e) (c) - (d)	(f)	(g) (c) - (f)
	Capital Spending					
1	New Business	283,897	158,445	125,452	281,088	2,809
2	Demand Failures	249,688	147,563	102,125	188,947	60,741
3	Asset Relocations	62,047	52,467	9,580	53,278	8,769
4	**Total Capital Spending**	$ 595,632	$ 358,475	$ 237,157	$ 523,312	$ 72,319

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Distribution Deferral
(000)

Case No.: U-21870
Exhibit No.: A-84 (PDD-60)
Page: 3 of 6
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Date: June 2025

Line	Description		Amount	Source
(a)	(b)		(c)	(d)
	Revenue Requirement Calculation:			
1	Beginning Plant in Service	$	-	
2	Additional Capital Spending		237,157	Page 2, Column (e), Line 4
3	Ending Plant	$	237,157	Line 1 + Line 2
4	Average Plant in Service	$	118,578	Average (Line 1 & Line 3)
5	Beginning Depreciation Reserve	$	-	
6	Depreciation Expense [(1)]		3,534	Line 4 x 2.98%
7	End Depreciation Reserve	$	3,534	Line 5 + Line 6
8	Average Depreciation Reserve	$	1,767	Average (Line 5 & Line 7)
9	Total Average Rate Base	$	116,812	Line 3 Less Line 8
10	Return on Investment [(1)(2)]		8,469	Line 9 x 7.25%
11	R&PP Tax [(1)]		1,470	Line 4 x 1.24%
12	**Total 3/1/24 - 2/28/25 Revenue Requirement**	**$**	**13,473**	**Line 6 + Line 10 + Line 11**

[(1)] Depreciation rate of 2.98%, pretax cost of capital of 7.25%, and the property tax rate of 1.24% are from Case No. U-21389.

[(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-21870
Exhibit No.: A-84 (PDD-60)
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Witness: PDDaly
Date: June 2025

Line	Description		Amount	Source
(a)	(b)		(c)	(d)
	Revenue Requirement Calculation:			
1	Beginning Plant in Service	$	237,157	Page 3, Line 3
2	Additional Capital Spending		0	
3	Ending Plant	$	237,157	Line 1 + Line 2
4	Average Plant in Service	$	237,157	Average (Line 1 & Line 3)
5	Beginning Depreciation Reserve	$	3,534	
6	Depreciation Expense [1]		7,067	Line 4 x 2.98%
7	End Depreciation Reserve	$	10,601	Line 5 + Line 6
8	Average Depreciation Reserve	$	7,067	Average (Line 5 & Line 7)
9	Total Average Rate Base	$	230,090	Line 3 Less Line 8
10	Return on Investment [1][2]		16,681	Line 9 x 7.25%
11	R&PP Tax [1]		2,941	Line 4 x 1.24%
12	Total Revenue Requirement	$	26,690	Line 6 + Line 10 + Line 11
13	**March 2025 Deferred Revenue Requirement**	**$**	**2,224**	**Line 12 ÷ 12 x 1**

[1] Depreciation rate of 2.98%, pretax cost of capital of 7.25%, and the property tax rate of 1.24% are from Case No. U-21224.

[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-21870
Exhibit No.: A-84 (PDD-60)
Page: 5 of 6
Witness: PDDaly
Date: June 2025

Line	Description	Amount	Source
(a)	(b)	(c)	(d)
	Revenue Requirement Calculation:		
1	Beginning Plant in Service	$ 72,319	Page 2, Column (g), Line 4
2	Additional Capital Spending	0	
3	Ending Plant	$ 72,319	Line 1 + Line 2
4	Average Plant in Service	$ 72,319	Average (Line 1 & Line 3)
5	Beginning Depreciation Reserve	$ 3,534	
6	Depreciation Expense [1]	2,155	Line 4 x 2.98%
7	End Depreciation Reserve	$ 5,689	Line 5 + Line 6
8	Average Depreciation Reserve	$ 4,611	Average (Line 5 & Line 7)
9	Total Average Rate Base	$ 67,708	Line 3 Less Line 8
10	Return on Investment [1][2]	4,997	Line 9 x 7.38%
11	R&PP Tax [1]	839	Line 4 x 1.16%
12	Total Revenue Requirement	$ 7,991	Line 6 + Line 10 + Line 11
13	**April 2025 - Feb 2026 Deferred Revenue Requirement**	**$ 7,325**	**Line 12 ÷ 12 x 11**

[1] Depreciation rate of 2.98%, pretax cost of capital of 7.38%, and the property tax rate of 1.16% are from Case No. U-21585

[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-21870
Exhibit No.: A-84 (PDD-60)
Page: 6 of 6
Witness: PDDaly
Date: June 2025

Line	Description		Amount	Source
(a)	(b)		(c)	(d)
	Revenue Requirement Calculation:			
1	Beginning Plant in Service	$	72,319	Page 2, Column (g), Line 4
2	Additional Capital Spending		0	
3	Ending Plant	$	72,319	Line 1 + Line 2
4	Average Plant in Service	$	72,319	Average (Line 1 & Line 3)
5	Beginning Depreciation Reserve	$	5,689	
6	Depreciation Expense [1]		2,155	Line 4 x 2.98%
7	End Depreciation Reserve	$	7,844	Line 5 + Line 6
8	Average Depreciation Reserve	$	6,766	Average (Line 5 & Line 7)
9	Total Average Rate Base	$	65,553	Line 3 Less Line 8
10	Return on Investment [1][2]		4,838	Line 9 x 7.38%
11	R&PP Tax [1]		839	Line 4 x 1.16%
12	Total Revenue Requirement	$	7,832	Line 6 + Line 10 + Line 11
13	**March 2026 - April 2026 Revenue Requirement**	**$**	**1,305**	**Line 12 ÷ 12 x 2**

[1] Depreciation rate of 2.98%, pretax cost of capital of 7.38%, and the property tax rate of 1.16% are from Case No. U-21585

[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
Test Year Ending 2/28/2026
(000)

Case No.: U-21870
Exhibit No.: A-85 (PDD-61)
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line	Description	U-21585 Approved
(a)	(b)	(c)
	Capital Spending	
1	New Business	267,333
2	Demand Failures	206,177
3	Asset Relocations	51,859
4	**Total Capital Spending**	$ 525,369

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
SAP S/4HANA Implementation Project
Revenue Deficiency Impact of O&M Deferral
($000)

Case No.: U-21870
Exhibit No.: A-86 (PDD-62)
Page: 1 of 1
Witness: PDDaly
Date: June 2025

Line No.	Description			Source
	(a)	(b)	(c)	(d)
	Revenue Requirement included in the Case			
1	Investment O&M expense		15,178	Company witness Baker
	Revenue Requirement under Deferred O&M			
2	Deferred O&M Expense	15,178		Line 1
3	Average test year working capital	7,589		Line 2 / 2
4	Pre-tax Rate of Return	7.85%		A-14 (MRB-1)
5	Revenue Requirement of Deferred O&M		595	Line 3 X Line 4
6	**Revenue Deficiency Impact of O&M Deferral**		**(14,583)**	Line 5 - Line 1

MICHIGAN PUBLIC SERVICE COMMISSION U-21870
Consumers Energy Company Exhibit No.: A-87 (EAD-3)
Electric Cost-of-Service Study Page: 1 of 1
Capacity Related Cost and Charge Calculation Witness: EADavis
Projected 12-Month Period Ending April 30, 2027 Date: June 2025

Line No.	(a) Description	(b) Total Electric ($000)	(c) Capacity Charge	(d) Formula
1	Total Production Related Cost	$ 2,634,481		
2	Non-Capacity Related Cost:			
3	Fuel Expense	$ 548,348		
4	Purchased & Interchanged	766,888		
5	Energy Related Other O&M Expense	13,438		
6	PSCR Revenue Credits	(324,326)		
7	Non-PSCR Revenue Credits	(220,477)		
8	Transmission Expense	631,863		
9	Total Non-Capacity Related Cost	$ 1,415,735		Σ Lines 3:8
10	Total Capacity Related Cost	$ 1,218,747		Line 1 - Line 9
11	Offsets:			
12	Energy Market Sales	871,945		
13	Off-System Energy Sales	9,000		
14	Ancillary Service Sales	5,000		
15	Bilateral Energy Sales	0		
16	Total Revenue	$ 885,945		Σ Lines 12:15
17	Related Fuel Cost	545,993		
18	Total Revenue Less Fuel Cost	$ 339,952		Line 16 - Line 17
19	SRM Reconciliation	(461,000)		
20	Net Capacity Cost	$ 417,794		Line 10 - Line 18
21	Capacity Charge Demand (MW)		9,853	
22	Capacity Charge ($/MW-Day)		$116.17	[(Line 19 x 1,000) ÷ Line 20] ÷ 365

Source:
Lines 1-9: Exhibit A-16 (EAD-1) Schedule F-1
Lines 12-15,17, 19, 21 Company witness Megan L. Metz

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Substation Ownership Credit
(thousands of dollars)

U-21870
Exhibit No.: A-88 (EAD-4)
Page: 1 of 1
Witness: EADavis
Date: June 2025

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	$ 105,410	$ 123,498	$ 80,495	$ 12,991	$ 11,924	$ 99,435	$ 21,655	$ 2,407
2	Depreciation Reserve	(17,108)	(20,100)	(13,065)	(2,108)	(1,935)	(16,183)	(3,524)	(392)
3	Net Plant	88,301	103,398	67,430	10,882	9,989	83,252	18,131	2,015
4	Working Capital	3,570	4,029	2,462	644	464	3,155	767	107
5	CWIP (HV Distribution)	958	2,184	733	116	109	1,777	365	42
6	Substation Rate Base	$ 92,829	$ 109,611	$ 70,626	$ 11,642	$ 10,561	$ 88,184	$ 19,263	$ 2,165
7	Pre-Tax Return	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%
8	Pre-Tax Return ($)	$ 7,283	$ 8,600	$ 5,541	$ 913	$ 829	$ 6,919	$ 1,511	$ 170
9	Depreciation Expense	2,419	2,835	1,847	298	274	2,283	497	55
10	O&M Expense	788	924	602	97	89	744	162	18
11	Other Taxes	2,943	2,116	2,290	340	314	1,707	354	56
12	Revenue Credits	(677)	(561)	(532)	(74)	(71)	(458)	(89)	(14)
13	Total Revenue Requirement	$ 12,757	$ 13,914	$ 9,748	$ 1,574	$ 1,435	$ 11,194	$ 2,435	$ 285
14	Max Demand (MW)	6,987	7,187	4,910	1,306	771	5,393	1,421	373
15	Substation Ownership Credit (kW)	**$ 1.8258**	**$ 1.9361**	**$ 1.9852**	**$ 1.2059**	**$ 1.8598**	**$ 2.0756**	**$ 1.7141**	**$ 0.7640**

Source: Exhibit A-16 (EAD-1) Schedule F-1
WP-LMC-3 and 4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Allocation of Surcharges ($000)

Case No.: U-21870
Exhibit No.: A-89 (EAD-5)
Page: 1 of 3
Witness: EADavis
Date: June 2025

Line No	Description	Total Electric	Source
1	Demand Response ("DR")	$ 43,572	Exhibit PPD-59
2	Electric Rate Case ("ERC") Deferral	$ 24,327	Exhibit PPD-60
3	Investment Recovery Mechanism ("IRM")		
4	IRM 12 Mo Ending 4/30/2027	$ 22,244	Exhibit HJM-1
5	IRM 12 Mo Ending 4/30/2028	$ 63,199	Exhibit HJM-1

Line No	Description	Alloc	Total Electric	Total Residential	Total Commercial Secondary	Total Lighting & Unmetered	Total Primary	Rate GSG
			(a)	(c)	(d)	(f)	(e)	(g)
6	1/ Allocation of DR Surcharge	220	43,572	$ 21,318	$ 10,445	$ 123	$ 11,519	$ 167
7	ERC Deferral Surcharge							
8	1/ Distribution: Demand Related Cost		1,978,181	1,237,733	516,610	33,702	187,300	$ 2,836
9	1/ Distribution: Customer Related Cost		257,305	194,147	46,539	1,513	14,993	$ 113
10	Total Distribution Costs		2,235,486	$ 1,431,880	$ 563,148	$ 35,216	$ 202,293	$ 2,949
11	Total Distribution Costs (Allocator)		1.00000	0.64052	0.2519	0.0158	0.0905	0.0013
12	Allocation of ERC Surcharge		24,327	$ 15,582	$ 6,128	$ 383	$ 2,201	$ 32
13	Allocation of IRM Surcharge ending 4/30/2027		22,244	$ 14,248	$ 5,604	$ 350	$ 2,013	$ 29
14	Allocation of IRM Surcharge ending 4/30/2028		63,199	$ 40,480	$ 15,921	$ 996	$ 5,719	$ 83

Source:
Exhibit A-16 (EAD-2) Schedule F-1.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Allocation of Surcharges ($000)

Case No.: U-21870
Exhibit No.: A-89 (EAD-5)
Page: 2 of 3
Witness: EADavis
Date: June 2025

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)
3	1/ Allocation of DR Surcharge		$ 21,318	$ 21,318	$ 6,318	$ 4,127	$ 10,445	$ 4	$ 20	$ 99	$ 123
	ERC Deferral Surcharge										
7	1/ Distribution: Demand Related Cost		1,237,733	1,237,733	320,106	196,504	516,610	1,303	28,856	3,544	33,702
8	1/ Distribution: Customer Related Cost		194,147	194,147	37,135	9,404	46,539	79	1,349	85	1,513
9	Total Distribution Costs		$ 1,431,880	$ 1,431,880	$357,240	$ 205,908	$ 563,148	$ 1,382	$ 30,205	$ 3,629	$ 35,216
10	Total Distribution Costs (Allocator)		0.6405	0.6405	0.1598	0.0921	0.2519	0.00062	0.01351	0.00162	0.01575
11	Allocation of ERC Surcharge		$ 15,582	$ 15,582	$ 3,888	$ 2,241	$ 6,128	$ 15	$ 329	$ 39	$ 383
12	Allocation of IRM Surcharge ending 4/30/2027		$ 14,248	$ 14,248	$ 3,555	$ 2,049	$ 5,604	$ 14	$ 301	$ 36	$ 350
13	Allocation of IRM Surcharge ending 4/30/2028		$ 40,480	$ 40,480	$ 10,099	$ 5,821	$ 15,921	$ 39	$ 854	$ 103	$ 996

Source:
Exhibit A-16 (EAD-2) Schedule F-1.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Allocation of Surcharges ($000)

Case No.: U-21870
Exhibit No.: A-89 (EAD-5)
Page: 3 of 3
Witness: EADavis
Date: June 2025

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)
3	1/ Allocation of DR Surcharge		$ 874	$ 353	$ 538	$ 4,077	$ 1,020	$ 1,441	$ 2,840	$ 320	$ 49	$ 6	$ 11,519
	ERC Deferral Surcharge												
7	1/ Distribution: Demand Related Cost		17,026	2,172	4,671	66,158	12,812	21,356	60,611	1,971	391	132	187,300
8	1/ Distribution: Customer Related Cost		3,062	149	477	5,280	666	1,008	4,203	99	36	14	14,993
9	Total Distribution Costs		$ 20,088	$ 2,321	$ 5,148	$ 71,437	$ 13,479	$ 22,364	$ 64,814	$ 2,070	$ 427	$ 146	$ 202,293
10	Total Distribution Costs (Allocator)		0.00899	0.00104	0.00230	0.03196	0.00603	0.01000	0.02899	0.00093	0.00019	0.00007	0.09049
11	Allocation of ERC Surcharge		$ 219	$ 25	$ 56	$ 777	$ 147	$ 243	$ 705	$ 23	$ 5	$ 2	$ 2,201
12	Allocation of IRM Surcharge ending 4/30/2027		$ 200	$ 23	$ 51	$ 711	$ 134	$ 223	$ 645	$ 21	$ 4	$ 1	$ 2,013
13	Allocation of IRM Surcharge ending 4/30/2028		$ 568	$ 66	$ 146	$ 2,020	$ 381	$ 632	$ 1,832	$ 59	$ 12	$ 4	$ 5,719

Source:
Exhibit A-16 (EAD-2) Schedule F-1.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric O&M Expense
($000)

Case No.: U-21870
Exhibit No.: A-90 (MJF-1)
Page: 1 of 1
Witness: MJFoster
Date: June 2025

Corporate O&M

Line No.	(a) Program Description	(b) Source	(c) 2024 Actual	(d) 2025 Projected	(e) 2026 Projected	(f) 12 Months Ending 4/30/2027 Projected
1	Adjusted Corporate Services Expense	Exhibit A-91 (MJF-2)	$ 37,543	$ 38,331	$ 39,251	$ 36,968
2	Uncollectible Expense	Exhibit A-93 (MJF-4)	$ 18,074	18,998	18,998	20,274
3	Injuries & Damages Expense	Exhibit A-94 (MJF-5)	$ 7,677	5,083	5,083	5,083
4	**TOTAL O&M EXPENSES**		**$ 63,294**	**$ 62,412**	**$ 63,332**	**$ 62,325**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Projected Corporate Services O&M Expense
($000)

Case No.: U-21870
Exhibit No.: A-91 (MJF-2)
Page: 1 of 1
Witness: MJFoster
Date: June 2025

Line No.	Description	(a)	(b) 2024 Labor Actual	(c) 2024 Non-Labor Actual	(d) Total 2024 Actual	(e) 2025 Labor Inflation Projected	(f) 2025 N-Lbr Inflation Projected	(g) 12 Mos Ending 12/31/2025 Projected	(h) 2026 Labor Inflation Projected	(i) 2026 N-Lbr Inflation Projected	(j) 12 Mos Ending 12/31/2026 Projected	(k) 4 Mos Ending 4/30/27 Lbr Inflation Projected	(l) 4 Mos Ending 4/30/27 N-Lbr Inflation Projected	(m) Other Adjustment	(n) 12 Mos Ending 4/30/2027 Projected
1						(b) * Inflation	(c) * Inflation	(d) + (e) + (f)	[(b) + (e)] * Inflation	[(c) + (f)] * Inflation	(d) + (e) + (f)				(j) + (k) + (l) + (m)
2	Sustainability & External Affairs		$ 2,764	$ 2,243	$ 5,007	$ 58	$ 47	$ 5,112	$ 68	$ 55	$ 5,235	$ 23	$ 19	$ -	$ 5,277
3	Legal, Ethics, Regulatory, and Risk		7,136	19,207	26,343	150	403	26,896	175	471	27,542	60	161	(2,597)	25,165
4	People & Culture and Learning and Development		8,205	1,742	9,946	172	37	10,155	201	43	10,399	69	15	-	10,482
5	Finance and Shared Services		11,960	5,285	17,246	251	111	17,608	293	130	18,030	100	44	-	18,174
6	General Activities		(2,654)	(3,011)	(5,665)	(56)	(63)	(5,784)	(65)	(74)	(5,923)	(22)	(25)	-	(5,970)
7	Total		$ 27,410	$ 25,467	$ 52,877	$ 576	$ 535	$ 53,987	$ 672	$ 624	$ 55,283	$ 229	$ 213	$ (2,597)	$ 53,129
8	Less: EICP		14,442	-	14,442	303	-	14,745	354	-	15,099	121	-	-	$ 15,220
9	Less: Transfers Out		-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Corporate Service Departments		$ 12,968	$ 25,467	$ 38,435	$ 272	$ 535	$ 39,242	$ 318	$ 624	$ 40,184	$ 108	$ 213	$ (2,597)	$ 37,909
11	Administration & Other-Electric Portion		-	2,919	2,919	-	61	2,980	-	72	3,052	-	24	-	$ 3,076
12	**Total Corporate Services**		$ 12,968	$ 28,386	$ 41,354	$ 272	$ 596	$ 42,223	$ 318	$ 696	$ 43,236	$ 108	$ 237	$ (2,597)	$ 40,985
	Normalizations														
13	One-time Consultant Expense		-	(3,812)	(3,812)	-	(80)	(3,892)	-	(93)	(3,985)	-	(32)	-	$ (4,017)
14	**Total Normalizations**		$ -	$ (3,812)	$ (3,812)	$ -	$ (80)	$ (3,892)	$ -	$ (93)	$ (3,985)	$ -	$ (32)	$ -	$ (4,017)
15	**TOTAL ADJUSTED CORPORATE SERVICES EXPENSE**		$ 12,968	$ 24,575	**$ 37,543**	$ 272	$ 516	**$ 38,331**	$ 318	$ 602	**$ 39,251**	$ 108	$ 206	**$ (2,597)**	**$ 36,968**

		2025	2026	2027
16	Annual inflation rates per WP-PDD-37			
	Annual inflation rates	2.1%	2.4%	2.4%
	Number of months in the period	12	12	4
	Pro-rated inflation rate	2.1%	2.4%	0.8%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
S&P Global Market Intelligence Ranking of Consumers Energy Electric A&G Costs for 2023
Ranked by A&G per Customer (less Pension and Benefits)
(Companies over 500K Customers)

Case No.: U-21870
Exhibit No.: A-92 (MJF-3)
Page: 1 of 1
Witness: MJFoster
Date: June 2025

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Company Name	Total Customers (actual)	Total Admin & Gen: O&M Expense ($000)	Total Admin & Gen: Pension & Benefits ($000)	Total Admin & Gen: Excluding Pension & Benefits (d) - (e) ($000)	Total Admin & Gen: Excluding Pension & Benefits $/Customer (f)/(c) x $1,000	$/Customer Ranking
1	Ohio Power Company	1,523,794	64,072	-9,266	73,338	$48.13	1
2	Duke Energy Ohio, Inc.	752,909	49,306	7,263	42,043	$55.84	2
3	**Consumers Energy Company**	**1,884,290**	**67,227**	**-40,113**	**107,340**	**$56.97**	**3**
4	Wisconsin Electric Power Company	1,159,300	97,531	29,079	68,452	$59.05	4
5	MidAmerican Energy Company	820,668	75,919	25,104	50,815	$61.92	5
6	Public Service Electric and Gas Company	2,369,557	125,552	-27,412	152,964	$64.55	6
7	Public Service Enterprise Group Incorporated	2,369,557	125,552	-27,412	152,964	$64.55	7
8	Evergy Metro, Inc.	579,977	37,777	-468	38,245	$65.94	8
9	WEC Energy Group, Inc.	1,659,673	155,809	45,757	110,052	$66.31	9
10	Ohio Edison Company	1,069,766	46,565	-24,401	70,966	$66.34	10
11	CenterPoint Energy Houston Electric, LLC	2,753,976	242,169	52,924	189,245	$68.72	11
12	DTE Electric Company	2,266,460	238,578	75,564	163,014	$71.92	12
13	The Cleveland Electric Illuminating Company	756,673	78,801	23,176	55,625	$73.51	13
14	Public Service Company of Oklahoma	575,846	38,627	-3,980	42,607	$73.99	14
15	Metropolitan Edison Company	588,329	68,232	23,351	44,881	$76.29	15
16	Pennsylvania Electric Company	588,213	46,084	-112	46,196	$78.54	16
17	CenterPoint Energy, Inc.	2,909,158	290,357	61,423	228,934	$78.69	17
18	Virginia Electric and Power Company	2,752,726	264,764	42,175	222,589	$80.86	18
19	Appalachian Power Company	965,517	70,918	-10,421	81,339	$84.24	19
20	Public Service Company of Colorado	1,569,461	183,902	48,313	135,589	$86.39	20
21	West Penn Power Company	737,355	64,841	830	64,011	$86.81	21
22	Nevada Power Company	1,015,168	108,561	19,611	88,950	$87.62	22
23	Commonwealth Edison Company	4,130,538	441,205	74,977	366,228	$88.66	23
24	Florida Power & Light Company	5,845,147	547,158	25,433	521,725	$89.26	24
25	NextEra Energy, Inc.	5,845,147	562,017	25,419	536,598	$91.80	25
26	Dominion Energy, Inc.	3,542,947	410,578	83,932	326,646	$92.20	26
27	PECO Energy Company	1,700,223	184,377	17,303	167,074	$98.27	27
28	Central Maine Power Company	666,319	64,647	-1,915	66,562	$99.90	28
29	American Electric Power Company, Inc.	4,481,146	440,048	-37,624	477,672	$106.60	29
30	PPL Electric Utilities Corporation	1,472,437	158,321	1,288	157,033	$106.65	30
31	Avangrid, Inc.	2,321,099	243,877	-7,713	251,590	$108.39	31
32	Duke Energy Carolinas, LLC	2,845,809	351,358	38,022	313,336	$110.10	32
33	Exelon Corporation	9,225,536	1,215,815	176,078	1,039,737	$112.70	33
34	Ameren Illinois Company	1,226,027	88,022	-53,965	141,987	$115.81	34
35	OGE Energy Corp.	892,274	171,377	67,690	103,687	$116.21	35
36	Oklahoma Gas and Electric Company	892,274	171,377	67,690	103,687	$116.21	36
37	Puget Energy, Inc.	1,224,326	172,081	28,392	143,689	$117.36	37
38	Puget Sound Energy, Inc.	1,224,326	172,081	28,392	143,689	$117.36	38
39	Southwestern Electric Power Company	552,060	66,662	1,774	64,888	$117.54	39
40	Duke Energy Indiana, LLC	894,160	119,298	11,436	107,862	$120.63	40
41	New York State Electric & Gas Corporation	919,140	102,083	-10,577	112,660	$122.57	41
42	PPL Corporation	2,476,169	342,020	35,919	306,101	$123.62	42
43	Consolidated Edison Company of New York, Inc.	3,645,153	277,985	-174,234	452,219	$124.06	43
44	The Dayton Power and Light Company	539,127	80,410	12,497	67,913	$125.97	44
45	Evergy, Inc.	1,662,492	239,786	29,980	209,806	$126.20	45
46	Dominion Energy South Carolina, Inc.	790,221	140,183	39,911	100,272	$126.89	46
47	Baltimore Gas and Electric Company	1,336,794	209,771	38,291	171,480	$128.28	47
48	Consolidated Edison, Inc.	3,962,971	343,637	-167,210	510,847	$128.91	48
49	Xcel Energy Inc.	3,801,019	691,569	200,358	491,211	$129.23	49
50	Arizona Public Service Company	1,370,930	216,807	38,008	178,799	$130.42	50
51	Pinnacle West Capital Corporation	1,370,930	216,807	38,008	178,799	$130.42	51
52	Jersey Central Power & Light Company	1,163,141	175,048	23,186	151,862	$130.56	52
53	Georgia Power Company	2,735,261	315,548	-50,484	366,032	$133.82	53
54	Ameren Corporation	2,480,189	283,448	-61,214	344,662	$138.97	54
55	Northern States Power Company	1,556,301	329,363	108,296	221,067	$142.05	55
56	Oncor Electric Delivery Company LLC	3,936,106	680,454	117,846	562,608	$142.94	56
57	Alliant Energy Corporation	995,135	184,872	40,912	143,960	$144.66	57
58	Indiana Michigan Power Company	610,647	89,156	-337	89,493	$146.55	58
59	Duke Energy Progress, LLC	1,718,128	314,441	61,689	252,752	$147.11	59
60	NSTAR Electric Company	1,477,991	175,836	-43,912	219,748	$148.68	60
61	Atlantic City Electric Company	569,973	95,418	9,659	85,759	$150.46	61
62	Interstate Power and Light Company	500,038	98,241	22,527	75,714	$151.42	62
63	Union Electric Company	1,254,162	188,547	-7,254	195,801	$156.12	63
64	Kentucky Utilities Company	569,612	108,921	19,307	89,614	$157.32	64
65	Duke Energy Corporation	8,330,346	1,435,299	123,668	1,311,631	$157.45	65
66	Eversource Energy	3,296,846	485,985	-42,609	528,594	$160.33	66
67	Entergy Texas, Inc.	506,334	109,762	27,826	81,936	$161.82	67
68	Public Service Company of New Hampshire	537,201	89,877	704	89,173	$166.00	68
69	Delmarva Power & Light Company	549,745	102,526	11,024	91,502	$166.44	69
70	Potomac Electric Power Company	938,263	182,517	24,826	157,691	$168.07	70
71	Evergy Kansas Central, Inc.	738,636	154,088	28,976	125,112	$169.38	71
72	The Connecticut Light and Power Company	1,281,654	220,273	599	219,674	$171.40	72
73	The Southern Company	4,463,993	678,551	-101,941	780,492	$174.84	73
74	IDACORP, Inc.	625,440	174,739	61,209	113,530	$181.52	74
75	Idaho Power Company	625,440	174,739	61,209	113,530	$181.52	75
76	The AES Corporation	1,062,522	238,299	45,411	192,888	$181.54	76
77	Portland General Electric Company	928,859	222,693	49,091	173,602	$186.90	77
78	Duquesne Light Company	611,282	128,098	12,921	115,177	$188.42	78
79	Duquesne Light Holdings, Inc.	611,282	128,098	12,921	115,177	$188.42	79
80	Entergy Arkansas, LLC	729,557	212,309	67,048	145,261	$199.11	80
81	Entergy Louisiana, LLC	1,104,472	340,835	113,862	226,973	$205.50	81
82	Niagara Mohawk Power Corporation	1,542,713	359,022	40,457	318,565	$206.50	82
83	Alabama Power Company	1,537,035	274,702	-55,290	329,992	$214.69	83
84	Entergy Corporation	3,009,516	923,653	272,927	650,726	$216.22	84
85	UNS Energy Corporation	550,256	148,148	28,426	119,722	$217.58	85
86	AES Indiana	523,395	157,889	32,914	124,975	$238.78	86
87	TXNM Energy, Inc.	820,083	227,572	26,936	200,636	$244.65	87
88	Tampa Electric Company	834,144	255,708	36,062	219,646	$263.32	88
89	TECO Energy, Inc.	834,144	255,708	36,062	219,646	$263.32	89
90	Public Service Company of New Mexico	548,019	177,866	20,655	157,211	$286.87	90
91	Duke Energy Florida, LLC	1,968,213	576,847	1,149	575,698	$292.50	91
92	National Grid USA	2,583,968	926,117	110,732	815,385	$315.56	92
93	Edison International	5,263,405	2,149,362	57,140	2,092,222	$397.50	93
94	Southern California Edison Company	5,263,405	2,149,362	57,140	2,092,222	$397.50	94
95	Massachusetts Electric Company	635,003	319,669	43,085	276,584	$435.56	95
96	Berkshire Hathaway Energy Company	4,280,660	2,198,281	180,335	2,017,946	$471.41	96
97	Pacific Gas and Electric Company	5,649,612	3,534,378	383,249	3,151,129	$557.76	97
98	PG&E Corporation	5,649,612	3,534,378	383,249	3,151,129	$557.76	98
99	PacifiCorp	2,069,044	1,953,618	123,037	1,830,581	$884.75	99
100	San Diego Gas & Electric Company	512,632	626,994	63,809	563,185	$1,098.61	100

S&P Global Market Intelligence, 55 Water Street, New York, NY 10041
Columns c-e from S&P Global for regulated electric companies with more than 500,000 customers.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Uncollectible Accounts Expense
($000)

Case No.: U-21870
Exhibit No.: A-93 (MJF-4)
Page: 1 of 2
Witness: MJFoster
Date: June 2025

Line No.	(a) Description	(b) 2024 Actual	(c) 2025 Projected	(d) 2026 Projected	(e) 12 Months Ending 4/30/2027 Projected
1	Uncollectible Accounts Expense	$ 18,074	$ 18,998 [1]	$ 18,998 [2]	**$ 20,274** [3]

[1] 2025 projected amount based on U-21585 order
[2] 2026 projected amount based on U-21585 order
[3] Exhibit A-93 (MJF-4) Page 2, line 9, column (e)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Uncollectible Accounts Expense
for 12 Mos. Ending 4/30/2027
($000)

Case No.: U-21870
Exhibit No.: A-93 (MJF-4)
Page: 2 of 2
Witness: MJFoster
Date: June 2025

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	2020	22,393	11,965	10,428	4,147,450	0.251%
2	2021	26,335	10,844	15,491	4,681,931	0.331%
3	2022	27,543	8,726	18,817	4,737,236	0.397%
4	2023	29,146	7,478	21,668	4,709,798	0.460%
5	2024	25,816	7,742	18,074	4,934,300	0.366%
6	3-Year Average 2022 - 2024	$ 27,501	$ 7,982	$ 19,519	$ 4,793,778	0.407%
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)				$ 4,979,036	
8	3-Year Average 2022 - 2024				0.407%	
9	Test Year Total Uncollectible Accounts Expense				**$ 20,274**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Injuries & Damages Expense
for the Years 2020 Through the 12 Months Ending 4/30/2027
($000)

Case No.: U-21870
Exhibit No.: A-94 (MJF-5)
Page: 1 of 1
Witness: MJFoster
Date: June 2025

Line No.	(a) Program Description		(b) 2020 Actual	(c) 2021 Actual	(d) 2022 Actual	(e) 2023 Actual	(f) 2024 Actual	(g) 12 Mos Ending 12/31/2025 Projected	(h) 12 Mos Ending 12/31/2026 Projected	(i) 12 Mos Ending 4/30/2027 Projected
1	Electric Injuries & Damages	[1]	$ 2,021	$ 2,694	$ 5,567	$ 4,311	$ 6,619	$ 4,242	$ 4,242	$ 4,242
2	Internal Legal Costs	[2]	452	412	424	474	441	441	441	441
3	Workers' Compensation	[3]	(139)	401	661	462	617	400	400	400
4	Total Electric Injuries & Damages		**$ 2,334**	**$ 3,507**	**$ 6,652**	**$ 5,246**	**$ 7,677**	**$ 5,083**	**$ 5,083**	**$ 5,083**

[1] Electric Injuries & Damages costs are 2020 - 2024 actual expense. 2025, 2026, and Test Year Ending 4/30/2027 used a 5-year average (2020 - 2024).

[2] Electric Internal Legal costs are 2020 - 2024 actual expense. 2025, 2026, and Test Year Ending 4/30/2027 used a 5-year average (2020 - 2024).

[3] Electric Workers' Compensation costs are 2020 - 2024 actual expense. 2025, 2026, and Test Year Ending 4/30/2027 used a 5-year average (2020 - 2024).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
For Demand Response C&I and Residential Programs
($000)

Case No.: U-21870
Exhibit No.: A-95 (AMG-2)
Page: 1 of 2
Witness: AMGast
Date: June 2025

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2024	(c) Projected 12-Mos Ending 4/30/2027
1	Demand Response (C&I)	16,694	20,983
	Labor	4,106	3,998
	Material	13	16
	Contractor	5,827	8,745
	Non-Labor Overhead	-	-
	Non-Labor Other	6,748	8,224
2	Demand Response (Res)	14,546	13,648
	Labor	3,016	2,763
	Material	163	119
	Contractor	7,670	8,074
	Non-Labor Overhead	-	-
	Non-Labor Other	3,697	2,692
3	Total Demand Response O&M Expenses	31,240	34,630
	Labor	7,122	6,761
	Material	176	135
	Contractor	13,497	16,819
	Non-Labor Overhead	-	-
	Non-Labor Other	10,444	10,916

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Add Description
($000)

Case No.: U-21870
Exhibit No.: A-95 (AMG-2)
Page: 2 of 2
Witness: AMGast
Date: June 2025

Line No.	Description	(a)	(b) 12-Mos Ended 12 Mos Ended 12/31/2024	(c) Base O&M for Merit & Inflation 12 Mos Ended 12/31/2024	(d) Merit & Inflation 12 Mos Ending 12/31/2025	(e) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2025	(f) Merit & Inflation 12 Mos Ending 12/31/2026	(g) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2026	(h) Merit & Inflation 4 Mos Ending 4/30/2027	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending 4/30/2027
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	Demand Response (C&I)		16,694	16,694	351	17,044	409	17,453	140	3,390	20,983
	Labor		4,106	4,106	86	4,192	101	4,293	34	(329)	3,998
	Material		13	13	0	13	0	13	0	2	16
	Contractor		5,827	5,827	122	5,949	143	6,092	49	2,605	8,745
	Non-Labor Overhead		0	0	0	0	0	0	0	0	0
	Non-Labor Other		6,748	6,748	142	6,889	165	7,055	56	1,113	8,224
2	Demand Response (Res)		14,546	14,546	305	14,852	356	15,208	122	(1,682)	13,648
	Labor		3,016	3,016	63	3,079	74	3,153	25	(416)	2,763
	Material		163	163	3	167	4	171	1	(53)	119
	Contractor		7,670	7,670	161	7,831	188	8,019	64	(10)	8,074
	Non-Labor Overhead		0	0	0	0	0	0	0	0	0
	Non-Labor Other		3,697	3,697	78	3,774	91	3,865	31	(1,204)	2,692
3	Total Demand Response O&M Expenses		31,240	31,240	656	31,896	765	32,661	261	1,708	34,630
	Labor		7,122	7,122	150	7,272	175	7,446	60	(745)	6,761
	Material		176	176	4	180	4	184	1	(51)	135
	Contractor		13,497	13,497	283	13,781	331	14,112	113	2,595	16,819
	Non-Labor Overhead		0	0	0	0	0	0	0	0	0
	Non-Labor Other		10,444	10,444	219	10,663	256	10,919	87	(91)	10,916

Notes

	12-Mo Ending 2025	12-Mo Ending 2026	4-Mo Ending 2027
Annual inflation rates per Company witness Daly	2.1%	2.4%	2.4%
Number of months in the period	12	12	4
Pro-rated inflation rate	2.1%	2.4%	0.8%

1. Tariff Sheet Nos. A-4.00, A-5.00, C-50.00, C-51.00 and D-80.00 – Rule C10.4 – **Experimental Advanced Renewable Program – Anaerobic Digestion Program** – Canceled Tariff Sheets to remove rule C10.4 and to remove from Rate Schedules.

2. Tariff Sheet No. C-4.00 – Rule C1 – **Characteristics of Service** – Updated Contribution in Aid of Construction Allowance Sheet.

3. Tariff Sheet No. C-15.00 – Rule C4.4 – **Resale** – Revised all inclusive rate per kWh for resale.

4. Tariff Sheet No. C-18.00 – Rule C4.5 – **Mobile Home Park** – Updated New Service Connection fee for underground service.

5. Tariff Sheet Nos. C-23.00 and C-24.00 – **Shutoff Protection Plan for Residential Customers** – Expanded income eligibility for the Shutoff Protection Plan by raising the income eligibility limit.

6. Tariff Sheet No. C-25.00 – Rule C5.5 – **Non-Transmitting Meter Provision** – Revised monthly and upfront charges when electing a non-transmitting meter.

7. Tariff Sheet Nos. C-26.20 through C-28.00 – Rule C6.1 – **Overhead Extension Policy** – Added New Service Connection fee for overhead service and reformatted Tariff Sheet.

8. Tariff Sheet Nos. C-31.00 and C-32.00 – Rule C6.2 – **Underground Policy** – Updated New Service Connection fee for underground service.

9. Tariff Sheet No. C-36.00 – Rule C8 – **Power Supply Cost Recovery** – Updated the PSCR adjustment factor.

10. Tariff Sheet Nos. C-64.30 through C-64.50 – Rule C11.3 – **Distributed Generation Program** – Updated tariffs to reflect revised outflow credits.

11. 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.

12. Tariff Sheet No. C-78.00 – Rule C18 – **Standard Offer - Purchased Power** – Revised Standard Offer PPA to require a minimum contract term of one year.

13. Tariff Sheet Nos. D-2.20, D-2.40, and D-5.00 – **Surcharges** – Updated to add the Investment Recovery Mechanism Surcharge, the Electric Rate Case Deferral Surcharge, and the Electric Rate Case Demand Response Surcharge.

14. 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.

15. Tariff Sheet No. D-48.00 – **General Service Time of Use Rate GSTU** – Clarified eligibility for participation in Demand Response Programs under Rate GSTU.

16. Tariff Sheet No. D-63.00 – **Aggregate Peak Demand Service Provision (GAP)** – Modified eligibility to permit Company-approved enrollment exceptions.

17. Tariff Sheet Nos. D-78.30 and D-78.40 – **Large Economic Development Rate LED** – Added Adjustment for Power Factor, included a facilities allowance for funding incremental distribution facilities needed to serve a customer's load and reformatted Tariff Sheet.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Employee Benefits O&M Expenses
For the Years 2024 and Test Year 12 Months ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-97 (KKG-1)
Page: 1 of 2
Witness: KKGrob
Date: June 2025

Line No.	(a) Description	(b) Actual 12 mos. ended 12/31/2024	(c) Projected 12 mos. Ending 4/30/2027
1	Pension Plans A/B	**($51,785)**	**($45,156)**
2	Defined Company Contribution Plan	**14,774**	**16,507**
3	401 (k) Employees' Savings Plan	**11,396**	**12,731**
4	Active Health Care/Life Insurance/LTD	**29,089**	**33,385**
5	Retiree Health Care and Life Insurance	**(47,536)**	**(48,867)**
6	Other Benefits	**2,601**	**2,780**
7	Pension Volatility Mechanism Deferral	**10,729**	**0**
8	OPEB Volatility Mechanism Deferral	**3,579**	**0**
9	Pension Volatility Mechanism Amortization	**(1,147)**	**(1,912)**
10	OPEB Volatility Mechanism Amortization	**2,330**	**1,813**
11	**Total Expense**	**($25,970)**	**($28,719)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Merit and Inflation
For the Years 2024 and Test Year 12 Months ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-97 (KKG-1)
Page: 2 of 2
Witness: KKGrob
Date: June 2025

Line No.	Description	2024 Actual	Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 12 Mos Ending Dec 31, 2026	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026	Merit & Inflation 4 Mos Ending 4/30/207	Other Adjustments	Projected O&M 12 Mos Ending 4/30/2027
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Pension Plans A/B**	**$ (51,785)**	**$ (51,785)**	**$ (1,087)**	**$ (52,872)**	**$ (1,269)**	**$ (54,141)**	**$ (433)**	**$9,419**	**$ (45,156)**
2	**Defined Company Contribution Plan**	**$ 14,774**	**$ 14,774**	**$ 310**	**$ 15,084**	**$ 362**	**$ 15,446**	**$ 124**	**$ 937**	**$ 16,507**
3	**401 (k) Employees' Savings Plan**	**$ 11,396**	**$ 11,396**	**$ 239**	**$ 11,635**	**$ 279**	**$ 11,915**	**$ 95**	**$ 721**	**$ 12,731**
4	**Active Health Care/Life Insurance/LTD**	**$ 29,089**	**$ 29,089**	**$ 611**	**$ 29,700**	**$ 713**	**$ 30,413**	**$ 243**	**$ 2,729**	**$ 33,385**
5	**Retiree Health Care and Life Insurance**	**$ (47,536)**	**$ (47,536)**	**$ (998)**	**$ (48,534)**	**$ (1,165)**	**$ (49,699)**	**$ (398)**	**$ 1,230**	**$ (48,867)**
6	**Other Benefits**	**$ 2,601**	**$ 2,601**	**$ 55**	**$ 2,656**	**$ 64**	**$ 2,719**	**$ 22**	**$ 39**	**$ 2,780**
	Other Benefits non labor	**1,714**	**1,714**	**36**	**1,750**	**42**	**1,792**	**14**	**26**	**1,832**
	Other Benefits labor	**887**	**887**	**19**	**906**	**22**	**927**	**7**	**13**	**948**
7	**Pension Volatility Mechanism Deferral**	**$ 10,729**	**$ 10,729**	**$ 225**	**$ 10,954**	**$ 263**	**$ 11,217**	**$ 90**	**($11,307)**	**$ 0**
8	**OPEB Volatility Mechanism Deferral**	**$ 3,579**	**$ 3,579**	**$ 75**	**$ 3,654**	**$ 88**	**$ 3,742**	**$ 30**	**($3,772)**	**$ 0**
9	**Pension Volatility Mechanism Amortization**	**$ (1,147)**	**$ (1,147)**	**$ (24)**	**$ (1,171)**	**$ (28)**	**$ (1,199)**	**$ (10)**	**($703)**	**$ (1,912)**
10	**OPEB Volatility Mechanism Amortization**	**$ 2,330**	**$ 2,330**	**$ 49**	**$ 2,379**	**$ 57**	**$ 2,436**	**$ 19**	**($643)**	**$ 1,813**
11	**Total Employee Benefits O&M Expenses**	$ (25,970)	$ (25,970)	$ (545)	$ (26,515)	$ (636)	$ (27,152)	$ (217)	$ (1,350)	$ (28,719)
	Nonlabor	$ (26,857)	$ (26,857)	$ (564)	$ (27,421)	$ (658)	$ (28,079)	$ (225)	$ (1,363)	$ (29,667)
	Labor	887	887	19	906	22	927	7	13	948

Notes

	12-Mo Ending 2025	12-Mo Ending 2026	4-Mo Ending 2027
Annual inflation rates per Company witness Rayl	2.1%	2.4%	2.4%
Number of months in the period	12	12	4
Pro-rated inflation rate	2.1%	2.4%	0.8%

CMS Energy

Prepared on January 17, 2025

ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

	2024	2025	2026	2027
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	2,770	2,729	2,649	2,580
PBGC Liability	$ 1,158.1	$ 1,080.7	$ 1,094.1	$ 1,120.9
Market Value of Assets	$ 1,758.4	$ 1,741.4	$ 1,781.1	$ 1,822.6
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	$ 1,280.9	$ 1,250.7	$ 1,258.6	$ 1,263.9
Market Value of Assets	1,758.4	1,741.4	1,781.1	1,822.6
Funded Status	$ (477.5)	$ (490.7)	$ (522.5)	$ (558.7)
ASC 715 Funded %	137.3%	139.2%	141.5%	144.2%
ASC 715 Accounting Expense				
Utility	$ (42.4)	$ (39.3)	$ (41.4)	$ (40.7)
Nonutility	(1.2)	(1.1)	(1.2)	(1.1)
Total ASC 715 Accounting Expense	$ (43.6)	$ (40.4)	$ (42.6)	$ (41.8)
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	$ (33.0)	$ (29.8)	$ (32.0)	$ (31.2)
Components of Total Expense				
Service Cost	$ 26.1	$ 23.5	$ 21.8	$ 20.1
Interest Cost	61.3	65.7	66.0	66.2
Expected Return on Assets	(135.3)	(133.3)	(133.3)	(132.1)
Amortization of Outstanding Components	4.3	3.7	2.9	4.0
Total ASC 715 Accounting Expense	$ (43.6)	$ (40.4)	$ (42.6)	$ (41.8)
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	$ (33.0)	$ (29.8)	$ (32.0)	$ (31.2)
Market Related Value of Assets	$ 1,842.2	$ 1,867.1	$ 1,869.5	$ 1,853.1
Assumptions				
Discount Rate	5.05%	5.73%	5.73%	5.73%
Expected Return on Assets	7.50%	7.30%	7.30%	7.30%
Salary Increases	3.55%	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 on January 17, 2025

ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

	2024	2025	2026	2027
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	7,309	7,147	6,975	6,795
PBGC Liability	$ 953.2	$ 853.1	$ 819.5	$ 789.2
Market Value of Assets	$ 1,245.9	$ 1,222.8	$ 1,229.7	$ 1,238.3
PBGC Flat Rate Premium	$ 0.7	$ 0.7	$ 0.7	$ 0.7
PBGC Variable Rate Premium	0.0	0.0	0.0	0.0
Total PBGC Premium	$ 0.7	$ 0.7	$ 0.7	$ 0.7
Projected Benefit Obligation	$ 914.4	$ 843.8	$ 810.5	$ 776.9
Market Value of Assets	1,245.9	1,222.8	1,229.7	1,238.3
Funded Status	$ (331.5)	$ (379.0)	$ (419.2)	$ (461.4)
ASC 715 Funded %	136.3%	144.9%	151.7%	159.4%
ASC 715 Accounting Expense				
Utility	$ (38.9)	$ (36.0)	$ (32.7)	$ (27.3)
Nonutility	(4.1)	(3.9)	(3.6)	(3.0)
Total	$ (43.0)	$ (39.9)	$ (36.3)	$ (30.3)
Components of Total Expense				
Service Cost	$ 1.6	$ 1.7	$ 1.7	$ 1.7
Interest Cost	42.6	42.7	40.9	39.1
Expected Return on Assets	(98.6)	(95.1)	(92.6)	(88.8)
Amortization of Outstanding Components	11.4	10.8	13.7	17.7
Total Expense	$ (43.0)	$ (39.9)	$ (36.3)	$ (30.3)
Market Related Value of Assets	$ 1,354.1	$ 1,341.4	$ 1,307.4	$ 1,255.7
Assumptions				
Discount Rate	4.95%	5.59%	5.59%	5.59%
Expected Return on Assets	7.50%	7.30%	7.30%	7.30%
Salary Increases	3.65%	3.80%	3.80%	3.80%

2025-2027 projections reflect the following:

- January 1, 2024 census data.
- PBO discount rate of 5.73% (Plan A) and 5.59% (Plan B) in fiscal 2025+, based on Decebmer 31, 2024 yield curve anlaysis.
- Service Cost effective interest rate of 5.77% (Plan A) and 5.81% (Plan B) in fiscal 2025+, based on December 31, 2024 yield curve analysis.
- Interest Cost effective interest rate of 5.43% (Plan A) and 5.30% (Plan B) in fiscal 2025+, based on December 31, 2024 yield curve analysis.
- Expense is allocated to Utility/Non Utility based on PBO using the preliminary allocation percentages for 2025 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, 2024 market assets provided by CMS, with expected returns thereafter.
- Expected and actual asset returns of 7.30% in fiscal 2025+.
- 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, 2024 ASC 715 disclosures.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

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ASC 715 OPEB Expense Estimates ($ millions)

	2024	2025	2026	2027
Funded Status, January 1				
Accumulated Postretirement Benefit Obligation	$ (899.9)	$ (831.0)	$ (826.0)	$ (818.7)
Plan Assets at Fair Value	$ 1,558.9	$ 1,588.2	$ 1,640.8	$ 1,695.2
Funded Status	$ 659.0	$ 757.2	$ 814.8	$ 876.5
ASC 715 Accounting Expense				
Utility	$ (80.8)	$ (83.9)	$ (86.7)	$ (76.7)
Nonutility	$ (6.7)	$ (6.9)	$ (7.1)	$ (7.0)
Total	$ (87.5)	$ (90.8)	$ (93.8)	$ (83.7)
Components of Total Expense				
Service Cost	$ 11.3	$ 8.4	$ 8.2	$ 7.9
Interest Cost	$ 42.9	$ 43.2	$ 42.9	$ 42.5
Expected Return on Assets	$ (114.8)	$ (111.4)	$ (115.3)	$ (119.0)
Amortization of Net (Gain) or Loss	$ 3.9	$ 2.7	$ 2.2	$ 1.6
Amortization of Prior Service Cost	$ (30.8)	$ (33.7)	$ (31.8)	$ (16.7)
Total Expense	$ (87.5)	$ (90.8)	$ (93.8)	$ (83.7)
Assumptions				
APBO Discount Rate	5.02%	5.69%	5.69%	5.69%
Service Cost Effective Interest Rate	5.12%	5.85%	5.85%	5.85%
Interest Cost Effective Interest Rate	4.91%	5.39%	5.39%	5.39%
Expected Return on Assets	7.50%	7.15%	7.15%	7.15%
Trend Rate—Initial Pre-65	8.00%	8.50%	8.00%	7.50%
Trend Rate—Initial Post-65	8.50%	10.25%	9.75%	9.00%
Trend Rate—Ultimate	4.75%	4.75%	4.75%	4.75%
Trend Rate—Ultimate Year Pre-65	2032	2033	2033	2033
Trend Rate—Ultimate Year Post-65	2032	2033	2033	2033
Expected Contribution	$ 0.0	$ 0.0	$ 0.0	$ 0.0

2025-2027 expense projections reflect the following:

-January 1, 2024 census data.
-APBO discount rate of 5.69% in fiscal 2025+, based on December 31, 2024 yield curve.
-Service Cost effective interest rate of 5.85% in fiscal 2025+, based on December 31, 2024 yield curve.
-Interest Cost effective interest rate of 5.39% in fiscal 2025+, based on December 31, 2024 yield curve.
-December 31, 2024 market assets, provided by CMS
-Other provisions, assumptions and methods are the same as those used for December 31, 2024 ASC 715 disclosures.

EXHIBIT A-100 (KKG-4)
IS CONFIDENTIAL AND BEING FILED
UNDER SEAL WITH THE MPSC